Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

2013 General Rate Application

May 8, 2012

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1 INTRODUCTION

This is an application for a change in power rates to reflect major increases in the cost of making electricity in Nova Scotia. Our Application comes at a time when many Nova Scotia households and businesses are struggling to manage increases in the cost of heating oil, gasoline, tap water, groceries, and other necessities. We realize customers will be unhappy to hear NS Power is asking for another increase.

In recognition of those concerns, NS Power seeks approval of a Rate Stabilization Plan that will limit rate increases for all customer classes to 3 percent in 2013, and a further 3 percent in 2014. That's equivalent to an additional $3.50 in an average household's monthly bill in each of those years. Because this amount will not fully recover the exceptional costs facing NS Power, the plan proposes to defer a portion of those costs for recovery in future years.

We make this Application amidst major changes in the way we produce and consume electricity in Nova Scotia. The changes are big, they are complicated, and they are happening at a rapid pace. We are adjusting to large load reductions in the pulp and paper industry. We are reducing our use of imported coal, and switching instead to natural gas, and Nova Scotia renewables like wind and biomass.

The changes underway in our electricity system make good sense for all sorts of reasons. Without them, Nova Scotia would be headed for an unsustainable future – a future of much higher energy costs, uncompetitive industry, and environmental harm. We understand the difficulty such a transition presents for households and businesses, but we are convinced that sticking with imported, high-carbon fuels now would ensure far greater problems down the road. The changes we are implementing offer the best, long term prospect for securing Nova Scotia's economy and environment.

That is why we've taken the unusual step of asking the Board – the regulator whose approval is required for major investments in the utility, and for all changes in electricity rates – to set rates for a two-year period. We are trying to provide customers with a view of future rates so they can plan for changes.

We will continue to work with customer representatives to smooth the impact of rate increases over the coming years. To that end, NS Power proposed a year ago to limit rate increases to 4 percent in each of 2012, 2013 and 2014. Unfortunately, we could not reach a consensus on that proposal, so we applied for a one-year increase. This year is similar to last, in that we can see rate pressure coming for the next few years. We want to be upfront with our customers and share the facts we have.

That is why we have taken the additional step of proposing a Rate Stabilization Plan to limit rate increases for the next two years by postponing recovery of some of the unusual costs affecting electricity production in Nova Scotia. The plan, detailed in Section 2, offers a prudent and responsible way to manage these costs, while giving NS Power and our customers time to adjust to rapid changes in Nova Scotia's electricity system.

Many forces have combined to change the basic structure of our electricity system, and put upward pressure on customer rates. The biggest factor in this Application is the loss of pulp and paper industry load. Over the last year, our two largest customers faced the prospect of permanent closure. The province's largest paper mill, in Port Hawkesbury, has been shut down since September 2011. We hope it will resume partial operation this fall under new ownership, but in the foreseeable future, there is no realistic prospect it will contribute more than a minimal amount to the fixed costs of our electricity system. After a brief shutdown, the second largest mill has resumed production intermittently, at reduced levels, and it has done so under a "load retention" rate that limits its contributions to fixed system costs.

While the rates paid by these large customers may cover the cost of fuel needed to generate their reduced electricity needs, they will make little or no contribution to capital investments, operating costs, and maintenance. This leaves fewer customers to share the fixed costs of Nova Scotia's electricity system.

We are actively seeking ways to reduce fixed costs as the load on our system decreases. During the 2012 GRA, NS Power President and CEO Rob Bennett committed to cost control measures.[1] Since that time, we have laid-off employees, cut programs, and reduced some NS Power generators to seasonal operation only. We will continue to cut costs where we can do so prudently, without compromising safe, reliable service to customers.

Rising fuel costs encourage us to look for more efficient ways to generate electricity. Society's growing concern for the environment encourages us to seek cleaner, more sustainable generation. Concern for the provincial economy encourages us to reduce our exposure to volatile world fuel prices, and replace future spending on foreign fuel with investment in local energy production.

We haven't taken these decisions on our own. Government regulations are helping control air emissions that damage the environment. Many of our customers are concerned about air quality and climate change. They have asked us to play a role in meeting those challenges.

NS Power predicts that meeting Nova Scotia's Renewable Electricity Standard by incorporating new renewable energy into our generation mix will add an incremental 1 or 2 percent per year to the factors that affect rates. Renewable projects that are fuel free, like wind and hydro, offer long term protection against fluctuations in world coal markets. In the early years of compliance, the cost of wind projects was offset by favourable tax deductions, so customers did not pick up the full tab for adding renewable energy. Those beneficial tax deductions disappear in 2013 and 2014, so rates will reflect the costs of new renewable investments in those years.

[1] NSPI 2012 General Rate Application, Hearing Transcript, NSUARB-NSPI-P-892, September 21, 2011, page 241 line 22 to page 241, line 13.

We are already seeing the benefits of new renewable generation and natural gas. We have cut coal generation from more than 80 percent of our power production in 2006 to less than 50 percent in 2013. For an industry that traditionally plans decades ahead, that is a rapid about-face. We did it by installing new renewable energy, and by taking advantage of low-priced natural gas. Our coal use may fluctuate in the short term as we constantly seek the best energy value, but the long-term trend will continue downward.

The combined impact of these changes require difficult adjustments for NS Power and our customers. Homeowners and businesses cannot stop using the electrical system, any more than we can halt production or freeze prices while we invest in changes that improve our product.

Changes on this scale involve short-term costs, but we are carrying them out in a thoughtful, responsible, orderly manner. We are providing customers with a candid view of future rates, so they can plan and budget for increases. We continue to work with customer representatives to smooth the impact of these increases.

Accordingly, NS Power seeks approval of a Rate Stabilization Plan, set forth in detail in Section 2. The Rate Stabilization Plan provides just and reasonable rates, while extending an existing deferral mechanism to give our customers and the Company more time to adapt to the loss of pulp and paper industry load, and the transformation in our generation mix. The Rate Stabilization Plan requires a net 3 percent increase in electricity rates in 2013, and a further net 3 percent increase in 2014.

In both years, the increases are “net” in the sense that they incorporate the elimination of a planned change in the Fuel Adjustment Mechanism (FAM) that would otherwise have reduced rates. Customer charges under the 2010 FAM deferral were to have declined in 2013, and expired in 2014. Under the Rate Stabilization Plan, those planned rate reductions will not take place, and rates will change by an additional 3 percent per year in 2013 and 2014.

Taken together, these changes will result in an average total increase of about $3.50 per month for residential customers in 2013, and a further $3.50 per month in 2014.

These increases will not fully cover our forecast revenue shortfall of $130.3 million in 2013, and $67.5 million in 2014. Under the Rate Stabilization Plan, recovery of the remaining shortfall would be deferred until 2015, when the Section 21 Tax Deferral is scheduled to wind up. The Plan would extend this recovery mechanism by a further eight years. We believe this is a responsible way to ease the impact of a sudden major loss of load combined with a system-wide transition to new generation technologies.

If the Board does not approve the Rate Stabilization Plan, the revenue requirement can be recovered through traditional rate-setting practices. The tables below show the rate impact by for each class of customer in 2013 and 2014, under the traditional approach to recovering the revenue requirement and setting rates.

Figure 1-1

Combined Revenue Effect of all Rate Changes in 2013*
(as Measured Against 2013 Revenues at Present Rates
Adjusted for FAM Effects from 2012)

Rate Classes	2013 GRA	2013 FAM AA	2013 FAM BA	2013 Combined Effect
ATL				
Residential	**11.0%**	**-2.5%**	**-0.4%**	**8.0%**
Small General	11.0%	-2.5%	-0.4%	8.1%
General Demand	10.8%	-3.1%	-0.5%	7.1%
Large General	10.7%	-3.3%	-0.3%	7.2%
Total Commercial	**10.8%**	**-3.1%**	**-0.5%**	**7.2%**
Small Industrial	10.9%	-2.8%	-0.2%	7.9%
Medium Industrial	10.8%	-3.1%	-0.2%	7.5%
Large Industrial	10.7%	-3.6%	-0.1%	6.9%
ELI 2PT - RTP	N/A	N/A	N/A	N/A
Total Industrial	**10.7%**	**-3.3%**	**-0.2%**	**7.3%**
Municipal	10.7%	-3.4%	-1.0%	6.4%
Unmetered	9.9%	-1.6%	-0.1%	8.3%
Total Other	**10.3%**	**-2.4%**	**-0.5%**	**7.4%**
Total ATL Classes	**10.9%**	**-2.8%**	**-0.4%**	**7.7%**
BTL				
GRLF	0.0%	0.0%	0.0%	0.0%
Mersey Additional Energy	0.0%	0.0%	-1.2%	-1.2%
LRT	0.0%	-3.8%	0.5%	-3.3%
Bowater Mersey	0.0%	0.0%	0.0%	0.0%
Total BTL Classes	**0.0%**	**-2.0%**	**0.0%**	**-2.0%**
LED SL Capital Costs	**25.4%**	**0.0%**	**0.0%**	**25.4%**
In Province Total	**10.5%**	**-2.8%**	**-0.4%**	**7.3%**
Export	0.0%	0.0%	0.0%	0.0%
Total Electric Sales	**10.5%**	**-2.8%**	**-0.4%**	**7.3%**
Misc Revenue	**2.8%**	**0.0%**	**0.0%**	**2.8%**
Grand Total	**10.3%**	**-2.7%**	**-0.4%**	**7.2%**

*Assumes traditional rate-making (not Rate Stabilization Plan).

Figure 1-2

Combined Revenue Effect of all Rate Changes in 2014*
(as Measured Against 2014 Revenues at Present Rates
Adjusted for FAM Effects from 2013)

Rate Classes	2014 GRA	2014 FAM AA	2014 FAM BA	2014 Combined Effect
ATL				
Residential	**5.3%**	**0.0%**	**-1.7%**	**3.6%**
Small General	5.3%	0.0%	-1.9%	3.4%
General Demand	5.3%	0.0%	-2.4%	2.8%
Large General	5.2%	0.0%	-3.1%	2.1%
Total Commercial	**5.3%**	**0.0%**	**-2.5%**	**2.8%**
Small Industrial	5.3%	0.0%	-2.5%	2.7%
Medium Industrial	5.2%	0.0%	-2.8%	2.4%
Large Industrial	5.2%	0.0%	-3.6%	1.7%
ELI 2PT - RTP	N/A	N/A	N/A	N/A
Total Industrial	**5.2%**	**0.0%**	**-3.1%**	**2.1%**
Municipal	5.3%	0.0%	-2.5%	2.7%
Unmetered	3.9%	0.0%	-1.7%	2.1%
Total Other	**4.5%**	**0.0%**	**-2.1%**	**2.4%**
Total ATL Classes	**5.3%**	**0.0%**	**-2.2%**	**3.1%**
BTL				
GRLF	0.0%	0.0%	0.0%	0.0%
Mersey Additional Energy	0.0%	0.0%	-2.8%	-2.8%
LRT	0.0%	0.0%	-5.7%	-5.7%
Bowater Mersey	0.0%	0.0%	0.0%	0.0%
Total BTL Classes	**0.0%**	**0.0%**	**-3.6%**	**-3.6%**
LED SL Capital Costs	**1.9%**	**N/A**	**N/A**	**1.9%**
In Province Total	**5.1%**	**0.0%**	**-2.2%**	**2.9%**
Export	0.0%	0.0%	0.0%	0.0%
Total Electric Sales	**5.1%**	**0.0%**	**-2.2%**	**2.9%**
Misc Revenue	**1.4%**	**0.0%**	**0.0%**	1.4%
Grand Total	**5.0%**	**0.0%**	**-2.2%**	**2.8%**

*Assumes traditional rate-making (not Rate Stabilization Plan).

If approved, these new rates will cover our forecast revenue shortfall of $130.3 million in 2013, and $67.5 million in 2014. We forecast a total revenue requirement of $1.352 billion in 2013, and $1.388 billion in 2014.

In each year, a few main factors are responsible for the increases.

1.1 Details of Additional Costs in 2013

1.1.1 Loss of Load and Fixed Contributions to System Costs – $53 million

Two main factors account for most of this amount. Our two largest customers, both in the pulp and paper industry, will either not operate, or will operate at reduced loads with much lower contributions to fixed system costs. Total sales to other customer classes, who now have to share the already built-in costs of our electricity system, have also declined.

NS Power has provided power to Nova Scotians for decades, first as a Crown corporation, later as a private company. Over many years, the company has built power plants, transmission lines, and distribution systems to serve customers from Meat Cove to Pubnico, and almost everywhere else in the province. As the electricity load has grown, we have added power plants, sub-stations, poles, and wires to meet demand. The cost of these facilities is spread over time and shared among all customers – much as roommates might share most of the costs of renting an apartment.

When very large customers leave the system unexpectedly, or can no longer pay their full share, fixed system costs do not decrease in proportion to the reduced electricity load. Much of the spending required to build the plants and equipment that serve all of NS Power's customers was approved years ago, together with a plan to recover those costs over many years from all customers. We have not fully recovered them yet, and we cannot mothball the affected plants and equipment because we must continue to provide a reliable power system in accordance with North American reliability standards. We also want to provide customers with the most value we can for approved investments that have already been made. We can do that most effectively by running plants at reduced capacity, rather than shutting them down altogether. That way, if our pulp and paper industry rebounds, or a new industry opens, we will be ready to meet that demand without major new investments.

Over the last six months, we have taken steps to minimize the cost of plants and equipment whose full capacity we no longer require. For example, we recently decided to run two of our four Lingan generating units on a seasonal basis, beginning in 2012.

The reduced system load we forecast for 2013 and 2014 due to the shutdown or reduced operation of our two largest customers will significantly reduce the amount these customers contribute to fixed system costs. Since revenue collected from rates has not yet fully covered the cost of the assets already on our system, our remaining customers will have to pick up a larger share of these costs beginning in 2013. This is the biggest part of the requested rate increase.

1.1.2 Rate Base and Infrastructure Additions – $39 million

This expense results from investments NS Power has made to improve service and product quality.

In the spring of 2013, NS Power will add a major new source of firm renewable energy, our biomass facility in Port Hawkesbury. We expect this project to come into service at the capital cost approved by the Board , which will make it the lowest cost, firm renewable energy available to Nova Scotians. Renewable energy projects like the Port Hawkesbury biomass plant account for a large part of our rate base additions for 2013. Maintenance and additions to other generating plants account for an additional portion of these costs. Our investments to keep transmission and distribution lines in good repair make up most of the rest of our rate base growth. Upgrades and additions for 2013 and

2014 include LED streetlights, our reliability plan, and enhancements to the transmission grid.

Planned capital investments are essential to support our overall mandate to provide safe, reliable, and affordable electricity for Nova Scotians. Last November, we submitted our 2012 Annual Capital Expenditure plan[2] to the Board. It includes 388 projects totalling $330 million. Our capital spending has grown in recent years as we have invested in renewable energy – wind farms at Nuttby Mountain, Digby and Point Tupper – and expanded our capacity to use natural gas at Tufts Cove in Dartmouth. NS Power uses about $3 billion in plants and equipment to generate and deliver power, so a substantial part of our capital plan each year goes toward maintaining and upgrading those assets.

1.1.3 Pension – $26 million

Like other companies and organizations with defined benefit pension plans, we are forecasting higher costs for the pension plan our employees have had in place for many decades. The interest rate used to calculate NS Power's future pension obligations has decreased. A lower interest rate means lower returns for the pension investments, which means we have to set more money aside to cover those future expenses.

An actuarial firm calculates our pension expense based on a number of assumptions including life expectancy, mortality rates, interest rate, salary increases, etc. The interest rate used in the pension expense calculation is known as the *discount rate*. For 2013, the discount rate used for NS Power's pension is forecast to decrease to 4.5 percent from 5.5 percent in the 2012 General Rate Application. The discount rate is a critical factor in determining how much money we have to put aside today to meet future pension obligations.

[2] NSPI 2012 Annual Capital Expenditure Plan, NSUARB-NSPI-P-128.12, November 2, 2011.

As an illustration, if NS Power's expected pension obligation one year from now were $1,000, and the discount rate were 5 percent, we would have to put away $952 today to meet that obligation (1,000 / [1+.05]). If the discount rate were 4 percent, then NS Power would have to put away $961 to meet the same obligation (1,000 / [1+.04]). The change in our actual discount rate from 5.5 percent to 4.5 percent will increase pension costs.

1.1.4 Deferrals and Regulatory Amortization - $18 million

These are approved costs that occurred in a specific year, but which we recover gradually, over a number of years, so as to spread out the impact on rates. This category has one major new component for 2013.

In the 2012 General Rate Application, we faced the problem of how to deal with the loss of load from two large customers in the pulp and paper industry. NS Power and customer representatives agreed to set rates based on a total system load of 12,647 GWh, even though the revised forecast showed a 2012 system load of only 10,925 GWh.[3] That agreement resulted in a lower rate increase in 2012 than would have occurred had we used the more accurate load forecast. Customer representatives agreed with NS Power that we should begin collecting this 2012 Fixed Cost Recovery (FCR) Deferral in 2013. The Board directed that the impact of the Load Retention Tariff applied to the Bowater mill in Liverpool should be part of this deferral.[4]

Under the traditional approach to rate setting, we propose to recover the 2012 Fixed Cost Recovery Deferral over a three-year period beginning in 2013. This results in a 2013 expense of $16.5 million. Under the Rate Stabilization Plan, we propose to let the Fixed Cost Recovery deferral continue to grow during 2013 and 2014, for recovery over an eight year period beginning in 2015, which will replace the current Section 21 Tax Deferral amount.

[3] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011.
[4] NSPI 2012 General Rate Application, Decision, NSUARB-NSPI-P-892, November 29, 2011, page 77, paragraph 217.

1.1.5 Reliability and Operating - $16 million

Most of the increase in this category will pay for improvements to reduce outages and improve response time to outages. The seasonal operation of our Lingan generators will offset this increase by $4.1 million.

Customers have told us they want more reliable service and faster restoration following outages. In response to these expectations, NS Power proposes to increase the amount of money we spend each year to reduce tree-related outages and to improve response time to outages. We forecast these system improvements to cost $8.9 million. We applied for these program improvements last year, but they were removed during settlement negotiations to reduce the total rate impact. We believe Nova Scotians still want better reliability and better storm management, so we have proposed them again.

NS Power also forecasts $5 million ($5.4M in 2013) in costs associated with running the new biomass project in Port Hawkesbury.

1.2 Details of Additional Costs in 2014

The factors driving an increase in our 2014 revenue requirement differ somewhat from those in 2013, and they reflect the situation our renewable strategy is helping us to avoid.

1.2.1 Fuel - $40 million

Almost half the total fuel increase for 2014, about $19 million, results from a forecast rise in natural gas prices and contract renewals. Biomass fuel and forward coal prices are the other major fuel cost drivers in 2014. In total, the per MWh cost of fuel is forecast to increase by $3.65 over 2013.

With respect to natural gas, several of NS Power's current gas contracts will be up for renewal, and forward prices delivered to Tufts Cove are roughly $1.50 per MWh higher than those used in the 2013 rate forecast. Coal prices are also $9 million higher than accounted for in the 2013 forecast. This change is due partly to higher future coal prices, and partly to the cost of low-sulphur coal required to meet emissions constraints. Biomass fuel adds $8 million to 2014 fuel costs, due to a forecast increase consistent with expectations in the original regulatory approval.

1.2.2 Rate Base and Infrastructure Additions - $23 million

In 2014, NS Power will continue its investment in improved product and service quality.

The main additions to NS Power's 2014 rate base will be improvements to distribution and transmission. Investments in these systems will improve reliability and allow NS Power's electricity grid to handle the new generation that will come online, much of it intermittent in nature. Our transmission and distribution systems must be ready to receive intermittent renewable electricity from new projects connected to our system, and deliver that electricity to customers.

We will continue to invest in the upkeep of NS Power's hydro system and steam plants in 2014.

1.2.3 Change in Sales Mix - $3 million

Our sales mix will continue to change in 2014, and this will increase total system costs.

The main difference between 2013 and 2014 is a change in the proportion of total energy sales purchased by the residential and commerical classes in 2014 relative to 2013.

1.2.4 Operating and Pension - $4 million

Pension costs will decrease slightly from 2013 to 2014. Operating expenses will increase less than general inflation. This category includes all increases for wages and materials in 2014.

1.3 Rate Affordability

We know Nova Scotians are frustrated with rising prices. We receive customer complaints every time we have to file a rate application. The message in those complaints is clear: Customers are concerned that electricity will no longer be affordable.

We understand this concern. That's why we work hard to keep our costs as low as possible, while ensuring safe, reliable service that meets all environmental and regulatory requirements. We have sharpened our focus on operating as efficiently as possible. Consultants regularly conduct value for money audits of our business, and invariably find it to be efficiently run. The latest performance audit, by UMS Group, can be found in OP-03.

We know our prices are higher than jurisdictions with vast hydro resources, or where governments subsidize power rates through taxes or debt. No one wants to pay more for electricity. There are Nova Scotians for whom an average monthly increase of $3.50 poses a difficult burden.

Given Nova Scotia's climate and geography, our natural advantages and disadvantages, our provincial economy, and our regulatory requirements, we are confident we have selected the best strategy to control electricity prices in the long term.

The dramatic reduction in our use of imported coal and petcoke attests to the success of this strategy. Curbing our dependence on volatile world coal markets, and shifting production to fuel-free renewables, will gradually enhance price stability. It will also reduce our environmental footprint and allow us to comply with environmental regulations.

We face unusual circumstances in Nova Scotia at this tme. The system's largest customer is currently not operating. Even if the Port Hawkesbury mill restarts, it is unlikely to contribute to fixed costs at historical levels. The system's second biggest customer is operating on a load retention tariff which produces the same result; a markedly lower contribution to fixed costs: $4 per MWh instead of $26 per MWh under the Extra Large Industrial Two Part Real Time Pricing rate. This is happening at at time when sales to other customs are not growing so we are not easily able to absorb those unavoidable fixed costs. It is these unique circumstances that have caused us to propose the Rate Stabilization Plan.

The investments required to make the transformation to a cleaner, more reliable electricity system are another driver in both years of this Application. This is not a job-creation program, but it's worth noting that it does create jobs and generate economic growth in Nova Scotia at a time when many sectors of our economy are lagging. Similar utility investments are taking place across the country. Canada's entire electrical system needs a $350-billion overhaul between now and 2030, according to the Conference Board of Canada.[5]

Energy costs are soaring around the globe. Nova Scotians see that every time they fill up the family car. Without the recent and continuing investments in basic changes to our electricity system, Nova Scotia would face near total dependence on volatile world prices for imported solid fuel, while still having to make major capital investments in air emission controls. That is simply not a sustainable long-term option for our electricity future.

[5] Conference Board of Canada Report: Shedding Light on the Economic Impact of Investing in Electricity Infrastructure, February 2012, page 1.

NS Power's long term strategy – reducing dependence on imported, high-carbon, solid fuel, and increasing our use of Nova Scotia renewables and natural gas – best serves the interests of our customers. The end result will be electricity prices that are lower and more stable than we could offer Nova Scotians if we did not change. Though this change seems difficult, not changing would be worse.

NS Power is also committed to providing customers with a view of rates over several years, so our interveners and customers understand where rates are headed. We started that process during our stakeholder consultation in the 2012 GRA, and we have continued it with this Application. Our decision to ask the Board to consider a two-year increase, rather than the traditional single-year application, is part of this commitment.

With this Application, NS Power seeks an order, effective January 1, 2013, approving:

- The 2013 and 2014 revenue requirements set out in this Application to enable NS Power to recover the reasonable costs of providing service to customers and to meet its financial obligations.

- The Rate Stabilization Plan, which provides for recovery of the 2013 and 2014 revenue requirements as follows:

    - For each customer class, an average 3 percent increase on January 1, 2013 and an average 3 percent increase on January 1, 2014, after factoring in the 2010 FAM deferral reductions in 2013 and 2014,
    - Deferral of any portion of the Board approved revenue requirement not recovered by the average 3 percent annual increases. Effectively, this will continue the 2012 Fixed Cost Recovery deferral, which will continue to grow until the end of 2014, with recovery of the deferral over an 8 year period beginning in 2015,

    - FAM adjustments, other than for the 2010 FAM deferral reductions and the 2011 FAM imbalance both of which are reflected in the 2013 FAM Balance Adjustment, will be deferred, to be incorporated into customer rates in 2015.
    - The FAM incentive will remain suspended until the end of 2014.

- The rates, charges and regulations requested in this Application.

- Changes to the Large Industrial Interruptible Rider and Load Retention Tariff Pricing Mechanism, as described in this Application.

- A change to Accounting Policy 5900 – Tax, to allow for the accounting of fixed cost recovery deferrals on a deferred tax basis, in order to align tax expense with the deferral recovery period.

- A change in the Open Access Transmission Tariff (OATT) rates described in this Application.

- Adjustments to the rates, charges, or regulations as needed to reflect decisions and directives in NS Power related proceedings or as the Board may determine in response to this Application.

- A return on common equity range held at the current 9.1 percent to 9.5 percent.

- In the alternative, recovery of the 2013 and 2014 revenue requirement using traditional rate-setting methodology as provided in the rates, charges and regulations contained in this Application.

This Application provides the Board and stakeholders with information to identify and explain key issues. NS Power looks forward to an application process that is efficient, collaborative, and well-managed. We will look for opportunities to work with the Board and stakeholders to improve the pre-hearing and hearing processes, and to resolve contentious matters in a constructive and collaborative manner, as we have successfully done in several recent proceedings.

2 NS POWER'S REQUEST – A RATE STABILIZATION PLAN

The circumstances outlined in the Introduction describe a storm of pressures on the cost of making electricity in Nova Scotia. We believe these extraordinary pressures are best tackled through a creative solution that will ease the burden on customers – giving homeowners and businesses time to adjust to rising prices – while providing NS Power with adequate cash flows and a mechanism for full, though partially delayed, cost recovery.

Our proposed solution – a two-year Rate Stabilization Plan – is outlined below. It is not the traditional way of setting rates, but these are not ordinary times. We believe the current circumstances require a better way for customers.

A traditional General Rate Application would include detailed forecasts for the test year. This Application contains all that information for the year 2013. In addition, because we believe the current unusual circumstances demand a multi-year approach, we have included equally detailed forecasts for the year 2014. We have worked on this analysis for many months, as we do for every rate case, and the numbers are available for review and debate as part of the regulatory process. If stakeholders prefer the traditional route, our evidence includes all the numbers needed to calculate appropriate annual rate increases for the next two years. But they are big numbers, created by unusual circumstances, and that is why we think a Rate Stabilization Plan, to smooth cost adjustments over time, is a better option.

In 2013, the forces pushing up the cost of producing electricity in Nova Scotia include the loss of load caused by the downturn in the pulp and paper industry; the resulting loss of contributions that industry traditionally made to the fixed costs of our electricity system; additions to the rate base including new plant and equipment for generating renewable energy to meet Nova Scotia's renewable energy requirements; and pension costs that are rising for NS Power just as they are for all employers with a traditional defined benefit pension plan. In 2014, the pressures include higher fuel costs, especially for natural gas, coal and biomass; and additions to the rate base for improvements to our transmission and distribution systems to enable them to handle greater numbers of intermittent renewable energy sources.

Traditionally, an application to increase power rates considers only a single year of forecast costs and revenue. This can pose problems for anyone needing to make long term decisions about business investments, capital purchases, or even the kind of heating system to install in a house. It's equally difficult for NS Power's planning needs.

A one-year view presents even greater problems when major changes – such as the dramatic load reductions we have experienced from our two largest customers – suddenly threaten to overtake to the electricity system. Changes of that scale and suddenness can produce a price spike in one year, followed by a moderation in rates the next as the system adjusts.

With so many pressures bearing down on Nova Scotia's electricity system over the next few years, we believe there is a better way to adjust rates: a multi-year approach.

In a period of rapid change, it is important to have a clear view of the future. This is especially important in the electricity business. NS Power and many of our customers need to make long-term investments and decisions based on multi-year plans. By looking at cost factors beyond the next year, we can better align rates and cost recovery with the needs of both customers and the utility, in a way we can't do with the traditional year-by-year approach. A multi-year approach helps the utility, customers, and the Board assess whether cost factors need to be addressed all at once, or whether they can be factored in gradually, in a way serves all parties fairly and efficiently.

We know rate increases create problems for our customers. They add to the cost of running households and businesses. NS Power works hard to keep prices as low as possible, and to make price changes manageable for our customers. That's why we believe, in this time of transformation and capital investment, a multi-year plan offers a better solution for customers than the traditional way of resetting rates.

A general rate application has two stages:

1. The first stage is to **establish the revenue requirement** for the year that serves as the “test year” for the application; this process determines the total forecast cost of delivering all aspects of electricity service to the customers of NS Power.

2. The second stage is to **calculate the rates** needed to recover the approved revenue requirement established in stage one; this stage determines when costs will be recovered; the mechanisms used to recover them (whether through traditional rates or, more recently in Nova Scotia, rate riders), and how the approved costs are allocated among various customer classes.

In this Application, NS Power is seeking UARB approval of a two-year rate plan, with stable overall net increases of 3 percent per year. The first stage of this General Rate Application is the same as in any previous GRA, except that NS Power has forecast the revenue requirement for each of the next two years instead of the traditional single year approach.

NS Power forecasts a revenue requirement of $1.352 billion in 2013, and $1.388 billion in 2014. As in any other rate case, NS Power must explain and support these forecasts. That explanation and support is contained in the pages of this Application, in the Direct Evidence we will present, and in the data contained in the Board-directed standardized filing. The evidentiary disclosure process, an important part of any rate case, will produce even more evidence. Except for our inclusion of a two-year forecast, this is the traditional approach to Stage One of a General Rate Application, establishing the total revenue required by Nova Scotia’s electricity system.

In stage two of this Application, determining the rates needed to recover the revenue requirement, we propose a non-traditional approach. We do so for two reasons:

- To **give the Company and customers time to adapt** to rapidly changing circumstances, and

- To **protect customers from the rate spikes** that would otherwise result from the sudden loss of the contributions to fixed costs by the pulp and paper industry and from the rapid transformation to new renewable energy at a time when we can't yet retire traditional generating plants.

To help adjust to these changes, NS Power is seeking lower rates than we would need to immediately recover all our forecast costs. We also propose to continue deferring the recovery of fixed costs related to the loss of pulp and paper load contributions. By this Application, NS Power seeks UARB approval of a two-year rate plan, with stable net increases of 3 percent per year including adjustments to the Fuel Adjustment Mechanism involving the 2010 FAM Deferral and the 2011 imbalance as reflected in the estimated FAM 2013 Balance Adjustment in Appendix P, Attachment 2.

We call this the *Rate Stabilization Plan*.

The Rate Stabilization Plan calls for consistent, moderate rate increases on January 1, 2013, and January 1, 2014. Those increases will cover a portion of the increased costs forecast in each of the next two years. The remaining revenue requirement will be deferred for future recovery. The amount of the deferral will be calculated separately for each class of customer, so the across-the-board 3-percent increase will result in deferrals that accurately reflect the specific cost of serving each class of customer.

The mechanism for such a deferral already exists. The 2012 Fixed Cost Recovery deferral, which accommodated uncertainty about the pulp and paper load, was agreed to by customer representatives and approved by the Board as an outcome of the 2012

General Rate Application.[6] We propose a simple extension of the Fixed Cost Recovery deferral for another two years. This will provide necessary relief for customers by allowing us to limit rate increases to a more manageable 3 percent. We expect the amount of the deferral to be similar in size to the fuel deferral proposed by customers and approved by the UARB in the 2010 FAM process.[7]

The 3 percent adjustment will incorporate forecast decreases connected to the phase-out of the 2010 FAM Deferral. These scheduled FAM decreases will be redirected to help cope with the exceptional cost pressures facing electricity production over the next two years. These include costs related to new renewable energy, including wind energy purchased from independent power producers, NS Power's own investments in the Port Hawkesbury biomass plant, and changes in taxes relating to earlier wind energy projects at Nuttby Mountain and in Digby. In effect, this redirects costs customers are currently paying for fuel to pay for renewable energy during this period of change.

The Fuel Adjustment Mechanism will continue operate, but additional AA and BA changes in 2013 and 2014 fuel costs will be deferred within the FAM until the Rate Stabilization Plan ends. Since the FAM is class-specific, NS Power will be able to track both fuel and non-fuel costs separately for each customer class. That enables us to attribute deferred amounts to each customer class based on cost-of-service principles, even though the plan applies an across-the-board rate increase to all customers.

The 2010 FAM process made it apparent that our stakeholders prefer a smooth and predictable approach to rate changes. Customer representatives and the Board have accepted in principle the option of deferring the recovery of costs, including the cost of financing the deferral itself. From NS Power's perspective, deferrals can be acceptable when applied in a measured manner that does not jeopardize the future interests of customers or the financial health of the utility. To protect the financial health of the

[6] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011, and NSPI 2012 General Rate Application, UARB Order, NSUARB-NSPI-P-892, December 21, 2011.
[7] NSPI 2011 FAM AA BA Application, UARB Order, NSUARB-NSPI-887(2), December 17, 2010.

utility, it is important that the recovery of any deferral be approved when the deferral mechanism is established. This will assure financial markets and analysts that the timing and method of recovery has been accepted by customers and approved by the Board.

A good example of a deferral that helped both customers and NS Power is the Section 21 Tax Deferral. The Board approved this deferral to allow gradual recovery of a significant tax liability resulting from an unanticipated Canada Revenue Agency ruling.[8] NS Power paid the tax bill outright, but the amount was too large to incorporate into rates for recovery in a single year. The Section 21 Tax Deferral provided for recovery over eight years ending in March 2015.

In the current situation, NS Power believes a modest, short-term deferral of increased expenses is an appropriate way to stabilize rates for customers over the next two years. We propose to begin recovering the deferred costs in 2015, just as the Section 21 Tax Deferral expires. By timing the deferral this way, and if the deferred amount is less than $110 million, we will be able to recover it in full over eight years, with no change in rates. In effect, as soon as we finish collecting the Section 21 Tax Deferral, we will replace it with an eight-year recovery of the Fixed Cost Recovery deferral.

By the time 2015 arrives, there will be other cost increases and adjustments to deal with. At some point, rates will need to reflect the loss of pulp and paper load. The Rate Stabilization Plan will help for the next two years, but eventually we must ensure that our rates reflect reality. By delaying the adjustment to the loss of load until 2015 we allow more time for pulp and paper load to return, or new load to appear. If that happens, it will help offset the impact of the eventual adjustment. At the end of this period of adjustment, rates will reflect actual load and costs. The Rate Stablization Plan allows us to achieve that outcome with manageable rate increases, set in a manner that is predictable and responsible.

[8] 2005 NSPI General Rate Application, UARB Decision, NSUARB-NSPI P-881, paragraphs 326-328.

Appendix P contains the detailed calculations and supporting documents respecting NS Power's requested rates and deferred revenues associated with its Rate Stabilization Plan.

The Rate Stabilization Plan has the following elements:

1. On January 1, 2001, and again on January 1, 2014, overall rates for all customer classes will increase by 3 percent. This two year period will constitute the *Rate Stabilization Period*.

2. The 3 percent rate increases in 2013 and 2014 will be net of any adjustments to the FAM. Recovery of the 2010 FAM Deferral is set to expire during the Rate Stabilization Period, partially in 2013 and completely in 2014. This would ordinarily have a positive impact on rates, that is, it would help lower them. In this case, however, we will hold the overall rate increases at 3 percent by using the extra room created by the expiry of the 2010 FAM Deferral to help pay for the new renewable energy we are adding to the system. In this way, conceptually at least, revenue that previously paid for carbon-based generation will now pay for the new renewable generation that is transforming our electricity system.

3. Any portion of the Board-approved revenue requirement not recovered by the 3 percent annual increases will be deferred. Any change to the revenue requirement resulting from the UARB decision will affect the amount of the deferral, not the 3-percent annual increase, in order to attempt to match the Section 21 Tax Deferral in rates.

4. An eight-year recovery beginning in 2015 will allow recovery of the deferral to replace the expiry of the Section 21 Tax Deferral. To offset this rate reduction, the deferral must be no more than $110 million.

5. The Base Cost of Fuel (BCF) will be reset in each year as part of this Application, and there will be no further FAM-related rate changes during the Rate

Stabilization Period other than those proposed in Appendix P. However, the FAM will continue to operate for the purpose of oversight, accounting, reporting, and auditing. With no FAM adjustments, there may be no requirement for another FAM hearing until the Fall of 2014.

6. Any FAM Annual Adjustments (AA) or Balancing Adjustments (BA) calculated during the Rate Stabilization Period, whether it is an under-recovery or an over-recovery, will be deferred to 2015. This new FAM-related deferral (or over-recovery) must be tracked separately from the Fixed Cost Recovery deferral, because fuel costs and non-fuel costs are treated differently in the Cost of Service Study for NS Power's customer classes.

7. NS Power tracks fuel and non-fuel costs, and deferred amounts in both categories, separately for each customer class. We will track the Fixed Cost Recovery deferral and the 2013 and 2014 FAM AA and BA adjustments by customer class. If the FAM results for 2013 or 2014 would have caused a reduction in FAM rates, customers will receive the benefit of that reduction through a deferred fuel credit for their specific customer class. If they would have caused rates to go up, customers will have a deferred balance. Either way, the deferred amounts will be incorporated into customer rates in 2015.

8. The FAM incentive mechanism will not operate during the Rate Stabilization Period, since load levels are uncertain and there will be no further opportunity to adjust fuel rates to reflect the latest forecasts. This is the approach the parties adopted when they agreed to create the FCR deferral in the 2012 General Rate Application.

9. In this Application, NS Power proposes to maintain the range for regulated return on equity (ROE) at its present level, which was just lowered in the 2012 GRA. The current range is 9.1 to 9.5 percent. Revenue requirement is established using a 9.2 percent target. NS Power asks that the same mechanism that applies to the

Section 21 advanced amortization amount (AAA) Mechanism[9] also apply during the Rate Stabilization Period, so that any earnings above 9.5 percent over the cumulative, two-year period will be returned to the benefit of customers by reducing the outstanding amount of the Fixed Cost Recovery deferral. This will ensure that any operating cost efficiencies, or rate-making assumptions that prove wide of the mark and cause a higher-than-expected revenue requirement, will benefit customers rather than increase shareholder earnings. This provision will serve as a cap on NS Power's cumulative earnings during of the Rate Stabilization Period.

10. NS Power proposes to apply the 3 percent rate increase equally to all customer classes, an approach similar to that taken in the 2009 General Rate Application Settlement Agreement. This will simplify application and understanding.

11. During the Rate Stabilization Period, NS Power will update its Cost of Service Study. When we begin to collect the Fixed Cost Recovery deferral, along with any FAM deferral or rebate, rates will be aligned so that each customer class contributes the amount determined by the Cost of Service Study then in place.

12. NS Power will need the Board to allow the Company to account for these deferrals on a deferred tax basis, in order to align tax expense with the deferral recovery period. This is the best accounting approach for customers. It is how accounting presently works for the FAM.

13. Alternatively, NS Power could, at the request of customers or direction of the Board, apply the Cost of Service Study now, so as to establish new rates for each customer class according to traditional cost of service principles, in such a way as to achieve a 3 percent increase in overall revenue. In that case, customer classes would experience various rate increases, rather than a consistent, across-the-board

[9] UARB Order Approving ROE Settlement Agreement, NSUARB-NSPI-P-888(2), January 20, 2010.

> increase of 3 percent. Customer representatives would have to agree, or the Board would have to decide, which cost categories will be adjusted to achieve the overall 3 percent increase. We think this approach is unnecessarily complicated, given the relatively brief period of transition, the amounts involved, and the prospect of a new Cost of Service Study during the planning period. NS Power has not undertaken these calculations because our strong preference is that the Rate Stabilization Plan be based upon the same, equitable rate increase for all customers during this transition period.

On April 27, 2012, the Board received an Application to approve a new Load Retention Tariff proposal for the Port Hawkesbury mill (Matter M04852). As part of that Application, NS Power asked the Board to approve the partial extension of the Fixed Cost Recovery deferral. In the context of that Application, the extension of the Fixed Cost Recovery deferral will provide a convenient vehicle for NS Power to apply any fixed cost contribution received as a result of the mill's operation. The multi-year Rate Stabilization Plan is an extension of that request.

NS Power is committed to supporting the successful operation of the mill, so it can make a significant contribution to fixed cost recovery. Fixed cost contributions will benefit customers in the next two years by reducing the FCR amount. The Rate Stabilization Plan will provide two years of stability for all customers, while giving the mill a chance to become profitable and make the largest possible contribution to the fixed costs of the system.

For NS Power, the Rate Stabilization Plan allows time for the system to adjust to the new reality of the pulp and paper load, while bringing renewable energy into the generation mix.

If stakeholders determine they would rather not have a multi-year plan that includes a deferral as a necessary component, or if the Board declines to approve the Rate Stabilization Plan, this Application provides all information needed to support the traditional approach to changing general electricity rates (without adding to deferrals), while still allowing rates to be set for two years. The Rate Stabilization Plan is NS Power's preferred option, but NS Power requires rates that provide for recovery of the revenue requirement established by the Board, whether a deferral is part of the final approval or not. In other words, NS Power believes the only reasonable alternative to the Rate Stabilization Plan is to set rates according to the traditional approach, with no deferral.

During this period of change and unusual cost pressures, our Company and our customers will both benefit from stable and predictable rate changes. Just as we did last year, NS Power will engage stakeholders and customer representatives in a transparent manner about these costs and how best to recover them in customer rates.

Nova Scotia Power and our customers have two choices. We can absorb the full impact of the unique combination of forces pushing rates up in just one or two years, or we can give customers time to adjust with a Rate Stabilization Plan that sets out a prudent, responsible means of coping with these unique circumstances over a longer, but still reasonable, period of time. We believe the latter is the more sensible option.

We know that back-to-back increases of 3 percent will still be a burden for many Nova Scotians. We wish that wasn't the case, but we know it will be.

We can't fully shield customers from the pressures on electricity prices. We firmly believe this solution is much better for all customers than the alternative.

It will give us time to see how the pulp and paper industry progresses.

It will give us time to adjust to the changes in how we generate electricity.

It will help our customers manage the increases in electricity costs.

3 LOAD FORECAST

3.1 Overview

Customer demand for electricity affects the cost of running Nova Scotia's electricity system in two ways:

- Total demand for electricity affects NS Power's variable operating costs, especially for fuel.

- Peaks in demand determine the amount of generating capacity we need, and thus our fixed costs over the long-term.

This section of the Application explains our forecast for both: total energy requirement, and peak demand from month to month. The load forecast plays an essential part in determining future costs, and helps us allocate costs among different types of customers, a process detailed in Costs and Rates Section.

We forecast the following net energy demand in Nova Scotia over the next two years:

- 2013 10,721 GWh
- 2014 10,709 GWh

These amounts fall well below the 2012 forecast of 12,647 GWh net energy demand.[10] The main cause of the decline is our assumption, for the purpose of our load forecast, that the paper mill in Port Hawkesbury will not operate in those years. The Port Hawkesbury mill was our largest customer and has historically consumed approximately 1,500 GWh of electricity per year. A second, much smaller factor in the decline is the province's

[10] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011, Section 8 Load Forecast, pages 118-132.

current unsettled economic climate, which we expect to cause a further 400 GWh reduction in demand from the 2012 GRA Forecast.

On April 27, 2012, the Board received an Application to approve a new Load Retention Tariff for the Port Hawkesbury mill (Matter M04852). We are actively involved in trying to make that happen in a way that benefits all our customers. Although the proposed purchase faces some hurdles, we share the hope and expectation that the plant will eventually operate.

At the time that our forecasts were prepared, the future of the mill remained uncertain. As a result, our forecast reflects the view that the mill will not contribute to system fixed costs in 2013 and 2014.

Even if the mill re-opens in 2013 or 2014, it appears likely that only one of its two paper machines will operate. The Application presently before the Board is based upon the mill taking incremental energy so that no customer is at risk to pay any of the variable cost of the mill's load. Further, the proposal allows for a contribution to system costs of at least $2/MWh on a tax-efficient basis. There is an opportunity for a greater contribution depending upon the profitability of the mill. The proposal for the mill calls for every penny of that contribution to be directed to the benefit of customers by reducing the Fixed Cost Recovery deferral. Therefore, to the extent the mill operates, there should be no negative consequence on customers, and the positive contribution will directly benefit customers. For the purpose of the load forecast, the mill load can be isolated and treated as if it is essentially not operating.

The loss of the pulp and paper industry load affects customers in a positive manner with respect to fuel costs, but in a negative manner with respect to responsibility for the fixed costs of the system. This remains true under the proposed new rate structure for the Port Hawkesbury mill because the mill will use incremental energy and other customers will have no responsibility for the fuel and other variable costs the mill imposes on the system. On the other hand, the fixed costs of the plants and equipment used to generate and distribute electricity will not decrease enough to compensate for the lost revenue caused by the drop in load – and those fixed costs will be spread among fewer customers.

For 2013, the net impact of the reduced load, considering both mills and other cutomer groups, is a revenue shortfall of $53 million, out of our total requested revenue requirement increase of $130.3 million.

The parties to NS Power's 2012 General Rate Application recognized this uncertainty and agreed that the company should recover the fixed costs required to provide all customers with electricity from the customers that remain on the system. The 2012 GRA Settlement Agreement stated:

> 2. Due to the indefinite shut down and creditor protection of New Page Port Hawkesbury, load for this customer may not materialize in 2012 at the CBL level included in rates. The future of Bowater Mersey Paper Company is also uncertain, in light of the evidence in the Load Retention Tariff (LRT) application. Setting rates that include revenue from NPB will not provide the utility the opportunity to recover its costs and would therefore not be just and reasonable. Therefore, in order to maintain the lowest reasonable rate increase by setting rates to include NPB load, the parties agree that:
>
> a. The NPB load will be based upon the levels forecast in the May 13 filing, and the forecast non-fuel contribution from these customers will be calculated as the forecast total revenue from all load of these customers less the forecast BCF revenue for these customers.
>
> b. Any amount of unrecovered NPB contribution to non-fuel costs net of non-fuel variable O&M costs, will be deferred for later recovery from all customers beginning in 2013.[11]

In other words, the settlement provided that rates would be set as if NewPage and Bowater were both operating at expected levels. In the event they did not operate, or

[11] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011, page 1, paragraph 2.

operated at reduced levels, and therefore did not contribute to fixed system costs, the revenue shortfall as compared to the forecast contribution from these customers would be deferred for recovery from all customers beginning in 2013.

The Board approved the Settlement Agreement and acknowledged the future uncertainty surrounding this load.

> The GRA Agreement also provides some stability to the ratepayers in the face of uncertain economic conditions presently existing in Nova Scotia. As noted by counsel for Avon, the deferral clause in the GRA Agreement offers "a mechanism to address the uncertainty surrounding the indefinite shutdown and creditor protection of NewPage" and, for that matter, the precarious situation of Bowater. Since the negotiated revenue requirement is based on the NSPI Application load forecast, the ratepayers benefit from the deferral of an immediate marked increase in rates. Thus, any recovery of lost NPB contributions to non-fuel costs (net of non-fuel variable O&M costs) is deferred to 2013. This deferral mechanism provides some stability for the Utility and ratepayers despite the uncertain future of the NewPage and Bowater mills.[12]

Electricity rates are a function of the amount of money needed to run the system (the revenue requirement) and the total amount of electricity used in Nova Scotia homes and workplaces (the system load). If the revenue requirement remains constant from year to year, but the system load decreases, customer rates will increase. This is a key driver for increased rates proposed in this Application for 2013 and 2014. In addition to the loss of the Port Hawkesbury mill load, the Load Retention rate approved as part of the 2012 GRA Decision allows Bowater to contribute a reduced amount to fixed costs. Due to this, the fixed system costs that would have previously been recovered from Bowater, must be recovered from remaining customers.

NS Power actively manages its costs as detailed in the Operating Costs section and supported by its benchmarking studies in Appendix A. The reality is many of our costs

[12] NSPI 2012 General Rate Application, Decision, NSUARB-NSPI-P-892, November 29, 2011, page 18, paragraph 35.

are fixed. The depreciation rates for our plant investments and regulatory amortizations are previously approved by the UARB and fixed. Much of our operating costs are fixed as we require a base complement of labour and materials to maintain a safe and reliable service.

In the short term, a sudden load reduction will increase the amount to be recovered from other customers. Over time, as plant assets are depreciated this burden is reduced, as the costs of running the system will be lower with lower load.

The load forecast breaks down the expected provincial load into three main categories (residential, commercial and industrial). It divides each of these into the various customer sales classes. The 2012 Load Forecast Report, provided in SR-02, provides this breakdown in greater detail.

Key points of the 2013 and 2014 load forecast include:

- Overall sales of electricity within Nova Scotia, which had little growth over the previous five years, dropped by 2.1 percent in 2011, due mainly to the closure of the province’s largest paper mill for the last three months of the year. We expect sales in 2013 to be 10 percent lower than 2011, mainly due to our assumption, for load forecast purposes, that the Port Hawkesbury mill will not operate in future years. Aside from the effects of the large paper mills, the remaining load is anticipated to diminish slightly (-0.3 percent) from 2011 to 2013. We predict sales in 2014 to decline slightly from 2013, because Efficiency Nova Scotia’s Demand Side Management (DSM) programs will offset any growth.

- We forecast residential sales in 2013 to decline slightly (0.1 percent) from 2011 levels, due to economic conditions, increased prices, and the ongoing influence of DSM programs. For the same reasons, we expect commercial sales in 2013 to decrease by 1.5 percent from 2011. The big drop is in industrial sales. In 2013, we expect industrial sales to fall by 1,129 GWh, or 32 percent, due mainly to the closure of the Port Hawkesbury mill.

- In 2014, we expect residential and commercial sales to decline slightly, but we expect a mild recovery in industrial activity will produce 0.7 percent growth in that sector.

- NS Power assumes that future Efficiency Nova Scotia DSM programs will continue to reduce the electric load forecast, and based on estimates available at the time of forecast, assumes program targets of 133 GWh in both 2013 and 2014.

- In the winter of 2012/2013, we expect demand to peak at 2,098 MW, well below recent annual peaks. The forecast drop in peak demand is due mainly to changes at the province’s large paper mills, where we expect demand to fall by more than 175 MW. Our winter 2012/2013 forecast is 70 MW below the peak demand of 2,168 MW in the winter of 2010/2011, when temperatures ranged as low as minus 13°C. It is 140 MW below NS Power’s all-time record peak of 2,238 MW, set in January 2004, when temperatures fell to minus 18°C.

- In the winter of 2013/2014, we forecast a peak demand of 2093 MW, slightly lower than 2013. Again, the main reason is reduced industrial demand from pulp and paper plants.

The following sections explain how we develop the load forecast.

3.2 Models

As in prior years, our load forecast uses surveys, econometric data, information supplied by customers, and informed assumptions about the economic, demographic, and technological environment in the forecast period. We model the residential, commercial, and industrial components of total electricity demand, and allow for line losses associated with moving electricity from generating stations to customers. The 2012 Load Forecast Report, provided in SR-02, describes our current procedures in detail.

Figure 3-1 displays the annual year-ahead forecast and actual in-province load, and shows the variance between the two. The table shows the decrease in overall load since 2007, due to conservation and efficiency programs (DSM), the economic downturn, and major load reductions by the largest industrial customers. Actual results also reflect the impact of weather effects. The 2012 Load Forecast Report in SR-02 sets out the econometric model equations and regression statistics.

Figure 3-1

NS Power In-Province Energy Forecast Accuracy						
Year	Forecast Load (GWh)	Actual Load (GWh)	Variance			
			Delta (GWh)	Actual / Forecast (%)	Weather-Adjusted Delta (GWh)	Weather-Adjusted Actual / Forecast (%)
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
2011*	12,444	11,908	-536	-4.3	-435	-3.5

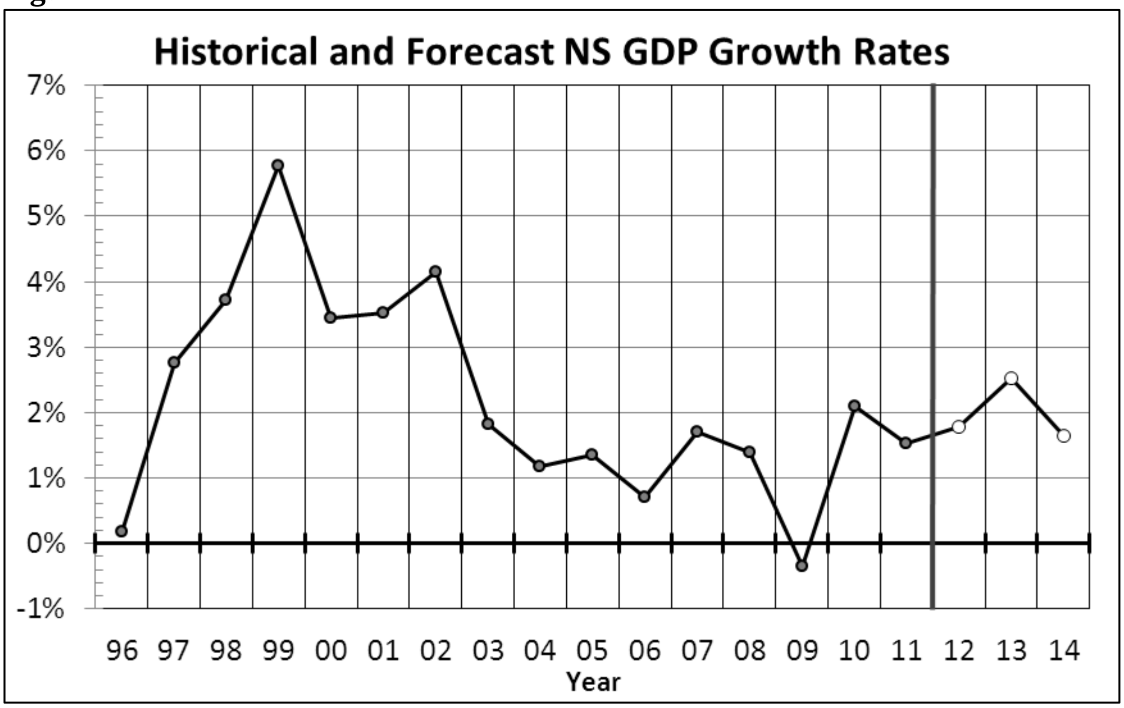
*2006, 2009 and 2011 saw shutdowns at major industrial customers.
**The 2006 heating season was much warmer than average.

3.3 Economic Indicators

Economic indicators such as Gross Domestic Product (GDP) play a major role in the load forecast models. The residential forecast model employs consumer goods consumption as an economic indicator, the commercial model uses provincial GDP for service industries, and the industrial sector employs an indicator based on the provincial GDP for manufacturing.

NS Power uses Nova Scotia economic indicators and demographic data from the latest available Conference Board of Canada economic forecast (November 2011).[13] Figure 3-2 shows historical and projected GDP growth rates. The Conference Board of Canada forecasts the Nova Scotia GDP to grow by 2.5 percent in 2013 and 1.6 percent in 2014.

Figure 3-2



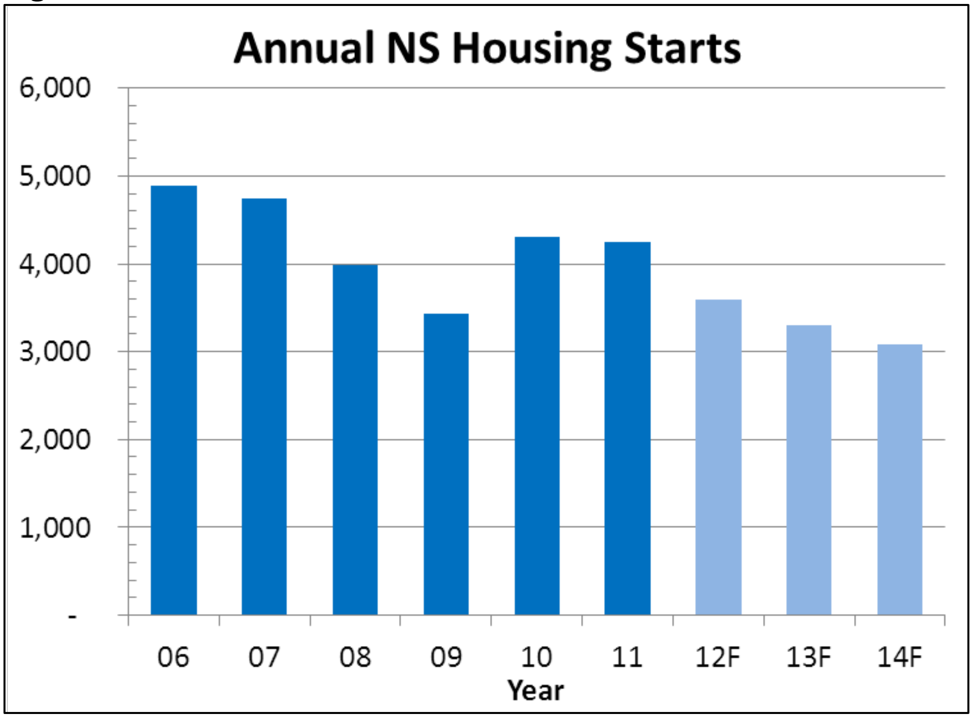
Source: The Conference Board of Canada

The Conference Board forecasts GDP for service industries to increase by 1.8 percent in 2013, and 1.6 percent in 2014. Annual growth in the service sector has averaged 1.8 percent over the last five years. The Conference Board expects sales of consumer goods

[13] The Conference Board of Canada, "Provincial - data - November 24, 2011", eData, http://www.conferenceboard.ca/e-Data/default.aspx.

to grow by only 1.0 percent in 2013, and 0.8 percent in 2014. Consumer sales averaged 1.4 percent annual growth over the last five years. As shown in Figure 3-3, The Conference Board forecasts only 3,307 total housing starts in 2013 and only 3,086 in 2014, well below the average 4,147 starts over the last 5 years.

Figure 3-3



Source: The Conference Board of Canada

3.4 System Requirement

The total energy requirement is the sum of residential, commercial, and industrial sales, plus export sales and associated losses. The total requirement grew by an average of 0.4 percent per year from 2003 to 2008, and then dropped 3.8 percent in 2009 due to the economic circumstances. It grew by 0.6 percent in 2010, and then dropped again by 2.0 percent in 2011, due to reduced load at major paper mills.

In 2013 and 2014, we expect industrial demand to remain soft. In the commercial and residential sectors, we expect that downward pressure on demand due to Demand Side

Management (DSM) programs that will offset the modest upward pressure caused by forecast improvement in economic conditions. The result is a slight decline in overall residential and commercial demand in the 2013 and 2014 forecast.

As shown in Figure 3-4, we forecast a total energy requirement (including exports) of 10,751 GWh in 2013, and 10,740 GWh in 2014.

Figure 3-4

Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Line Losses (GWh)	Net In-Province System Requirement (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
2011	4,346	3,310	3,535	717	11,908	-2.1	9	11,917	-2.0
2012F	4,384	3,279	2,437	737	10,839	-9.0	136	10,975	-7.9
2013F	4,340	3,259	2,406	716	10,721	-1.1	30	10,751	-2.8
2014F	4,323	3,238	2,423	725	10,709	-0.1	30	10,740	-0.1

Figure 3-5 below shows the total requirement for 2013 and 2014 relative to past years.

Figure 3-5

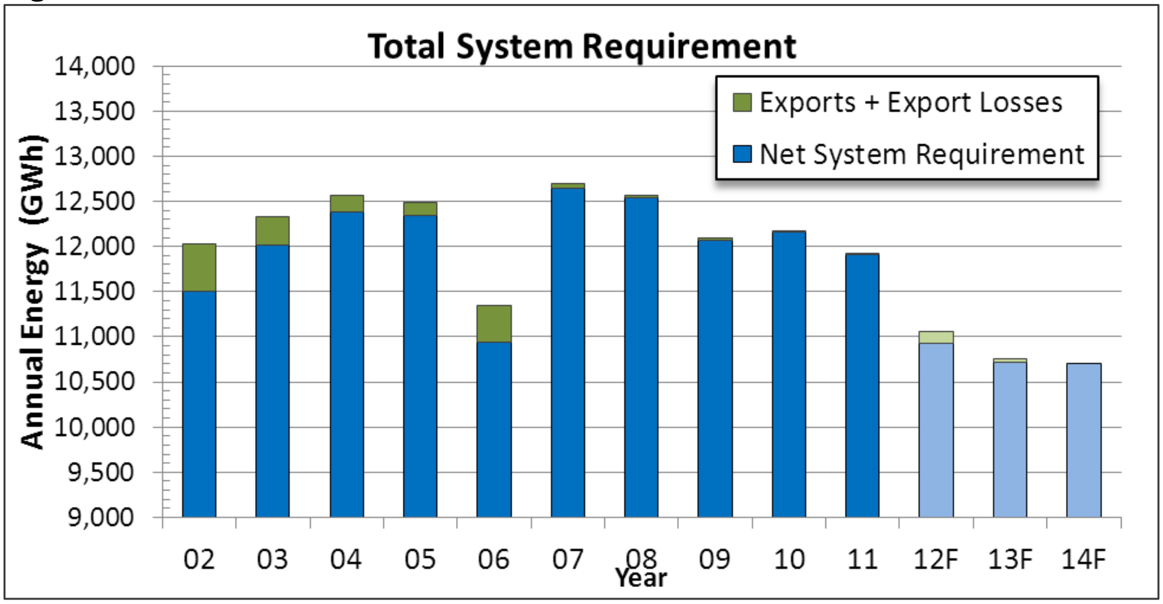
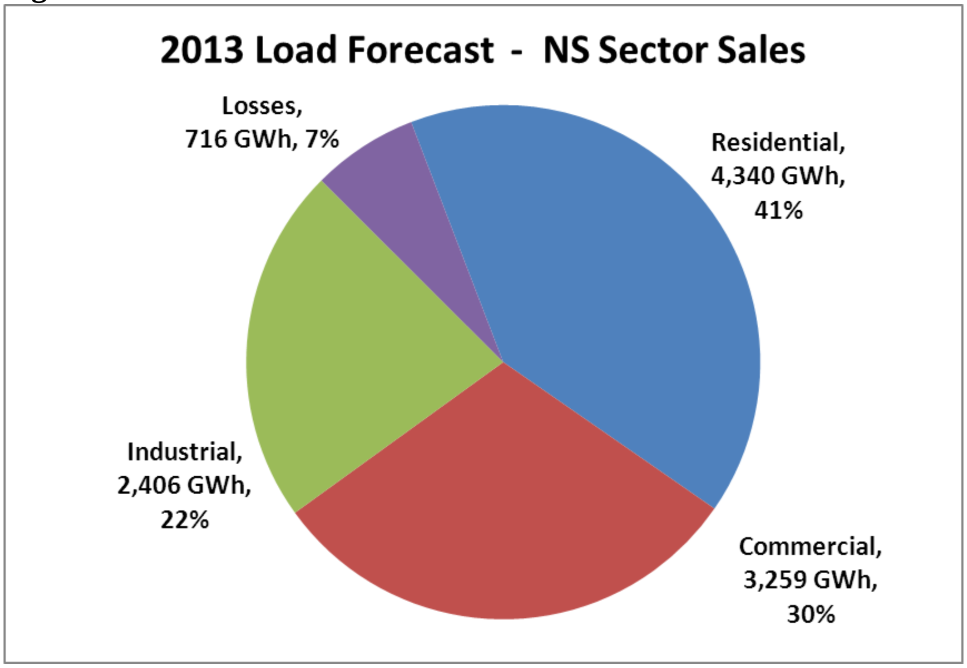


Figure 3-6 below shows the contribution of the major customer groups and of line losses to the 2013 load forecast.

Figure 3-6



The following sections describe each segment in more detail.

3.4.1 Residential Sector

The residential sector includes year-round and seasonal households, non-commercial farm use, and residential customers served by municipal utilities. We expect 2013 residential sales to make up 40 percent of in-province energy requirements. This is a higher proportion than in recent years due to the reduced load in the industrial sector.

The residential forecast uses an econometric model that incorporates a variety of information about household patterns. For example, we estimate household appliance load based on average appliance use, market penetration by various types of appliance, average age of appliances, efficiency improvements, and growth in the number of customers. We estimate residential space heating load based on the number of electric heat customers and predicted heating degree-days for the year. The predicted heating degree-days are based on a 10-year average of the annual heating degree-days, stepped forward each year to capture the changes due to the observed warming trend in our weather.

Space heating and water heating are major elements in total residential electricity use. Our model estimates the market penetration of electric heat based on the relative price of electricity and heating oil, using both recent and forecast commodity price changes. For 2013 and 2014, the model predicts that approximately 31 percent of Nova Scotia residential customers will use electric space heating, up from 29 percent in 2010. Sixty-one percent will use electric hot water.

Our residential econometric model uses sales of consumer goods in Nova Scotia as a primary economic indicator. The Conference Board of Canada predicts that these sales will grow at a slower rate in 2013 and 2014.

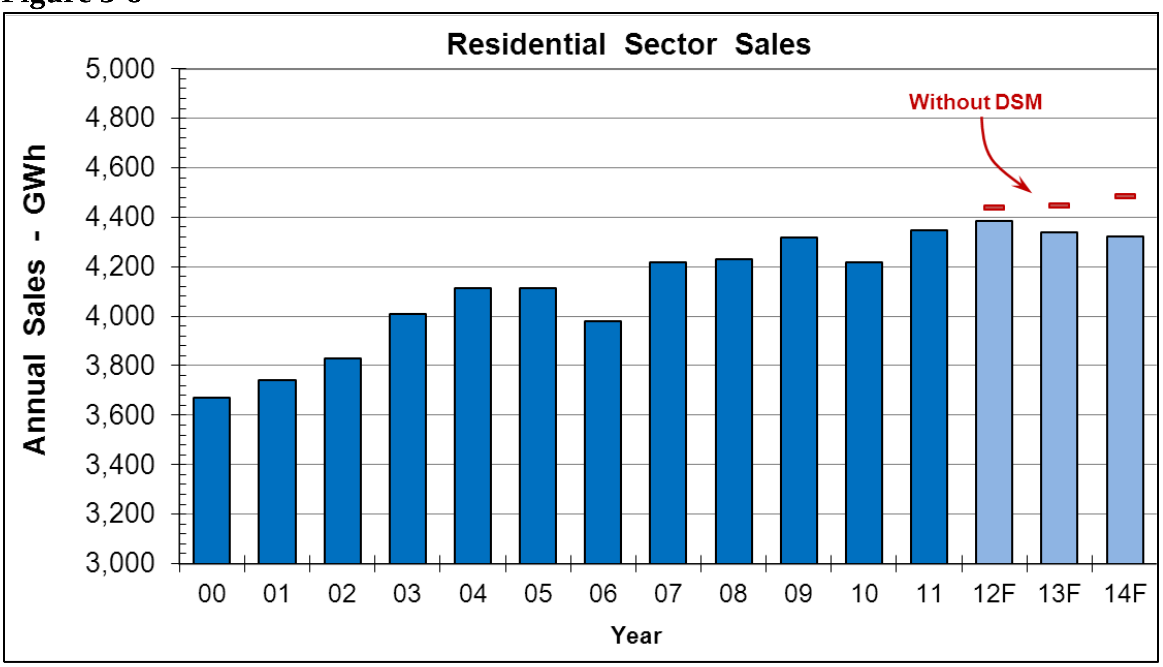
Figure 3-7 shows the historical accuracy of our forecasts for this sector, without adjustment for weather effects.

Figure 3-7

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
2011	4,341	4,346	0.1

The chart below shows the recent trend in residential sector energy sales.

Figure 3-8



Residential load has grown at an average annual rate of 1.8 percent over the last five years or 1.4 percent when adjusted for weather effects.

3.4.2 Commercial Sector

The commercial sector includes restaurants, theatres, retail stores, banks, office buildings, malls, schools, street lights, and traffic lights. In 2013, we expect commercial sales to make up 30 percent of our in-province energy requirement. As with residential, this is a larger proportion than in the past, due to the reduced load in the industrial sector.

Electricity use by universities, hospitals, and large firms with commercial operations in Nova Scotia varies with the strength of the provincial economy and the level of government expenditures. The load forecast for the sector uses an econometric model that includes historic commercial load levels, the NS GDP for service industries, and heating degree-days. We also survey customers in the Large General rate category, and include individual forecasts for them in our commercial load forecast.

Commercial load grew at an average annual rate of 0.6 percent over the last five years, but this five-year average masks a slight decline in the last four years due to the depressed economic conditions in that period. When corrected for weather effects, the last four years have had no growth.

Figure 3-9 shows the historical forecast accuracy for this sector, without adjustment for weather effects.

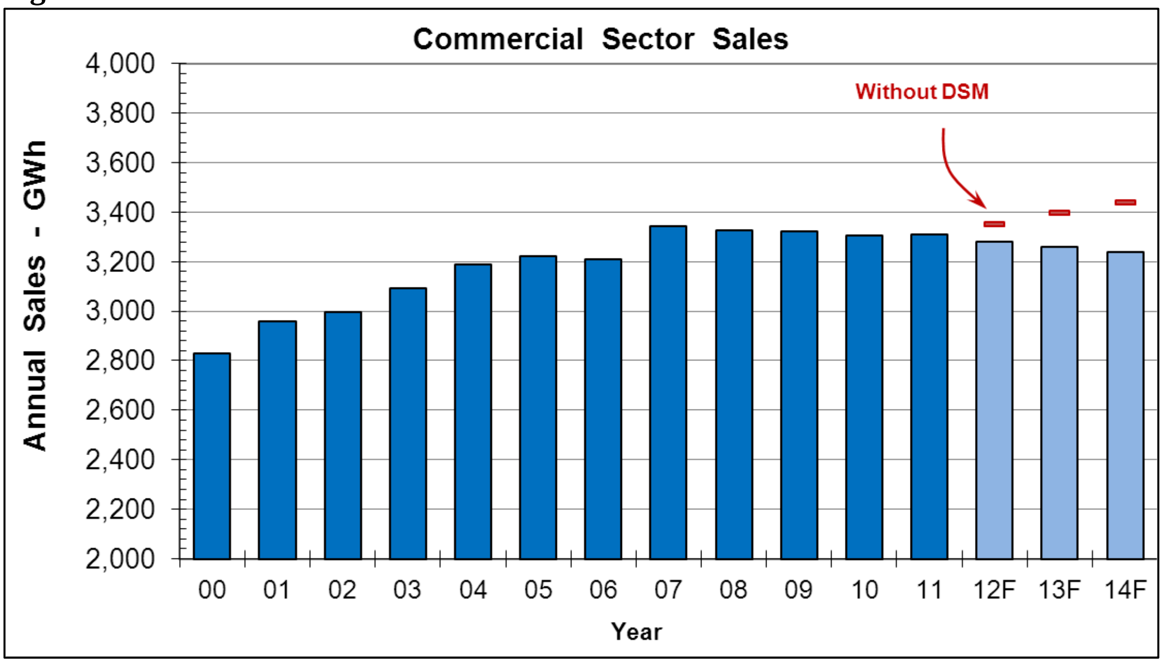
Figure 3-9

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

Commercial Sector Forecast Accuracy			
Year	Forecast (GWh)	Actual (GWh)	Variance (%)
2008	3,345	3,327	-0.5
2009	3,449	3,320	-3.7
2010	3,319	3,305	-0.4
2011	3,376	3,310	-1.9

The chart below show the recent trend in commercial sector energy sales.

Figure 3-10



3.4.3 Industrial Sector

The industrial sector includes customers who manufacture finished goods, or who process material to make products of higher value. The class consists of relatively few customers spanning a variety of industries. They include fish plants, food processors, pulp and paper mills, saw mills, mines, tire manufacturers, furniture makers, and clothing manufacturers. Factors external to Nova Scotia, such as foreign exchange rates and international demand for their products, can exert a heavy influence on their electricity use. Unplanned plant or production changes within this group add to the uncertainty of the industrial load forecast.

In 2013, we forecast industrial sales to make up 22 percent of in-province energy requirements.

To develop the load forecast for this sector, we use a combination of previous trends, large customer surveys, and econometric modeling. Our econometric models for small and medium industrial classes reflect the close link between electricity consumption and GDP.

The forecast for large industrial classes, which have the greatest impact on overall load, takes account of economic conditions, changes in technology and end-uses, planned production changes, shutdowns, and changes in the electric intensity of processes. In our experience, customer surveys capture this information more effectively than general economic measures like GDP. Consequently, the large industrial forecast leans heavily on surveys.

From its high in 2005 to 2011, Nova Scotia's industrial load declined more than 16 percent.

Figure 3-11 shows historical forecast accuracy for this sector.

Figure 3-11

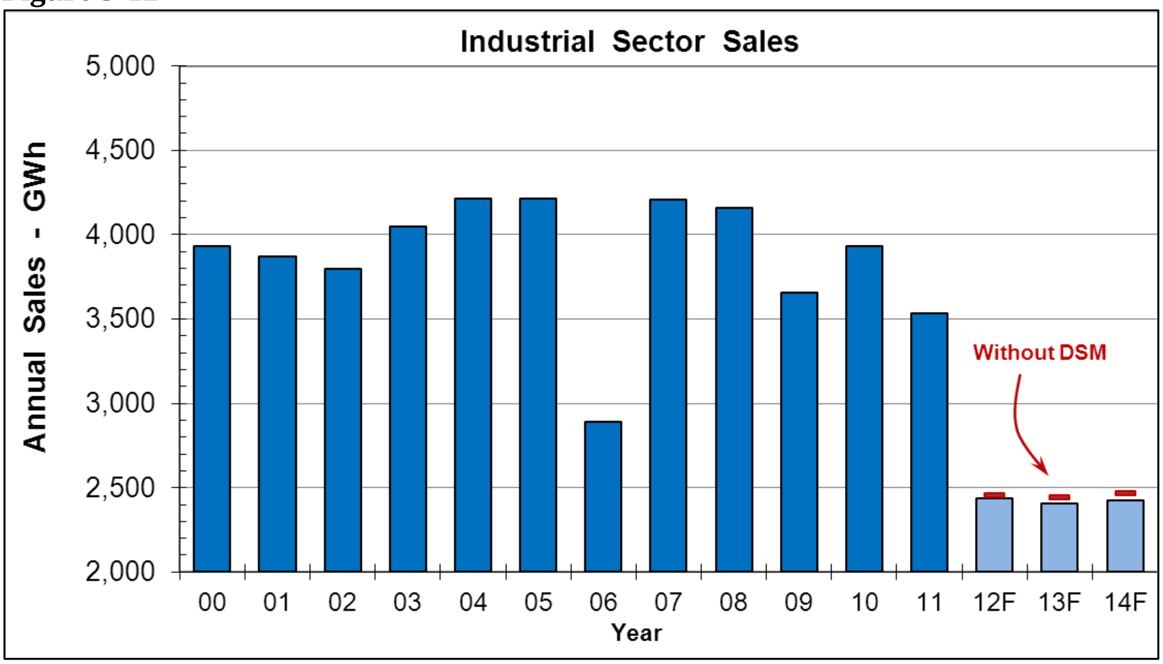
Industrial Sector Forecast Accuracy			
Year	**Forecast (GWh)**	**Actual (GWh)**	**Variance (%)**
2000	3,806	3,930	3.3
2001	4,020	3,873	-3.7
2002	4,008	3,799	-5.2
2003	3,899	4,046	3.8
2004	4,120	4,212	2.2
2005	4,339	4,215	-2.9

Industrial Sector Forecast Accuracy			
Year	**Forecast (GWh)**	**Actual (GWh)**	**Variance (%)**
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
2011*	3,901	3,535	-9.4

*In 2006 and again in 2011, the province's largest paper mill closed for several months.
**In 2009, economic conditions led to temporary shutdowns of some large industrial customers, and reduced production for many others.

The chart below shows the recent trend in industrial sector energy sales.

Figure 3-12



3.4.4 Exports

When economically and technically feasible, NS Power sells energy to customers outside Nova Scotia. Sales usually occur during periods of low in-province demand. The margin on these sales have an impact on the Fuel Adjustment Mechanism, thereby reducing the revenue required from in-province customers. The forecast method for exports is described in the Fuel Section.

Figure 3-13 shows export sales over the years 2000 to 2011 and forecasts for 2012 to 2014. We forecast export sales of 28.9 GWh in 2013 and 29.5 GWh for 2014. Associated losses of 3 percent bring the total export requirement to 29.8 GWh and 30.4 GWh, which are the figures we use in this Application.

Figure 3-13

Export Sales		
Year	**Sales (GWh)**	**Change yr/yr (GWh)**
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
2011	9	-3
2012F	132	123
2013F	29	-103
2014F	30	1

3.4.5 Line Losses

The percentage of energy lost in delivery varies with volume, delivery voltage, ambient temperature, and line impedance. Overall, we forecast delivery losses in the range of 6.5 percent of the net in-province energy requirement.

3.4.6 Demand Side Management

Demand Side Management (DSM) programs administered by Efficiency Nova Scotia Corporation (ENSC) continue to play an important role in forecasting electric load. The load forecast uses the annual energy and demand savings targets estimated in the 2011 and 2012 DSM filings.[14] For 2013 and 2014, we applied the DSM targets ENSC proposed to stakeholders in December 2011, which was the most up to date information available. The savings from DSM programs in previous years are embedded in the actual sales for those years.

When applying DSM adjustments to the annual load forecast, NS Power recognizes that the actual energy saving in the first year will fall short of the target, since the device or measure will not be in place for the full twelve months of the year. We assume that DSM measures will be implemented, on average, at mid-year. This results in a realized load change of 50 percent of the target in the year of implementation, and the remaining 50 percent in the following year. As a result, the load forecast inputs for DSM do not precisely match the DSM targets from which they were built.[15]

The table below depicts annual DSM energy saving targets, and the load adjustments that result from these measures.

Figure 3-14

Year	ENSC DSM Plan (GWh)	50% of Current Year Plan (GWh)	50% of Prior Year Plan (GWh)	Realized Annual Increment (GWh)	Realized Cumulative Reduction to Forecast (GWh)
2011	158.5	79	N/A	N/A	N/A

[14] NSPI 2011 Demand Side Management Plan, NSUARB-NSPI-P-884(3), February 26, 2010.
ENSC 2012 Demand Side Management Plan, NSUARB-E-ENSC-R-10, February 28, 2011.
[15] When DSM targets are similar from year to year, this essentially results in the same figures, as shown in the table for 2013. This methodology was developed to more accurately reflect the DSM forecast effects during the program ramp up.

Year	ENSC DSM Plan (GWh)	50% of Current Year Plan (GWh)	50% of Prior Year Plan (GWh)	Realized Annual Increment (GWh)	Realized Cumulative Reduction to Forecast (GWh)
2012	134.1	67	79	146	146
2013	133.3	67	67	134	280
2014	133.3	67	67	133	413

3.5 2011 Peak Demand Forecast

3.5.1 System Peak

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

The hourly peak demand during the last two winters was:

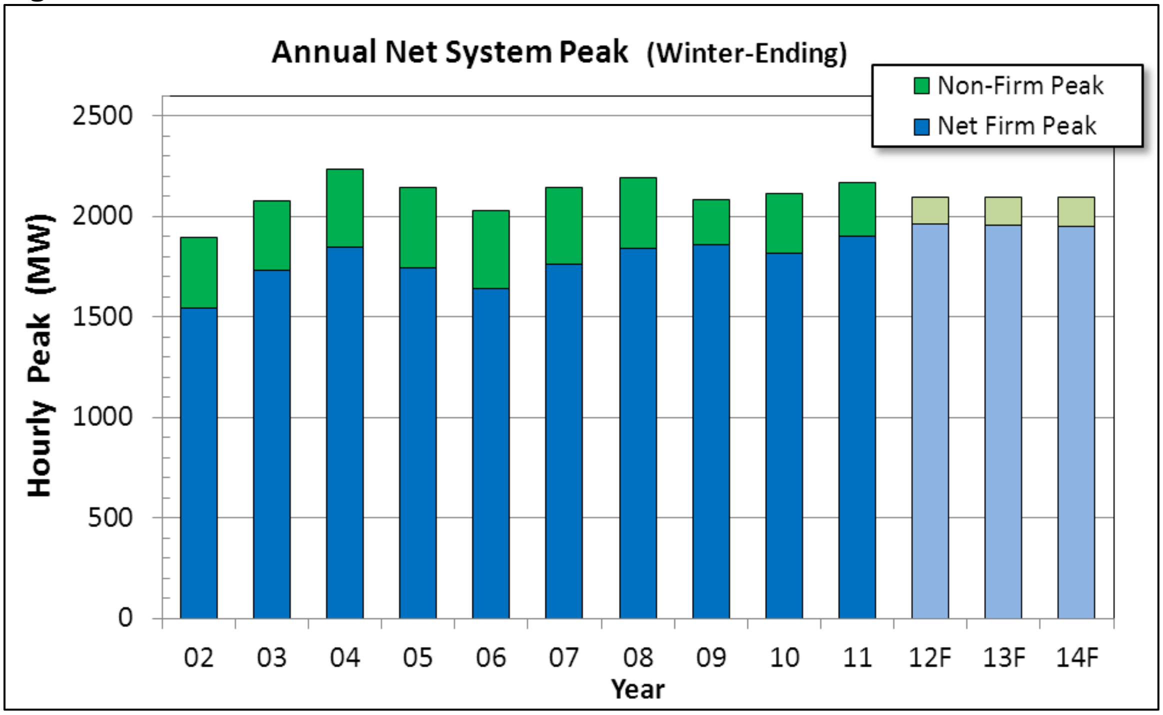
- 2009/2010 2,114 MW
- 2010/2011 2,168 MW

The forecast peak for 2013 and 2014 is:

- 2013 2,098 MW
- 2014 2,093 MW

We base this forecast on a variety of data, including industrial customer load and typical winter temperatures, and we use these values for rate-making purposes. Please refer to Figure 3-15. The reduction in peak demand results from the expected removal of more than 175 MW of industrial load due to changes at the major paper mills.

Figure 3-15



3.5.2 Non-Firm Coincident Peak

Industrial customers who meet specific criteria allow NS Power to interrupt their electricity supply on short notice in order to reduce peak demand in emergencies when shedding load is critical to system stability. In return for this contractual flexibility, they pay a lower, *non-firm* rate.

One 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. In recent years, they typically ranged between 300 MW and 350 MW. However, with the changes at the large paper mills, they have been reduced to less than 150 MW in this forecast.

3.5.3 Total Coincident Firm Peak

Total Coincident Firm Peak is the portion of electricity demand at the time of a system peak caused by non-interruptible, or 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 greatly with weather.

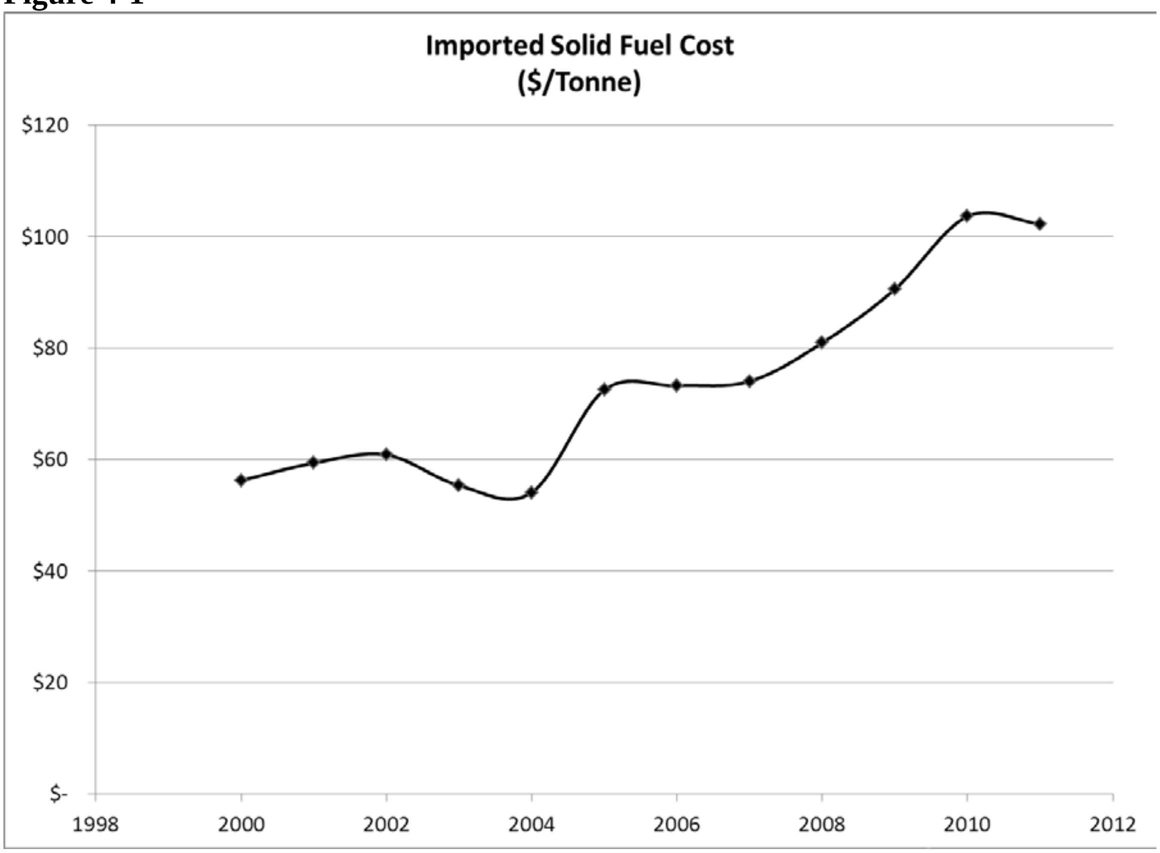
In January 2011, the firm peak was 1,903 MW and we forecast a firm peak of 2,098 MW for 2013, based on typical winter temperatures.

4 FUEL AND PURCHASED POWER

4.1 Overview

Of all the factors that determine the cost of electricity in Nova Scotia, the largest variable is fuel. It is a variable in the sense that fuel prices keep changing. World prices change often, and they change unpredictably. Over the last decade, the cost of coal, like the cost of other fossil fuels, has bounced up and down along an upward trajectory. Over the last decade, prices for imported solid fuel have nearly doubled. Some of this increase is driven by the need to meet increasingly stringent emissions limits.

Figure 4-1



When Nova Scotia committed to coal-fired generation decades ago, the coal we used was mined here in the Province. That meant jobs and economic growth for Nova Scotians.

When the mines closed at the turn of the century, our fuel supply moved offshore. The need for coals containing lower sulfur and lower mercury content has resulted in our becoming increasingly dependent on world markets, and therefore more vulnerable to volatile world prices. Domestic coal now accounts for 18 percent of our solid fuel consumption.

In more recent years, air emissions standards have become increasingly strict. To meet them, NS Power has had to buy low-sulphur and low-mercury coals, which are more expensive than the coal we used to burn.

NS Power uses numerous strategies to reduce fuel expense. These include:

- Conducting multiple test burns each year on new potentially lower cost solid fuel sources

- Switching between coal and natural gas as the market price for these fuels change relative to one another

- Utilizing solid fuel procurement practices that attract a broad diversity of supply from a wide variety of coal suppliers in North and South America

- Using a variety of fuel “blends” at the solid fuel-based generating stations

NS Power also employs a variety of techniques to protect customers from the volatility in world fuel markets. These include:

- Employing contracts of varying lengths with staggered expiration
- Entering into financial hedges that fix or serve to average fuel prices over time

Changes in the price of fuel and purchased power pose a problem when it comes to setting rates. If we overestimate the future price of fuel, and rates are set accordingly, customers will pay too much for electricity. If we underestimate the future price, NS Power will face a revenue shortfall.

The Board recognized this problem in the 2009 GRA decision, when it approved a Fuel Adjustment Mechanism (FAM).[16] The FAM adjusts the price of electricity at the start of each year to reflect changes in the actual cost of fuel and purchased power. The FAM helps the Board strike a fair balance between the Company and its customers. Without the transparency of the Fuel Adjustment Mechanism, the rate setting process would be more difficult.

As world coal prices climbed in recent years, this has meant annual increases based solely on the cost of fuel, before any other costs of producing electricity were factored in.

The Fuel Adjustment Mechanism includes a Plan of Administration, which provides the rules for calculating fuel and purchased power costs that determine each year's rate adjustment, if any. The process is complicated, but it ensures customers pay only actual fuel costs; no more, no less. The Plan of Administration starts by establishing the Base Cost of Fuel, which is a projection of fuel and purchased power costs expected in the coming year. These projected costs are trued up once actual costs are known, resulting in annual rate adjustments that are implemented each January 1st. The Plan of Administration was developed in collaboration with customers and the Board.

NS Power is seeking a reset of the Base Cost of Fuel as part of this General Rate Application. Because we are requesting rate increases in each of the next two years, this Application includes projected fuel and purchased power costs for both 2013 and 2014. This includes details about our fuel procurement strategy, fuel portfolio, and our 2013 and 2014 fuel forecasts.

[16] NSPI 2009 General Rate Application, UARB Order, NSUARB-NSPI-P-888, December 8, 2008.

In addition to coal, petcoke, fuel oil, natural gas, and purchased power, this year's projections include the cost of biomass fuel to be used at the Port Hawkesbury biomass facility, scheduled to come on-line in 2013. Aside from test burns at the Point Aconi generating station, NS Power has not previously used biomass fuel. The Plan of Administration is silent on how to calculate these costs. We based our biomass pricing forecast for 2013 on an update to the assumptions used in the Application for approval to build the Port Hawkesbury biomass plant.[17] NS Power will work with stakeholders in the FAM Small Working Group to bring forward appropriate amendments to the Fuel Manual relating to the procurement of fuel for the biomass plant.

Variances from the Fuel Forecasting methodology outlined in the Appendix B of the FAM Plan of Administration were made for 2013 for Mid-Sulfur Coal and HFO. A downward adjustment in mid-sulfur forecast pricing was made based on discussions with the company that provides mid-sulphur coal price forecasts. Please refer to the Standardized Filing SR-03 for additional details.

The FAM Plan of Administration does not anticipate a multi-year filing. As a result, we used additional assumptions, beyond those outlined in the Plan of Administration, to create the 2014 forecast. Please refer to the Standardized filing SR-03 for additional details.

For additional information, please refer to the following standardized filing documents:

Figure 4-2

Code	Description	Code	Description
SR-03	Fuel Price Forecasts	OE-01F	Fuel Procurement Manual
OP-05	Power Production Maintenance Schedule	OE-01G	Fossil Fuel Projection to Replace Natural Gas
OP-06	Generating Units by Type	OE-01H	Solid Fuel Costs
OP-07	Fuel Specification Sheets	OE-01I	Solid Fuel Transportation Details
OP-08	IPP Contracts	OE-01J	Fuel Hedging Programs
OP-09	Reliability Statistics	OE-01K	Forecast Solid Fuel Prices
OR-08	Sales of Natural Gas	OE-01L	Natural Gas Details

[17] NSPI Port Hawkesbury Biomass Project, Capital Work Order Application, CI 39029, NSUARB-NSPI-P-128.10, April 9, 2010.

OE-01A	Fuel Forecast	OE-01M	Fuel-Related Affiliate Transactions
OE-01B	Forecast of Fuel Burn Levels	OE-01N	Latest Fuel Supply / Transportation Studies
OE-01C	Fuel Costs per MWh	OE-01O	Export / Import Power Calculations
OE-01D	History of Fossil Fuel Usage	OE-01P	Force Majeure Issues
OE-01E	Summary of Fuel Contracts	OE-01Q	Fuel for Resale - Cost / Recoveries

4.2 Generation by Fuel Type

Nova Scotia Power has 2,474 MW of generating capacity. Coal-fired plants account for 50 percent of this capacity, while natural gas and oil-fired plants make up 28 percent. Hydro, tidal, biomass, and wind provide the rest, about 22 percent. The natural gas and renewable share of our generating capacity has grown rapidly in recent years, and will soon account for more than half of NS Power's total generating capacity.

NS Power's energy schedulers continuously determine which plants to operate, and their level of generation, a process known as *dispatching the fleet*. They base these choices mainly on each plant's marginal cost of generation at the time they are making the decision. These decisions must also ensure that environmental and reliability requirements are met.

In 2013, NS Power will pass a milestone when, for the first time, we forecast less than half our electricity will come from coal-fired plants. Coal and petcoke (collectively referred to as solid fuel) is forecast to account for only 48 percent of our generation, down from 80 percent in 2006. Natural gas is expected to account for 25 percent.

For 2014, we forecast an increase in the price of natural gas. Since we must still base our fleet dispatching decisions on the cheapest form of generation, this change will cause a slight uptick in the forecast percentage of solid fuel generation to 52 percent in that year. We forecast natural gas to decrease to 19 percent of our total 2014 generation.

In both 2013 and 2014, we expect four percent of NS Power's energy to come from import purchases, with the remaining 23 percent in 2013, and 25 percent in 2014, to come from a combination of NS Power-owned hydro, wind, biomass, tidal, and renewable purchased power.

Figure 4-3 and Figure 4-4 provide a breakdown of generation by type for 2013 and 2014, respectively.

Figure 4-3

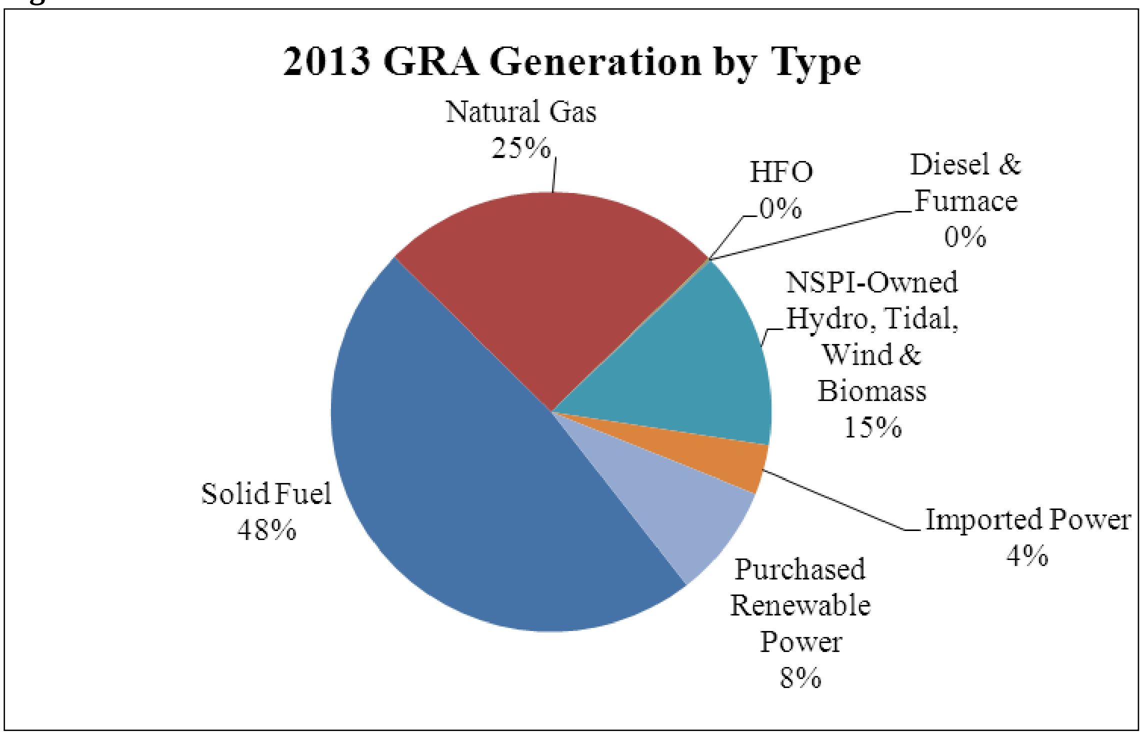
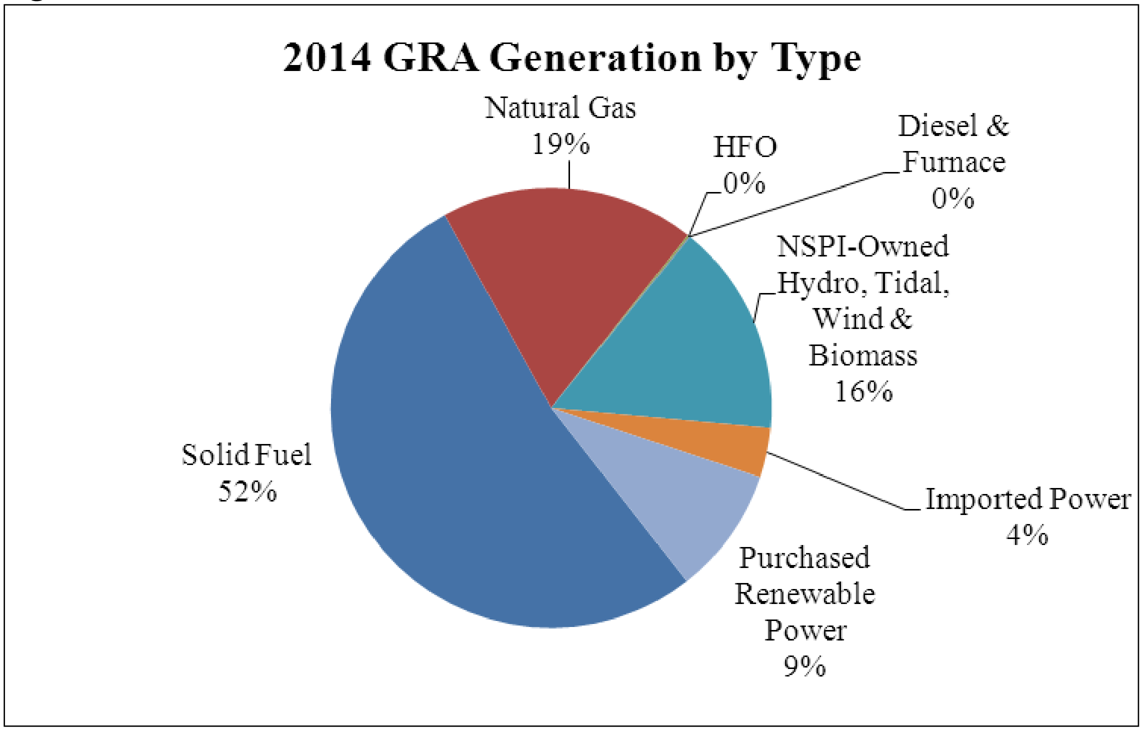


Figure 4-4



4.2.1 Renewable Energy

NS Power operates a wide variety of renewable energy generators. For 2013, our renewable energy will come from wind, hydro, tidal, and biomass. We will also purchase renewable energy from independent power producers and community groups across the province. For 2014, we project that 25 percent of our electricity will come from renewable energy sources - up from less than 10 percent in 2007. This turnaround reflects government legislation that allows NS Power, along with large-scale private producers and community groups to progress toward our ambitious shared goal of 40 percent renewable energy by 2020. NS Power's compliance plan for these targets can be found in Appendix C.

The Port Hawkesbury biomass generating plant is an important part of NS Power's efforts to meet Nova Scotia's Renewable Electricity Standards. We expect this facility to begin operations in the second quarter of 2013. It will provide 3 percent of the NS

Power's energy generation in 2013 when it will run for a portion of the year, and four percent in 2014.

4.2.2 Natural Gas

While we are rapidly increasing our renewable generation, we also want to retain flexibility in the fuels at our disposal. Retaining a variety of fuel sources gives us the flexibility to respond to price swings in natural gas and solid fuels. That lets us supply electricity at the lowest possible cost.

In 2000, NS Power converted its Tufts Cove generating station so that it could burn natural gas, in addition to oil. At the same time, we signed a long-term supply agreement for gas from the Sable Offshore Energy Project. This let us reduce total fuel costs to our customers by selecting the most economical choice between selling the gas into the New England marketplace or burning it at Tufts Cove.

NS Power's current contracts to purchase natural gas are now priced based on specific market locations in the north-eastern United States.

Natural gas releases only about half as much carbon dioxide per unit of energy as coal, and it releases no mercury and virtually no sulphur. A rapid increase in North American gas supplies has made it an attractive alternative to coal and petcoke, and a key element in our strategy for achieving cleaner, local, affordable electricity.

4.2.3 Oil

NS Power no longer uses heavy fuel oil (HFO) as a primary fuel to generate electricity due to its high cost relative to natural gas or solid fuels. HFO is used as a start-up fuel in the coal-fired plants, and therefore accounts for less than one percent of our generation.

4.2.4 Solid Fuel

In buying coal and petcoke, NS Power's goal is to have a reliable, competitively priced fuel supply, bearing in mind the operating costs for each plant in our generation fleet, and the need to strictly observe all regulatory and environmental requirements. This requires a portfolio approach, with contracts spanning various time frames, suppliers, and fuel characteristics. NS Power's solid fuel costs include the cost of transportation. Please refer to Appendix B for detailed information on our solid fuel portfolio and information on solid fuel transportation costs.

4.3 2013 and 2014 Fuel Costs and Mix

The transformation now underway in our generation mix has required a number of changes to our portfolio strategy. Uncertainty around the status of our largest industrial customers, together with our increased use of natural gas, has made it harder to predict how much solid fuel and natural gas we will consume. Uncertainty about the amount of coal we will use also causes uncertainty around the optimal mix of solid fuels. Lower gas prices allow us to use less expensive, coal and petcoke while still meeting emissions limits. For these reasons, we continually monitor our purchase commitments and expected requirements to give us greater flexibility in deciding when and what to buy.

NS Power has been able to make large shifts in the amount of solid fuel and natural gas we use from year to year, so as to take advantage of price changes in these commodities relative to one another.

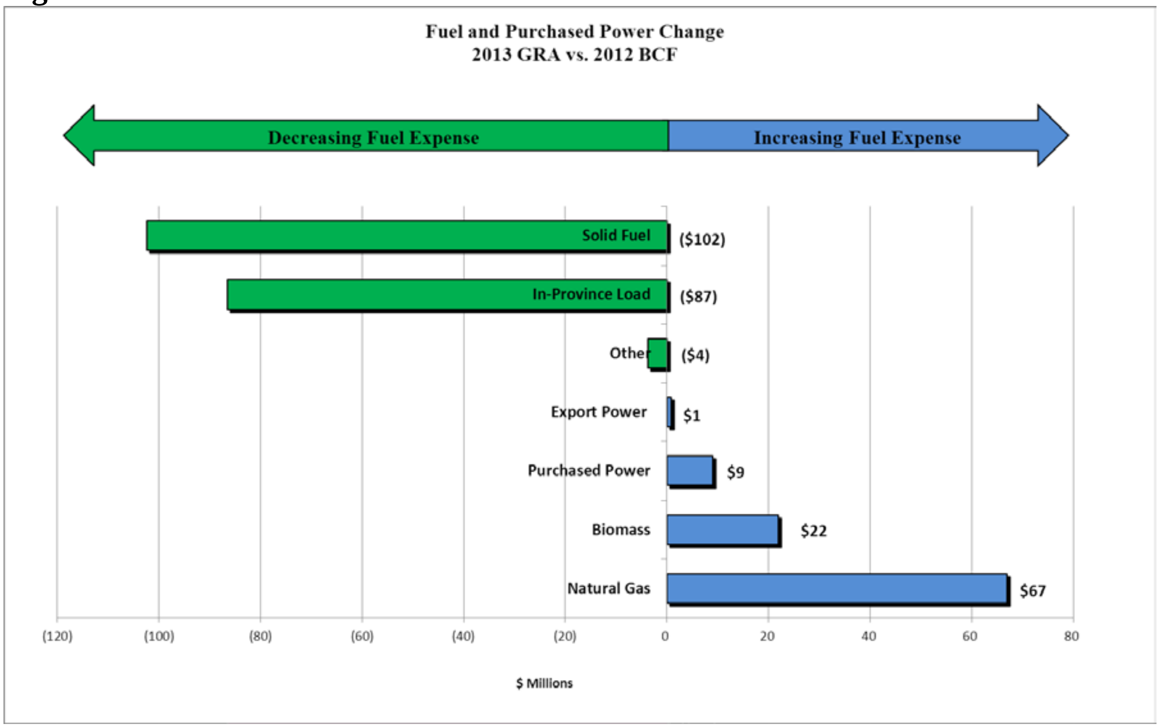
4.4 Fuel Forecast – Change in 2013 Compared to 2012

Fuel costs include the delivered cost of solid fuels, natural gas, oil, and purchased power, offset by the net proceeds from export energy sales. Fuel forecasts are developed based on the methodology outlined in the FAM POA.

NS Power's current rates include $569.1 million for purchases of fuel and imported power. Since the 2012 Base Cost of Fuel (BCF) was set, changes in the relative price of solid fuel versus natural gas have led us to decrease our forecast use of solid fuel in 2013, and increase our forecast use of natural gas. As well, we forecast a decrease in the cost per megawatt-hour of both solid fuel and natural gas in 2013 (as shown in Figure 4-7).

For 2013 we project fuel and purchased power costs of $475 million, $94.1 million lower than the amount included in the 2012 BCF. Figure 4-5 shows the major components of this change.

Figure 4-5

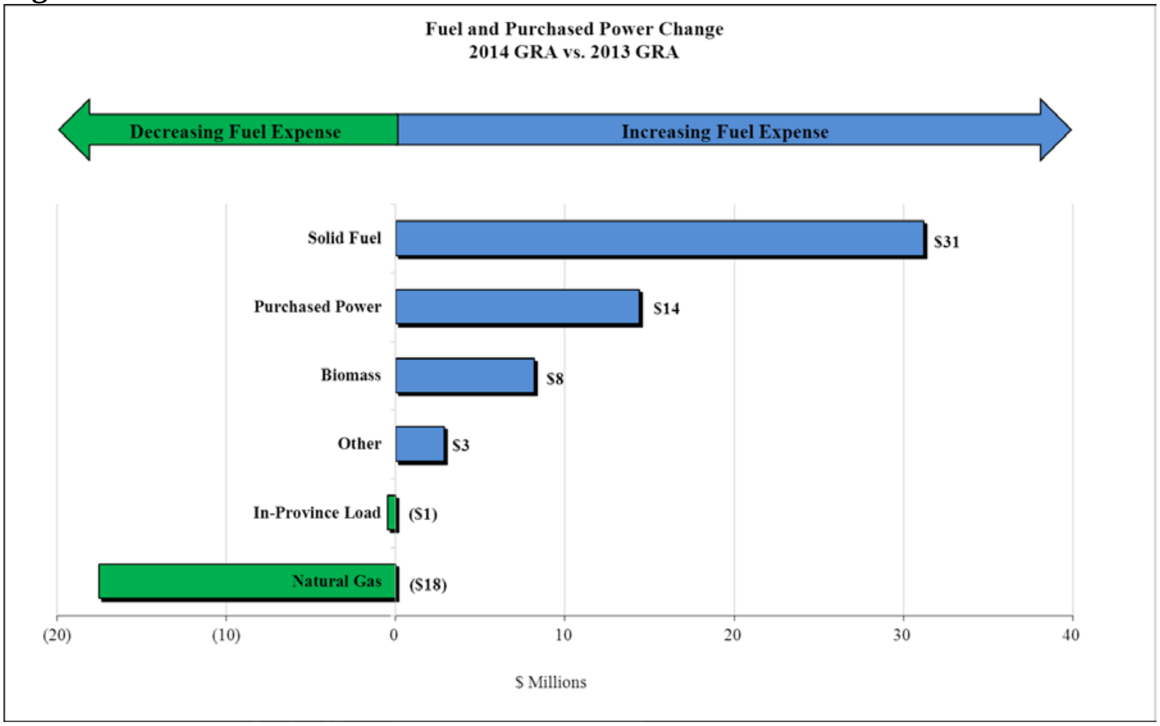


4.5 Fuel Forecast – Change in 2014 Compared to 2013 Forecast

In 2014, we project a fuel cost of $513.7 million, $38.7 million higher than the 2013 forecast. Forecast load will remain stable in 2014 relative to 2013. The projected increase in fuel costs results from a higher forecast price for both solid fuel and natural gas (see Figure 4-8). Natural gas prices in 2014 are expected to increase more than solid fuel prices. The extent of that change in relative pricing will cause the total fuel expense for natural gas to decrease as we use more of the less expensive solid fuel and less natural gas.

NS Power will also produce more energy from biomass in 2014, relative to 2013. Figure 4-6 illustrates these changes.

Figure 4-6



NS Power’s fuel forecasts are based on the best available information available at the time that the forecast is created. Actual fuel expense will vary from the forecast based on changes in load of major industrial customers or changes in the relative costs of coal and natural gas. However, customers will only pay the actual costs of fuel expense incurred.

4.5.1 Solid Fuel

The change in solid fuel represents the single largest reason for the decline in the Base Cost of Fuel in 2013. Natural gas is forecast to have a larger price drop per MWh than that of solid fuel. Therefore, with the forecast drop in load, solid fuel will preferentially be removed from the fuel mix. Lower coal prices reflect an expected softening in market prices. Lowered consumption will enable NS Power to use a higher proportion of low cost, mid-sulphur coal and petcoke in both 2013 and 2014, while meeting emissions standards for our thermal plants. In 2014, we forecast a $31.2 million increase in solid fuel costs. The increase reflects a partial reversal of some of the trends in 2013, including an increase in volume and a resulting increase in the use of higher quality coals to meet environmental standards.

4.5.2 Load

The reduced load accounts for $86.5 million of the reduction in our forecast fuel and purchased power expense for 2013. In 2014, as detailed in the Load Section, we expect in-province load to decline slightly.

4.5.3 Purchased Power

Purchased power consists of:

- imported power from outside of Nova Scotia
- purchases from Independent Power Producers within Nova Scotia (Wind, hydro, biomass, and biogas)

Purchased power costs are expected to rise as a result of the requirement to purchase increased amounts of renewable energy. This energy is primarily from Independent Power Producers (IPPs) operating within Nova Scotia. Provincial regulations require NS Power to meet part of its renewable energy requirements with purchases from IPPs, and from community groups. We forecast purchased power to increase by 12 GWh in 2013, and then by an additional 105.1 GWh in 2014. The increase in 2014 is driven by the addition of new renewables.

4.5.4 Natural Gas

In 2013, the forecast decrease in natural gas prices will lead to an increase in our forecast total natural gas expense as the reduced price entices us to increase the proportion of natural gas while decreasing the amount of solid fuel in our fuel mix. In 2014, we expect the opposite to occur: an increase in natural gas prices that will moderately reduce the amount of electricity we generate from that fuel. As a result, our overall natural gas budget will decrease.

4.5.5 Export Power

The forecasting method prescribed in the FAM requires us to assume that NS Power will use 50 percent of unused capacity at Tufts Cove Units 2 and 3 for export.[18] In 2013, we forecast a reduction in the amount of excess capacity at Tufts Cove, as lower natural gas prices cause us to make greater use of this facility. Although we expect to burn less natural gas in 2014, due to higher heat rate of Tufts Cove Unit 1, it will be taking the largest proportionate share of reduced generation. As a result, we expect export volumes and costs to increase only marginally in that year.

4.5.6 Other

This category includes a decrease of $3.8 million, mostly due to decreases in heavy fuel oil, light fuel oil, and diesel related to the decreased need for auxiliary fuels at the coal plants in 2013. In 2014 there is a $2.8 million increase over the 2013 forecast, mostly related to increased use of mercury additives.

Figure 4-7 shows the changes in fuel costs per dollar per megawatt hour (MWh) of electricity produced in 2013 vs. 2012. Reductions in natural gas and solid fuel costs more than offset the increases in the other categories.

[18] NSPI Fuel Adjustment Mechanism, Plan of Administration, Appendix B, Page 15.

Figure 4-7

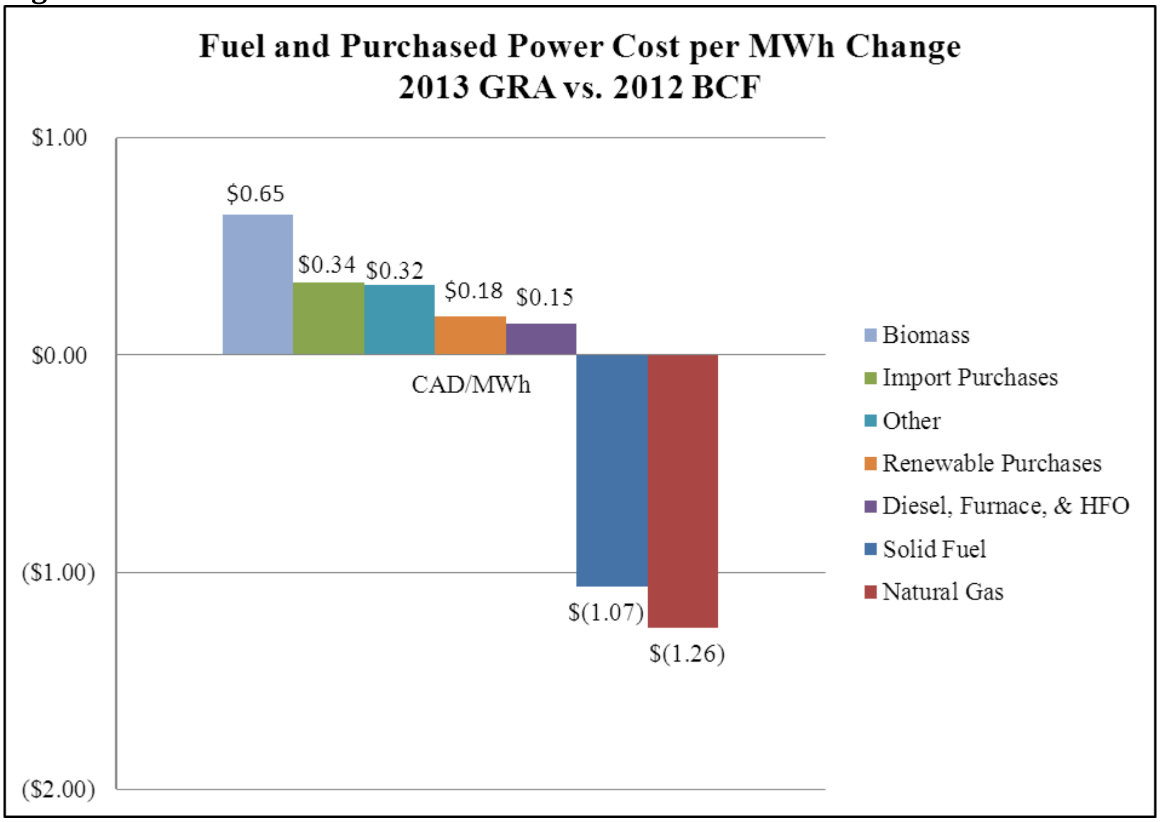
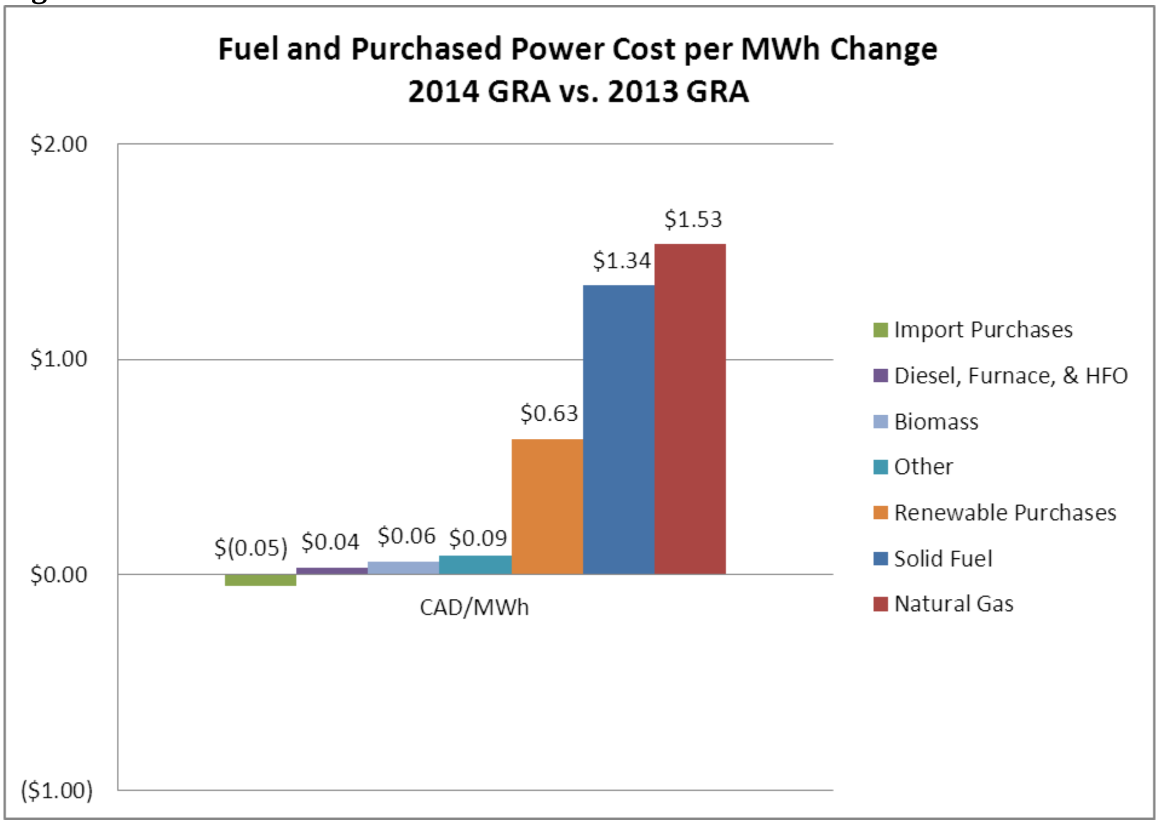


Figure 4-8 shows the changes in fuel costs per dollar per megawatt hour (MWh) of electricity produced in 2014 vs. 2013. In contrast to the previous year, we expect cost increases in almost all categories.

Figure 4-8

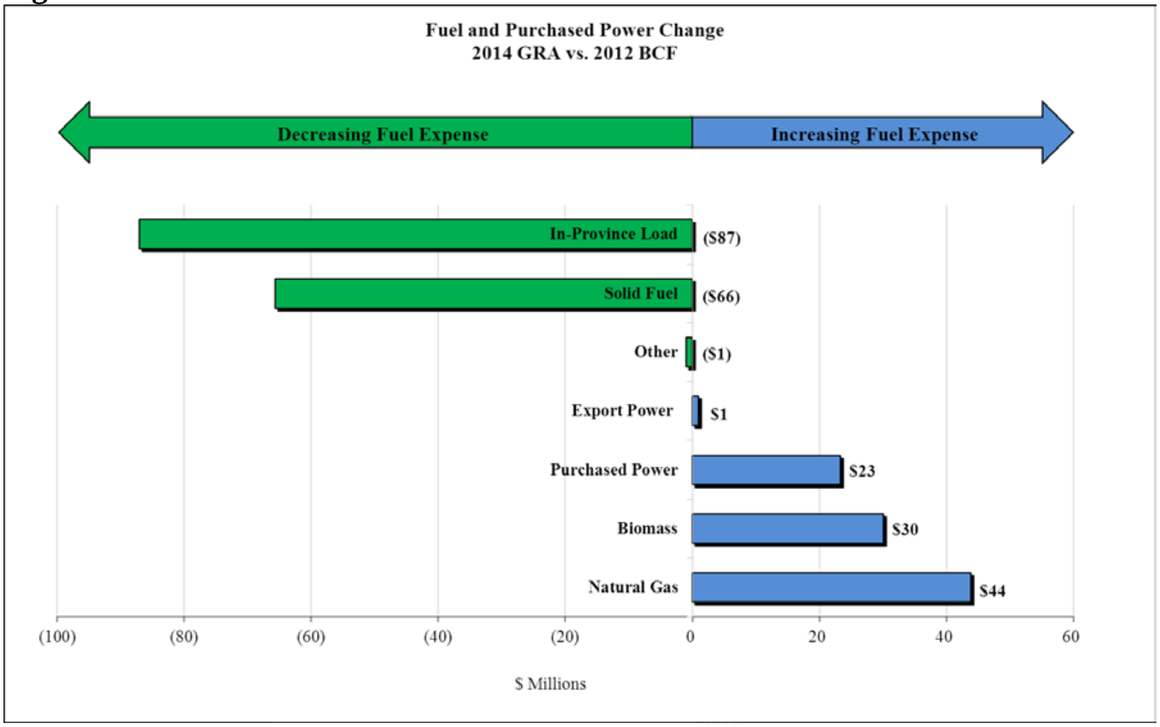


4.6 Summary

The 2012 Base Cost of Fuel included fuel and purchased power expenses of $569.1 million. We forecast fuel costs to fall by $94.1 million to $475 million in 2013, and then to rise by $38.7 million to $513.7 million in 2014.

The net changes between 2014 and 2012 are shown in Figure 4-9.

Figure 4-9



Note: In some cases, the change in fuel costs, based on net change in fuel expense, from 2012 to 2014 differs from the sum of the individual changes across the 2 years. This is due to the impacts of rounding and the method used in applying the change in load to solid fuel and natural gas consumption.

The forecast decline in load, mostly driven by large industrials, is the largest single factor affecting the decrease in total fuel costs between 2012 and 2014. The application of the FAM forecasting methodology results in an increase in the relative costs of generation from natural gas versus coal. Fuel expense is increasing due to the requirement to generate electricity from renewable sources including: COMFIT, IPPs, and biomass-based.

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 NS Power with expert advice on solid fuel procurement. We also retain Leonard Crook of ICF International for advice on natural gas procurement. Mr. Crook’s evidence is included in Appendix D.

Both Mr. Crook and Ms. Medine are available to assist the Board in its deliberations by filing expert evidence in reply to matters that may be in issue at the time of the hearing.

5 FUEL ADJUSTMENT MECHANISM

In 2008, the Board approved a Fuel Adjustment Mechanism (FAM).[19] The FAM adjusts the price of electricity at the start of each year to reflect the actual cost of fuel used to produce electricity in the prior year. It allows rates to reflect the latest information about fuel costs, so that customers pay the actual fuel costs – no more, no less.

This Application sets forth our proposals for resetting the 2013 and 2014 Base Cost of Fuel. Because this Application combines two years, we propose to establish a Base Cost of Fuel for 2013 and a Base Cost of Fuel for 2014, reflecting our projected fuel costs for each year.

> The FAM includes an incentive that gives 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, to a maximum of $5 million.[20]

As part of the 2012 approved GRA settlement, the FAM incentive was suspended for 2012.[21] Due to continuing uncertainty about the load for the pulp and paper industry, we propose that the FAM incentive remain suspended through 2013 and 2014. The suspension of the FAM incentive mechanism is also a component of the Rate Stabilization Plan.

Under the FAM framework, base fuel costs are reset every two years and as part of a GRA.[22] In this Application, we will be setting a base cost of fuel for 2013 and again for

[19] NSPI 2009 General Rate Application, UARB Order, NSUARB-NSPI-P-888, December 8, 2009.
[20] NSPI Fuel Adjustment Mechanism, Plan of Administration, NSUARB-NSPI-P-887, October 15, 2008, page 1, paragraph 6.
[21] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011, page 1, paragraph 3.
[22] NSPI Fuel Adjustment Mechanism, Plan of Administration, NSUARB-NSPI-P-887, October 15, 2008, page 1, paragraph 3.

2014. The Board last approved a reset of the BCF in the 2012 GRA.[23] Under the FAM, if actual fuel costs prove to be lower than those forecast, customers will pay no more than our actual, prudently incurred fuel costs. This is done through a separate adjustment process each year. Under or over-recoveries in 2013 and 2014 would be recovered or refunded to customers in subsequent years. Under the Rate Stabilization Plan, FAM AA adjustments relating to 2013 or 2014 would be deferred within the FAM so that customer rates can remain stable for the next two years.

This Application enables the Board to consider all evidence relevant to both the Base Cost of Fuel and the 2013 and 2014 revenue requirements. The Board can establish the Base Cost of Fuel amount for the FAM for 2013, and for 2014, using the fuel forecast evidence in this proceeding. The amount to be included in rates for fuel and purchased power expenses effective January 1, 2013, and January 1, 2014, provides for recovery of fuel costs in each year.

The FAM requires Nova Scotia Power to prepare a fuel forecast each year over the summer, and to file it according to the FAM schedule.[24] NS Power will file an updated fuel Standardized Filing for the FAM process no later than August 31. This will provide helpful evidence for the Board's consideration of this General Rate Application.

Preparation and implementation of the FAM, which includes a regular cycle of detailed reporting, will continue in parallel with this proceeding. The FAM process includes an annual actual adjustment and a balance adjustment, both of which will be reviewed on the usual FAM schedule in November of this year, to be effective on January 1, 2013. Therefore, this Application does not include calculations for these adjustments.

[23] NSPI 2012 General Rate Application, Decision, NSUARB-NSPI-P-892, November 29, 2011. Appendix A, Page 1, Note 3.
[24] NSPI Fuel Adjustment Mechanism, Plan of Administration, NSUARB-NSPI-P-887, October 15, 2008, Appendix D, page 7-11.

6 OPERATING COSTS

6.1 Overview

Known in previous applications as OM&G – Operations, Maintenance, and General – this section covers the expenses required to run a large, technically complex electricity system. Operating costs attract close scrutiny from interveners concerned about rate increases, and understandably eager to find and eliminate any unnecessary costs used to calculate Nova Scotia's electricity rates.

One of the strengths of the regulatory process is the opportunity it provides customers and their representatives to cast critical eyes on the assumptions, policies, and practices that go into our operations. This process strengthens NS Power as a company, helps ensure a robust and efficient electricity system, and results in the best value for customers.

We are confident that NS Power is a cost-effective, well-run company. Independent audits have repeatedly confirmed this assessment. Our employees devote great effort to finding more effective, less expensive ways to achieve our shared goal of delivering safe, reliable electricity. This is especially true during the current period of transformation as we adapt to the loss of pulp and paper load and change from a system based on imported high-carbon intensity fuels to one based more on clean, local, renewable energy sources. In response to evolving environmental regulations that focus on solid fuel, we have made changes in the way we operate our legacy thermal plants, and reduced staffing levels – all with a view to reducing costs and further improving our cost effectiveness.

Some of the operating costs outlined in this Application reflect necessary activities in support of the transformation unfolding in our generation system. Others reflect our need to recruit and retain employees with the training, experience, skill, and work ethic required to carry out many diverse and difficult tasks.

The operating cost increases we seek in this Application focus on improving reliability and customer service and increasing our use of renewable energy.

NS Power's operating costs fall broadly into three areas:

- operating and maintaining our generation, transmission and distribution facilities
- delivering service to customers
- providing corporate support to those functions

We forecast our total operating costs in 2013 at $279.0 million, and in 2014 at $283.1 million. This represents approximately 20 percent of NS Power's total revenue requirement in 2013 and 2014.

The forecast increase for 2013 is $33.4 million more than our 2012 operating costs, projected in the restated 2012 GRA Compliance Filing.[25] The increase includes additional investment in vegetation management and storm response, and new operating expenses associated with the Port Hawkesbury Biomass Plant, scheduled to go into service in April 2013. These three items account for $14.3 million, or 43 percent, of the $33.4 million operating cost increase.

Increases in pension expenses account for $17.8 million, or 53 percent of the $33.4 million. As discussed in Section 1.3, pension expense is increasing due to factors external to NS Power.

The remaining operating cost have been held relatively flat through cost reduction efforts to offset cost escalations for a small net increase of $1.3 million.

[25] NSPI 2012 General Rate Application, Compliance Filing, NSUARB-NSPI-P-892, December 9, 2011.

The forecast increase for 2014 is $4.1 million, or 1.5 percent more than forecast for 2013. This mainly reflects general inflation in annual labour and non-labour costs, partially offset by decreased pension costs.

Comprehensive reviews of NS Power's operating costs consistently show us to be a well-managed utility. As depicted in Appendix A, NS Power has demonstrated a favourable trend in operating costs compared to total revenue over the period. NS Power's revenues have increased at a higher rate than increases in actual operating costs based on the recovery of increased fuel costs. Among competing companies, we are slightly below the 50th percentile for non-union salaries, an appropriate target that the Board has approved for NS Power in many prior rate applications and reviews. Our collective agreement with the International Brotherhood of Electrical Workers (IBEW) expired on March 31, 2012, and we are actively negotiating a new contract at the time of this Application.

Figure 6-1 summarizes the components of the increase.

Figure 6-1

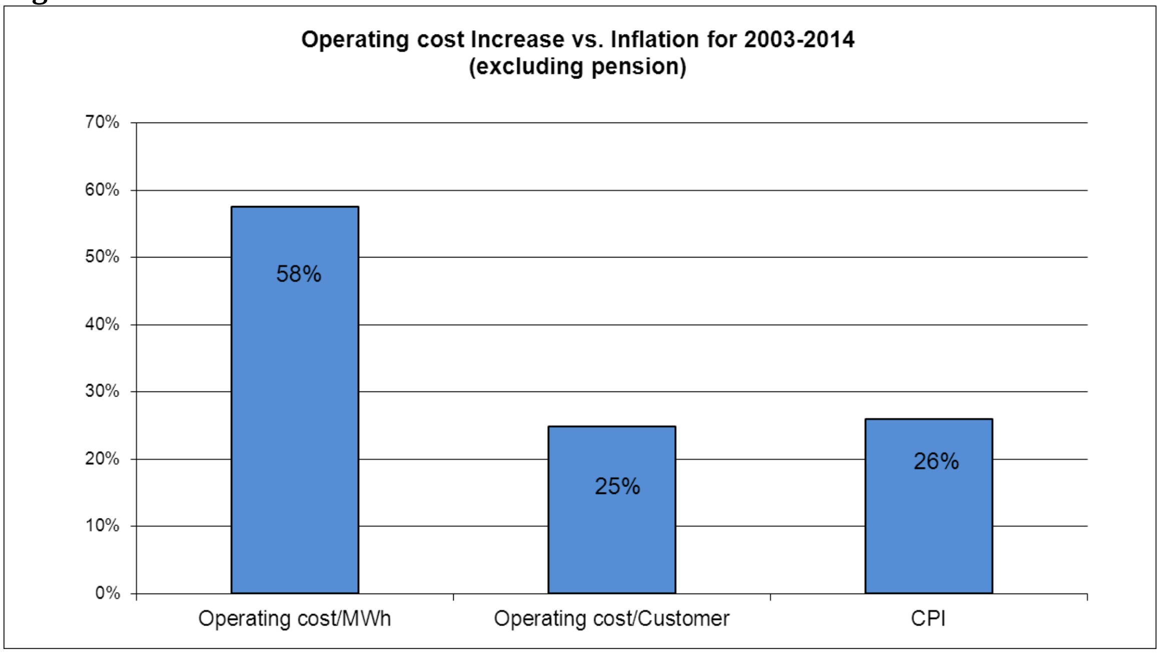
Operating Cost Driver (in $M)	2013 vs. 2012C	2013 vs. 2014
Vegetation management	3.4	-
Storm response	5.5	-
New renewable project operating costs	5.4	0.7
Lingan Transformation	(4.1)	-
Electric revenues write-offs and allowances for bad debt	2.0	-
Pension expense	17.8	(1.7)
Labour costs*	(2.6)	3.0
Other (net of savings)	6.0	2.1
Total change to Operating costs	33.4	4.1

*Note: Labour costs are net of administrative overheads, corporate allocations and include wage increases for both union and non-union groups, changes in FTEs, a portion of pension, and also excludes labour costs associated with increased storm, Lingan transformation and New renewable project operating costs.

As Figure 6-2 shows, assuming the costs requested in this Application are approved, our operating costs per customer for the period 2003 to 2014, will have increased at a lower rate than the Consumer Price Index (CPI). Operating costs per MWh appear to have increased significantly faster than CPI, but this reflects the decreased load associated with our two largest industrial customers. Generation will have decreased 12.9 percent between 2003 and 2014.

NS Power has a lower operating cost per customer than its vertically integrated comparables and has demonstrated a constant trend profile over the period as depicted in Appendix A. In addition, relative to its vertically integrated utility peers, NS Power has the lowest operating cost per MWh and has demonstrated a favourable trend profile.

Figure 6-2



NS Power now soon faces the most challenging phase of the transformation of our electricity system. Sales volumes have decreased while we have built and contracted for extra capacity to meet the Renewable Electricity Standards and greenhouse gas reduction requirements. As the transformation continues, we will make less use of our solid fuel plants but we are not able to shut any of them down entirely just yet because this could leave us unable to serve peak demand. Stable generating capacity from the legacy fleet is required to back-up the variable nature of our current renewable portfolio. This situation contributes to our increasing cost per MWh.

Making less use of our coal plants will increase their cost per unit of output. There is no question that the combination of building new renewable generation, and operating our legacy coal plants at higher unit costs, is putting upward pressure on overall operating costs. Over the long-term, however, the transformation we are undertaking will lead to costs that are lower and more stable compared to alternative strategies.

NS Power is working hard to manage costs during this transformation. Lower fuel expenses due to greater use of renewables and natural gas will help and so will our comprehensive approach to generation planning, always seeking the best strategy for managing our generating capacity in these circumstances. It was this planning that led the decision to operate two of Lingan's four units seasonally, starting in 2012.

A single-minded focus on operating cost savings could result in higher fuel costs to customers. It would be imprudent to jeopardize generation efficiencies to achieve operating cost reductions.

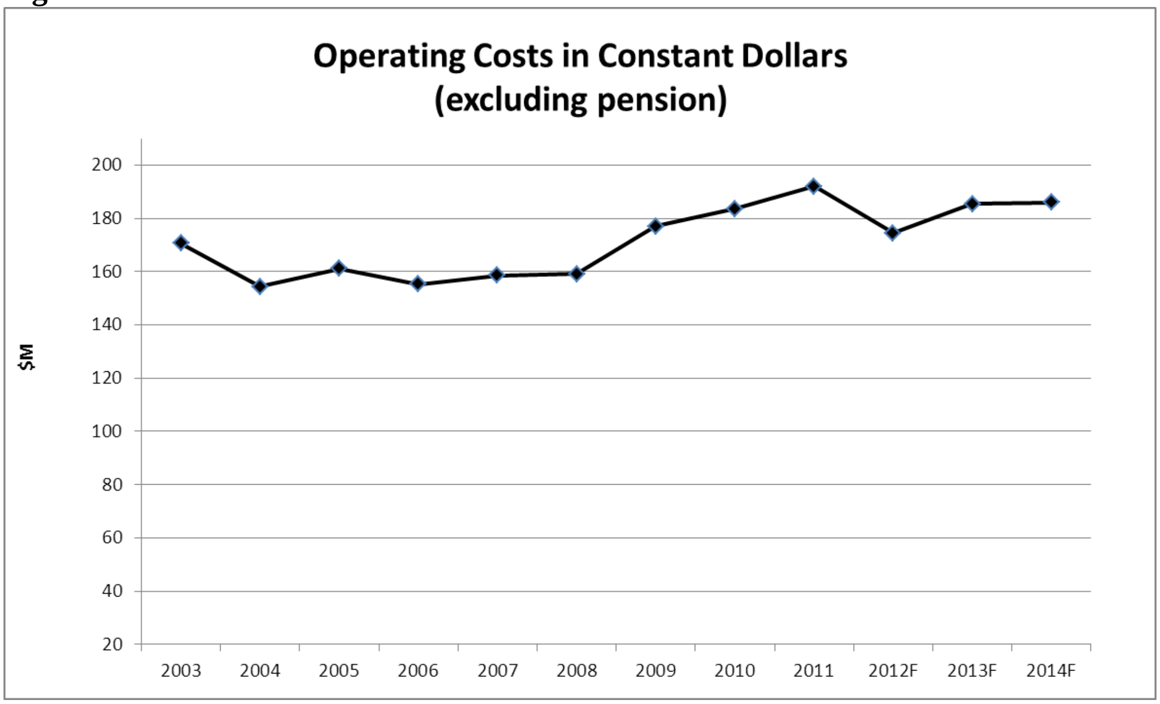
In our General Rate Applications, and various reviews by the Board, we have provided customers with detailed information about NS Power's operating costs. This transparency has included line-by-line analyses of operating costs, with variance explanations across all divisions, and expert studies commissioned by the Board and by NS Power. Studies have examined our operating costs, pension expenses, operating and maintenance practices for transmission and distribution, customer communications processes, vegetation management practices and spending levels.

Intervenors and the Board have had access to our collective agreement with the International Brotherhood of Electrical Workers. The Board's consultants have audited our affiliate transactions, and reviewed operating costs for power production, customer operations, customer service, regulatory affairs, and executive compensation.

The Liberty audit conducted in connection with the 2010 Fuel Adjustment Mechanism included a review of plant operations and concluded that our plants were generally well run and well maintained compared to similar plants in other jurisdictions.

Effective cost control has kept operating costs fairly stable in constant dollars since 2003, even as we invest in and operate renewable assets, storm-related outage response, and vegetation management, as outlined in the following chart.

Figure 6-3



The stabilization of constant dollar operating costs is a significant achievement considering that over the same period:

- the average number of customers increased by 10 percent
- environmental management costs have increased
- we have implemented storm recovery and vegetation management investments
- we have added a new heat recovery turbine, a biomass plant and three wind farms

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

We have updated operating cost utility benchmarking metrics to better illustrate our position and trending relative to our industry peers. As depicted in Appendix A, we continue to perform well and have demonstrated favourable trending alongside our peers.

During 2011, we engaged UMS Group to review our operating costs through a benchmarking study. In our Standardized Filing, section OP-03 demonstrates that we continue to perform well by industry norms.

Outlined below are NS Power's requested operating cost increases for 2013 and 2014.

For additional information, please refer to the following standardized filing documents:

Figure 6-4

Code	Description	Code	Description
OP-02	Organization Chart	OE-02 - 09	OM&G Details
OP-03	Latest OM&G Review	OE-13	Dues and Professional Association Charges
FOR-08	Breakdown of OM&G Expenses		

6.2 Labour Related Increases

Labour related costs (net of administrative overhead related to capital projects and corporate allocations) account for $0.9 million of operating cost increases in 2013 and $3.0 million of operating cost increases in 2014. This amount includes the labour component of our increased investment in storms, new renewable operations costs and savings related to the Lingan transformation.

It takes many experienced and highly skilled people to run a large, complex electricity system, and people of this calibre are in great demand. The increases in labour costs shown in this Application result from increased market pressure on compensation we experience in this highly competitive market for industrial staff, professionals and tradespeople. To attract and retain employees, NS Power targets compensation levels around the 50th percentile of comparable businesses. This allows us to run an efficient and cost effective business while keeping costs as low as possible for customers.

After slowing in 2011, the labour market quickly rebounded to reflect continued demand on the skilled trades and professions. Economic opportunities such as the federal shipbuilding contract awarded in 2011, and continued industrial expansion in Newfoundland and Alberta, further stimulates the skilled labour market in Atlantic Canada. These economic drivers had an impact on labour rates settled in 2011 and the beginning of 2012, and we expect these trends to continue into 2013 and 2014, as reflected in our forecast wage increases.

NS Power negotiates wages for unionized employees with IBEW Local 1928 through a collective bargaining process. At the time of writing this Evidence, we are negotiating a new agreement with the union following the March 2012 expiry of NS Power’s 56-month collective agreement with the IBEW. It is important for customers that NS Power maintains positive relations with the IBEW to ensure we effectively manage and improve reliability for customers. The previous collective agreement recognized the increased competition for skilled trades, specifically the challenges associated with attracting and retaining such positions as Power Line Technicians and Power Engineers. As a result, the agreement established wage differentiation between skilled trades and other job classifications. This enables NS Power to offer competitive wage rates to specific trades without having to provide “across-the-board” increases to all union job classifications. We expect this trend to continue during our current negotiations.

The change in capital investments profile results in a $1.6 million increase in our Administrative Overhead credit in 2013 compared to 2012 GRA Compliance Filing and a further increase of $1.1 million in 2014 over 2013. Administrative Overhead is an amount credited to operating costs based on labour hours charged to capital projects, thereby reducing our operating costs. Administrative Overhead rates are set during the

Annual Capital Expenditure planning process. In 2013, this credit reduces the increase in labour costs by $1.6 million compared to the 2012 GRA Compliance Filing, and by a further $1.1 million in 2014.

6.3 Pension Costs

In 2013, our pension expense will increase to $58.6 million, an increase of $17.8 million over the 2012 GRA Compliance Filing. In 2014, we project pension expense to decrease by $1.7 million compared to 2013.

During the regulatory process for the 2012 General Rate Application, NS Power provided extensive detail about our pension expense. We continue to focus on managing current and future pension costs.

In the 2012 General Rate Application, NS Power's pension expense of $40.8 million was based on a discount rate of 5.5 percent and an assumed rate of return of 7 percent per year.[26] The 5.5 percent discount rate assumption was based on the December 31, 2010, discount rate, which was the "measurement date" used for the 2012 GRA Compliance Filing. For the 2013 and 2014 test years, the respective pension expense amounts of $58.6 million and $56.9 million are based on a discount rate of 4.5 percent and an assumed rate of return of 6.75 percent per year in both 2013 and 2014.

The 4.5 percent discount rate was determined by NS Power's actuarial consultant Morneau Shepell,[27] based on high quality bond yields at December 31, 2011, using the Canadian Institute of Actuaries Educational Note methodology discussed below. December 31, 2011, is the "measurement date" for 2013 and 2014.

[26] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011, page 116, lines 3.
[27] RB-02 – RB-16.

Three main factors contribute to the net $17.8 million increase in pension expense between the 2012 GRA Compliance Filing (2012C) and 2013:

- a total decrease of 100 basis points in the assumed discount rate increases our pension expense by about $17.3 million. Of the decrease, approximately one-half (50 basis points) is due to the drop in bond yields between the time of preparing the 2012C figures and the 2013 filing figures. The other half (50 basis points) is due to updating the discount rate calculation method to that outlined in the Educational Note published by the Canadian Institute of Actuaries in September 2011 (the "CIA Educational Note").[28]

- a reduction of 25 basis points in the assumed rate of return on plan assets increases pension expense by about $2.0 million. NS Power management reviewed the company's assumptions about the long-term return on assets. As part of this review, management considered the return assumptions used by other Canadian organizations for pension plan accounting purposes. Surveys indicate that, in recent years, rate of return expectations have slowly but steadily declined as plan sponsors take a more conservative view of market performance. After careful consideration, taking into account the Plan's asset mix of 65 percent equity and 35 percent fixed income investments, NS Power reduced the assumed rate of return from 7.00 percent to 6.75 percent effective January 1, 2012.

- a reduction of 25 basis points in the assumed inflation rate decreases pension expense by about $4.2 million. NS Power reviewed the assumed long-term inflation rate, taking account of account historical inflation rates and the inflation control targets of the Bank of Canada. We also considered the assumption used in

[28] Educational Note published September 20, 2011 by the Canadian Institute of Actuaries' Task Force on Pension and Post Retirement Benefit Accounting Discount Rates entitled, "Accounting Discount Rate Assumption for Pension and Post-employment Benefit Plans".

the valuation report for the Canada Pension Plan (CPP).[29] Based on this information, we reduced the assumed inflation rate from 2.5 percent to 2.25 percent, effective January 1, 2012.

- The remaining net increase of $2.7 million results from several 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.

The reduction in pension expense of $1.7 million between 2013 and 2014 primarily results from a higher expected return on assets. The expected interest on assets increases faster than the expected interest on obligations, due to the amount of projected company contributions made in 2013.

6.4 Operating Costs by Group

Operating cost changes among the operating groups are discussed in this section.

Appendix E provides a Detailed Variance Analysis comparing annual expenditures for the following filings: 2012 GRA Compliance, Compliance Restated, 2011 Actual, 2012 Forecast, 2013 Forecast and 2014 Forecast. This includes detailed explanations of all variances over $50,000.

The operating cost requirement in the 2012 GRA Compliance Filing reflects expenses included in rates under the 2012 GRA Settlement Agreement,[30] approved by the Board.

2012C has been restated to reflect the reclassification of revenues previously included in operating costs to other revenues. In the past, NS Power has netted certain revenues against operating costs.

[29] 25th Actuarial Report on the Canada Pension Plan as at December 31, 2009 published by the Office of the Superintendent of Financial Institutions Canada, Office of the Chief Actuary.
[30] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011.

The 2012 forecast represents NS Power's operating budget for the year (2012F). The 2013 and 2014 forecasts reflect the company's estimate for those years at the time of filing (2013F and 2014F) respectively.

Operating group costs account for about 87 percent of operating costs. The following describes the function of each of our operating groups:

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

- 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.

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

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

- The Sustainability group's primary responsibility is to lead the transformation from carbon intensive generation to a more balanced portfolio of energy sources.

The Corporate Support group and Corporate Adjustment costs are approximately 13 percent of the total operating costs.

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

- Corporate adjustments are credits and expenses that are not assigned to a specific business unit or functional area. These mainly include capital overhead contributions and certain payroll costs (including year-end payroll accruals and incentives).

Figure 6-5 shows a breakdown of the operating cost changes among the operating groups.

Figure 6-5

Operating Cost by Group (in $M)								
	2011A	**2012C Restated**	**2012F**	**2013F**		**2014F**		**Larger Variances (excluding pension and labour related variances)**
				Δ$M	**Δ%**	**Δ$M**	**Δ%**	
Power Production	105.3	103.2	107.2	111.6		113.6		$5.4M Biomass Project, ($4.1M) Lingan Transformation
				8.4	8.1	2.0	1.8	
Customer Operations	69.1	65.5	67.0	79.3		80.5		$5.5M Storm Response, $3.4M Vegetation Management
				13.8	21	1.2	1.5	
Customer Service	39.9	32.4	33.8	37.0		37.4		$2.0M Electric revenue write-offs and allowances for bad debt
				4.6	14	0.4	1.1	
Technical & Construction Services	13.6	13.3	13.7	14.4		14.6		
				1.1	8.3	0.2	1.4	
Sustainability	3.2	2.0	1.4	1.5		1.5		
				(0.5)	(25)	-	-	
Corporate Support Group	49.9	47.3	48.7	52.1		53.1		
				4.8	10.1	1.0	1.9	

Operating Cost by Group (in $M)								
	2011A	2012C Restated	2012F	2013F		2014F		Larger Variances (excluding pension and labour related variances)
				Δ$M	Δ%	Δ$M	Δ%	
Corporate Adjustments	(19.6)	(18.0)	(17.4)	(16.9)		(17.6)		$1.7M Workforce reduction ($1.6M) Administrative overheads (2013) ($1.1M) Administrative overheads (2014)
				1.1	6.1	(0.7)	(4.1)	

Appendix F contains a detailed variance analysis for each operating group. Pension and labour variances were discussed above. The following sections discuss the other significant components of the variances.

6.4.1 Biomass Project (Power Production)

In April 2013, the Biomass project in Port Hawkesbury will go into service, with forecast operating costs of $5.4 million.

The Port Hawkesbury biomass unit is a 60 MW biomass cogenerating facility located on the former NewPage Port Hawkesbury site. The Biomass facility will provide firm renewable energy to further diversify the renewable portfolio. The added costs will cover the operating, maintenance, and management of this facility.

NS Power's original application for approval of the Biomass project estimated the cost of operating this plant at $3.3 million, based on the assumption it would operate in conjunction with the NewPage Port Hawkesbury mill.[31] During the application process, NS Power informed stakeholders it would cost more than double to run the plant on a standalone basis.[32] We have since reduced that estimate to $5.4 million, based on nine months of operation in 2013. In 2014, NS Power estimates the cost of operating the plant for a full year at $6.1 million, or $6.3 million including inflation.

[31] NSPI Port Hawkesbury Biomass Project, Capital Work Order Application, CI 39029, NSUARB-NSPI-P-128.10, April 9, 2010.
[32] NSPI Port Hawkesbury Biomass Project, NSPI(CA) IR-09 REVISED, NSUARB-NSPI-P-128.10, June 7, 2010.

6.4.2 Lingan Transformation (Power Production)

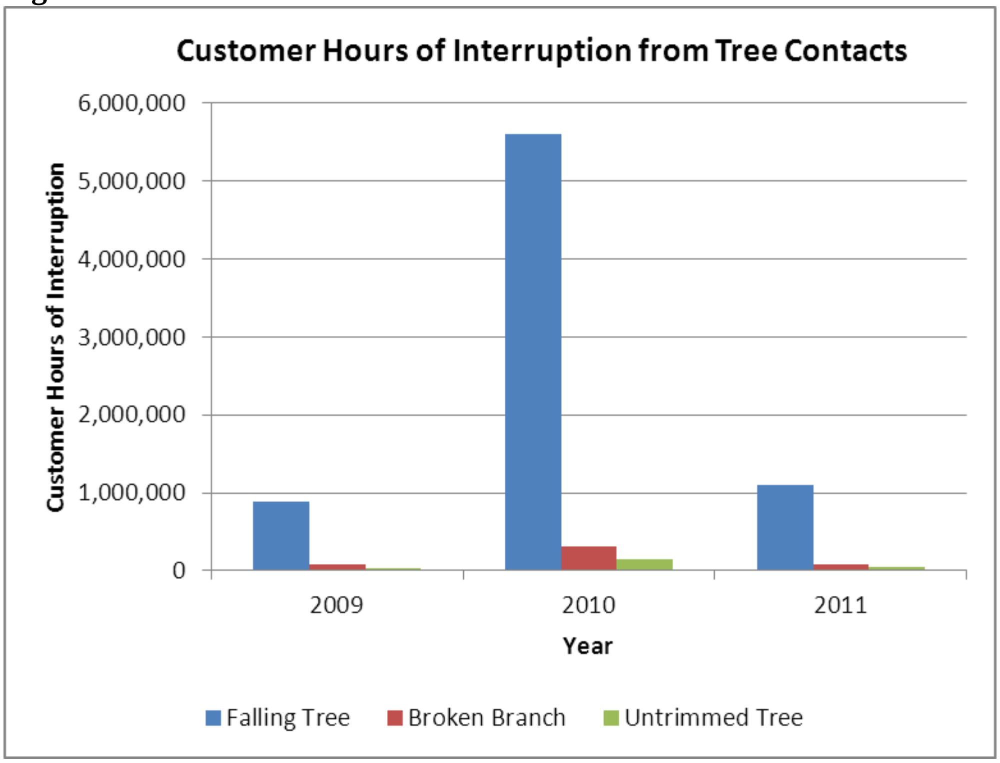
With the loss of pulp and paper industry load and changes in environmental regulations, NS Power undertook a generation study to review the optimization of our generation fleet. As a result of this review, NS Power concluded that two of the four units at Lingan would operate seasonally. This produces savings of $4.1 million.

NS Power's transformation from solid-fuel-based generation to cleaner, local and renewable energy sources has a significant impact on the role of our legacy generation plants in 2013 and 2014. The Lingan plant is transitioning from providing base load to operating two of its four units on a seasonal basis. This will provide unit flexibility and reliability during the winter, while reducing the plant's overall operating expense. The loss of pulp and paper industry load in 2011, combined with the addition of renewable energy, will reduce loads at our remaining fossil fuel plants. The change means that these units, which are designed to operate almost continuously, will operate at less than optimal capacity, and will turn on and off more frequently. The operation of hydro units, meanwhile, will follow system load more closely, to match a more variable generation protocol.

6.4.3 Vegetation Management (Customer Operations)

NS Power seeks an additional $3.4 million in 2013 for vegetation management to manage trees growing outside of our rights-of-way that can fall on our power lines within our rights-of-way. Our Vegetation Management Program is the most effective investment to improve customer reliability. Trees that are not managed in advance through right-of-way clearing programs can fall onto power lines during severe windstorms, causing outages. These hazard trees continue to be a significant source of power interruptions during severe storms. From 2009 to 2011, falling trees caused 7.6 million customer hours of interruption (see Figure 6-6).

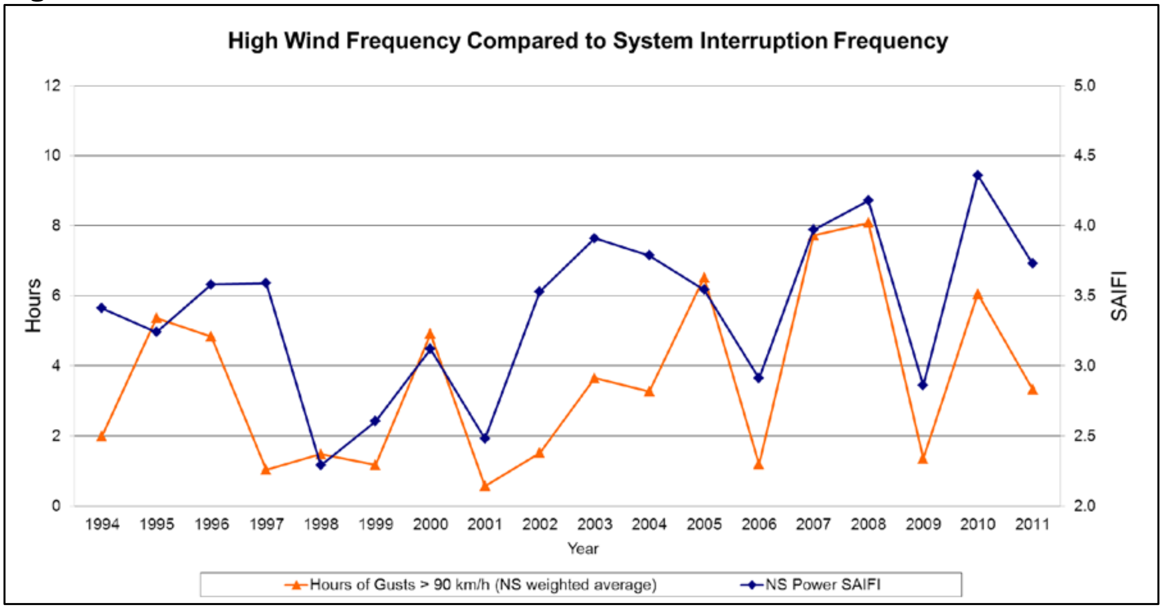
Figure 6-6



6.4.4 Storm Response (Customer Operations)

Increases in storm costs and vegetation management relate directly to the increased frequency and severity of weather experienced in Nova Scotia, in particular, high winds. Figure 6-7 shows this trend. The frequency of high winds results in higher storm response costs, and a need for increased investment in vegetation management.

Figure 6-7



SAIFI, which is sometimes referred to as SAIF Index, stands for the *System Average Interruption Frequency Index*. The measure is a standard reliability metric that is used in the utility industry in Canada and around the world, and is calculated by totalling customer interruptions divided by total number of customers.

The weather in Nova Scotia has steadily worsened over the last decade, with a significant increase in the frequency and severity of storms, and a corresponding increase in the number of unplanned power interruptions. The vegetation management program, which does not currently include additional money for trees outside the right-of-way, is progressing well with a significant proportion of the province having been completed. Increasing the funding available to include trees outside the right-of-way would strengthen this program. That enhancement is needed to storm-harden NS Power's system, and will further improve customer reliability.

NS Power remains strongly committed to its Emergency Services Restoration Plan (ESRP). Developed after Hurricane Juan, the plan established processes that quickly respond to power system damage caused by severe weather. Each year, NS Power carries out drills to test the plan's capability and train employees. The 2011 exercise scenario, conducted on July 6, was a “major winter storm with significant wind, snow and freezing rain.” NS Power filed the Emergency Services Restoration Plan annual update with the Board at the end of August 2011.

NS Power activated its plan for three major storms in 2009 and two in 2010. In 2011, NS Power activated the plan for the following three storms:

- January 11 – Province-wide snow storm
- June 2 – Province-wide lightning storm
- November 23 – Province-wide snow storm

NS Power's Emergency Operations Centre proved effective in coordinating resources to shorten the duration of outages caused by these storms and providing customers and the provincial Emergency Management Office with timely information on restoration.

The NS Power's ESRP has proved to be an effective system for responding to severe weather. In the first 10 days of November, 2010, some 232.8 mm of rain fell, with 110 mm falling on November 6 alone. This caused water levels to rise rapidly, exceeding the capacity of many reservoirs and the flow rates of several rivers, especially in Tusket. NS Power established a remote Emergency Operations Centre in Yarmouth to coordinate the Company’s personnel and contractor crews. Their efforts were instrumental in mitigating flooding effects and reducing damage to property and infrastructure. The event clearly demonstrated the value of having a well-thought-out and practiced response plan to these extreme weather events.

The increase in the severity of Nova Scotia’s weather has increased the costs associated with storm response and restoration. Current rates include annual storm costs of $5 million. Figure 1-7 details actual storm costs for the past five years:

Figure 6-8

Year	Storm Operating Expense ($M)	Storms Greater than $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 13th Wind event – $2.7 million
2011	6.6	January 11th event - $1.2 million October 30th event - $1.0 million December 8th event - $1.0 million

Over the last five years, annual storm response costs average $9.8 million in 2011 dollars, or $10.3 million in 2013 dollars. When we developed the 2013 forecast, we did not yet have the actual 2011 storm expense, so our forecast used a figure of $8 million for that year, which yields $10.5 million on average in 2013 dollars. Accordingly, NS Power is requesting an increase of $5.5 million for the storm response program in 2013, bringing total storm costs to $10.5 million, which is in line with NS Power's experience over the last five years.

6.4.5 Electric Revenues Write-offs and Allowances for Bad Debts (Customer Service)

Write-offs and allowances associated with defaults on electricity bills have increased to reflect actual experience. Actual write-offs over the last three years, excluding any one time large customer write-offs, are as follows:

Figure 6-9

Year	Actual Write-offs Expense ($M)
2009	6.2
2010	5.2
2011	6.6

Over the last three years, average annual gross write-off costs averaged $6 million. In 2011, actual net bad-debt costs totalled $5 million (excluding any one time large customer write-offs). Rates currently include $3.7 million in net bad debt costs.

Accordingly, in this Application, NS Power is seeking $5.7 million in net bad debt costs, a net increase of $2 million over the 2012 GRA Compliance Filing. This figure reflects actual write-off experience and forecast increases associated with higher electricity rates, offset by expected recoveries.

NS Power retained a consultant and based on their recommendations, the company has implemented improved bad-debt management practices, including expedited collection agency involvement. We expect these improved processes to reduce net bad debt costs from 2012 onwards, and the impacts of these improvements are included in the 2013 and 2014 forecasts.

6.4.6 Administrative Overheads (Corporate Adjustments)

Increases in administrative overheads of $1.6 million in 2013 compared to the 2012 GRA Compliance Filing, and $1.1 million in 2014 compared to 2013, result from the profiling of capital investment. Increased administrative overheads reduce operating costs.

6.5 Five Year Operating Cost Forecast

In this Application, NS Power has included a detailed five-year forecast summary of operating costs in Appendix G.

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

Figure 6-10 shows the estimated costs and percentage increases projected over five years.

Figure 6-10

	2012F	2013	2014	2015	2016	2017
Operating costs (in $M)	254.5	279.0	283.1	277.8	283.4	290.8
Increase (in $M)	-	24.5	4.1	(5.3)	5.6	7.4
% Change	-	9.6	1.5	(1.9)	2.0	2.6

The underlying assumptions in the five year operating costs forecast are:

- wage – increases for both union and non-union employees
- fleet fuel – 2015: 4.0 percent; 2016: 2.3 percent; 2017: 2.5 percent increase per annum
- employee related expenses (other than labour) increase – 2015: 1.51 percent; 2016 and 2017: 1.16 percent per annum
- pension costs – an increase in 2013 and a decrease in years 2014-2017
- contract costs – estimates based on individual circumstances or 2015: 1.51 percent; 2016 and 2017: 1.16 percent
- insurance costs – 5.0 percent annual escalation based on current insurance market
- corporate cost allocations – remaining consistent with 2014 percentages
- vehicle and administration overhead calculation – capital spend estimates consistent with the estimated capital expenditures
- remaining property costs – 2015: 1.51 percent; 2016 and 2017: 1.16 percent per annum
- all other significant costs – 2015: 1.51 percent; 2016 and 2017: 1.16 percent per annum
- no unforeseen regulatory mandates
- no change in environmental laws and regulations

Readers should treat these forecasts with caution as any change in forecast assumptions or actual experience can have a material effect on the forecast costs, as each year’s costs are estimated based on previous years’ estimates.

7 DEPRECIATIONAND REGULATORY DEFERRALS

7.1 Overview

NS Power owns many large, expensive assets that enable us to generate and distribute electricity. As with any business, we depreciate these assets over a period that approximates their useful lifespan. A fraction of each asset's original cost is treated as an expense each year until the asset is fully recovered.

From time to time, the Board allows us to build or acquire an asset, or incur some other business expense, but does not immediately include the expense in the rates it permits us to charge. The Board may defer certain legitimate charges so as to smooth changes in customer rates. When that happens, the deferred charge is considered to be a *regulatory asset*. It's an amount we know we will be able to recover in the future. And like any other asset that is not consumed in a single year, it must be depreciated, or amortized, over a time period for recovery in rates. This is known as *regulatory amortization*.

This section outlines the expenses NS Power seeks to recover through 2013 and 2014 customer rates for physical assets and regulatory assets. As with interest charges, a small change in the rates used to depreciate a multi-million dollar asset over several decades can have a large impact on the company's costs.

We have based the depreciation expenses in this Application on depreciation rates established in the 2011 Settlement Agreement with stakeholders, which the Board approved on May 11, 2011.[33] We have applied these rates to existing property, plant, and equipment, plus any net additions to them since rates were last set in 2012.

For regulatory assets, with two exceptions, the Board has previously approved the regulatory amortization expenses we seek to include in the 2013 and 2014 revenue

[33] NSPI 2010 Depreciation Study, UARB Order, NSUARB-NSPI-P-891, May 11, 2011.

requirement. One exception is the cost associated with the early retirement of non- Light-emitting Diode (LED) streetlights that are replaced, in accordance with provincial legislation, before the end of their useful life (known as a *stranded cost*). The other is the amount associated with deferring the recovery of certain fixed costs in 2012 as approved by the Board (the *Fixed Cost Recovery deferral*) but not yet reflected in rates.

We ask that recovery of these previously deferred expenses continue in 2013 and 2014. Our traditional analysis of revenue requirement forecasts that the recovery of the Fixed Cost Recovery deferral will begin in 2013, however the Rate Stabilization Plan proposes that the Fixed Cost Recovery deferral continue, in part, through 2013 and 2014. In the case of the non-LED streetlight stranded costs, we ask that recovery of these costs continue to be deferred until a final decision is made about how the deployment of LED streetlight is to be handled in rates.

This section covers the following:

- Tax regulatory amortization
- Demand Side Management (DSM) regulatory amortization
- Vegetation Management regulatory amortization
- Fixed Cost Recovery deferral
- Non-LED streetlight stranded costs

In 2013, depreciation expenses will increase by $17.5 million from the 2012 GRA Compliance Filing.[34] In 2014, depreciation expenses will increase a further $9.5 million. In calculating these expenses, we used depreciation rates approved by the Board on May 11, 2011. The total increase reflects net additions to property, plant, and equipment, net of plant asset retirements, since general electricity rates were last set.

[34] NSPI 2012 General Rate Application, Compliance Filing, NSUARB-NSPI-P-892, December 09, 2011.

In 2013, expenses for amortization of regulatory assets, including the Fixed Cost Recovery deferral amortization, will increase by $17.8 million. In 2014, these expenses will decrease by $800,000.

In calculating the regulatory amortization, we used a levelized revenue requirement approach for the tax amortization and a straight line approach for DSM and Vegetation Management. Amortization of the Vegetation Management asset will be complete at the end of 2013. The amortization of the Fixed Cost Recovery asset is reported on a distinct line in the statement of earnings as Fixed Cost Recovery adjustment. In calculating this expense, we used a straight line approach, with recovery over a three-year period, with interest applied to the outstanding balance. The Rate Stabilization Plan proposes that the Fixed Cost Recovery deferral continue to grow through 2013 and 2014, and then be recovered over an eight year period beginning in 2015.

For additional information, please refer to the following standardized filing documents:

Figure 7-1

Code	Description	Code	Description
DA-01	Depreciation Rates	DA-03	Amortization Expense
DA-02	Accumulated Reserve for Depreciation	DA-04	Asset Retirement Obligations (ARO) Reserve

7.2 Additions to Plant

In 2013, depreciation expenses will increase by $17.5 million over the 2012 GRA Compliance Filing. In 2014, depreciation expenses will increase by another $9.5 million. These increases result from capital additions to plant in service, as filed in the approved Annual Capital Expenditure (ACE) Programs, and other capital expenditures approved by the Board. In 2013, the total depreciable plant balance increased by about $315 million over the Compliance Filing, due to actual in-service additions in 2011, and additions forecast for 2012 and 2013. In 2014, we forecast a further increase in the depreciable plant balance of approximately $200 million.

Since general rates were last set in the 2012 GRA, our capital expenditures remain focused on transforming our generation portfolio and customer reliability. The capital outlook for 2013 and 2014 reflects the uncertainty we are managing in terms of energy demand, and increasingly restrictive air emission regulations. As detailed in the 2012 ACE Plan submission,[35] the capital plan includes:

- NS Power will make no new investments in wind energy for at least two years, therefore new wind projects if required will be developed in 2014/2015, and be in service in 2015, consistent with Renewable Electricity Standard regulations

- We will minimize investments in the Lingan Generating Station's Unit 2 to reflect the fact that this is the unit most likely to close under the scenario of reduced load, and in light of proposed federal greenhouse gas (GHG) regulations under the recently announced equivalency agreement to be made between the Federal Government and the Government of Nova Scotia.[36]

- We will defer future fast-acting generation until the renewable energy integration study is completed and we have more certainty around the introduction of additional wind generation.

NS Power's forecast capital spending for 2013 and 2014 (including work in progress) includes the following major multi-year projects that will contribute to NS Power's reliability and renewable energy additions:

- NewPage biomass project
- Light emitting diode (LED) street lighting replacement
- Transmission additions and system reliability improvements

[35] NSPI 2012 Annual Capital Expenditure Plan, NSUARB-NSPI-P-128.12, November 2, 2011.
[36] Environment Canada News Release, Halifax, NS, March 19, 2012: http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=C57FE6E9-8B0D-487E-8B31-58B3FE776DBC

- 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.

7.3 Regulatory Amortizations

As shown in Figure 7-2 regulatory amortizations in 2013 will increase by $17.8 million over the 2012 GRA Compliance Filing and then decrease by $800,000 in 2014.

Figure 7-2

Amortizations	2012C ($M)	2013 ($M)	2014 ($M)
Section 21	$16.2	$17.3	$18.5
2005 Q1 tax	2.2	2.4	2.6
DSM	2.2	2.2	1.1
Vegetation Management	1.0	1.0	-
Non-LED Stranded Cost	-	-	-
Sub-total	21.6	22.9	22.2
Fixed Cost Recovery	-	16.5	16.5
Total	$21.6	$39.4	$38.7

Figure 7-2 reflects:

- An increase of $1.1 million in 2013, and $1.2 million in 2014 related to Section 21 taxes, associated with the eight-year levelized approach.

- An increase of $0.2 million in 2013 and $0.2M in 2014 related to the deferral of income taxes applicable to Q1, 2005, based on an eight year levelized approach.

- A decrease of $1.1 million in 2014 related to completion of the amortization of deferred demand side management expenses.

- A decrease of $1 million in 2014 related to the conclusion of the deferred vegetation management expenses.

- An increase of $16.5 million in 2013 related to recovering the Fixed Cost Recovery deferral over a three year period beginning in 2013.

7.3.1 Section 21 Amortization

The Section 21 amortization reflects the amortization of deferred costs pertaining to pre-2003 income taxes that have been paid, but not yet recovered from customers, as a result of capital cost allowance deductions we claimed in our corporate income tax return that were disallowed in a Supreme Court decision.[37] NS Power applied to the Board, and received approval, to include recovery of these costs in customer rates. The Board directed that recovery would commence in 2007 over an 8 year amortization period.[38] As part of the 2007 GRA, the Board approved recovery of this regulatory asset in rates over eight years, beginning April 1, 2007.[39]

NS Power reached an agreement with stakeholders on its calculation methodology used for regulated ROE in January 2010. Under this agreement, NS 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 the Company to recognize additional amortization amounts in current periods, and reducing amounts in future periods. This helps to provides rate stability for customers. The Board approved the agreement.[40] As part of its approval of the 2012 GRA Settlement Agreement, the Board approved a continuation of the agreement to allow NS Power flexibility in using this regulatory asset.[41] At the beginning of 2012, NS Power had $14.9 million in Section 21 carryover amounts to apply on a discretionary basis. We plan to use the full amount in 2012. The 2013 amortization reflects the base amount of Section 21 assets of $40.7 million for 2013.

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[37] *Nova Scotia Power Inc.* v.*Canada*, 2004 SCC 51, [2004] 3 SCR 53.
[38] NSPI 2005 General Rate Application, UARB Decision, NSUARB-NSPI-P-881, March 31, 2005, page 153, paragraph 326-328.
[39] NSPI 2007 General Rate Application, UARB Decision, NSUARB-NSPI-P-886, February 5, 2007.
[40] UARB Order Approving ROE Settlement Agreement, NSUARB-NSPI-P-888(2), January 20, 2010.
[41] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011, page 13.

Figure 7-3 shows the reconciliation of the Section 21 tax regulatory asset.

Figure 7-3

Section 21 Taxes	$M
December 31, 2011 balance	42.0
2012 amortization, based on UARB approval	(16.2)
2012 discretionary carryover credit	14.9
December 31, 2012 balance	40.7

Figure 7-4 shows the amortization schedule based on the Section 21 deferred balance.

Figure 7-4

Year	Amortization ($M)	Tax Effect of Amortization ($M)	Carrying Cost ($M)	Total ($M)
2013	17.3	7.8	3.1	28.2
2014	18.5	8.3	1.4	28.2
2015	4.9	2.2	0.1	7.0

7.3.2 2005 Q1 Tax Amortization

The Board agreed to allow NS Power to defer taxes not reflected in rates for the period January 1, 2005, until April 1, 2005, the date when new rates became effective. As a result, we deferred $16.7 million, consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes. The Board approved recovery of this regulatory asset over eight years, beginning April 1, 2007.[42] The 2005 taxes included an amortization of $2.4 million in 2013 and $2.6 million in 2014 as shown in Figure 7-6. The total cost of $3.9 million in 2013 and 2014 remains constant for the recovery amortization period in accord with the levelized revenue requirement approach approved by the Board in the 2007 Rate Decision.

Figure 7-5 shows the reconciliation pertaining to 2005 Q1 Tax Amortization.

[42] NSPI 2005 Rate Case, UARB Decision, NSUARB-NSPI-P-881, January 21, 2005, paragraphs 326-328.

Figure 7-5

Q1 2005 Tax Amortization	$M
December 31, 2011 Balance	7.9
2012 amortization based on UARB approved schedule	(2.2)
December 31, 2012 balance	5.7

Accordingly, we have included $2.4 million of amortization of the 2005 Q1 deferred taxes in the 2013 revenue requirement and $2.6 million of amortization in the 2014 revenue requirement.

Figure 7-6

Year	Amortization ($M)	Tax Effect of Amortization ($M)	Carrying Cost ($M)	Total ($M)
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

7.4 Demand Side Management Amortization

In the 2009 Rate Decision, the Board approved the amortization of Demand Side Management expenditures for 2008 and 2009 over six years starting in 2009.[43] These programs help customers manage their electricity consumption and help participants lower their total energy spending.

The 2013 revenue requirement includes an annual amortization amount of $2.2 million for the deferred Demand Side Management expenditure. This entails no change to amounts included in 2012 GRA Compliance Filing. The 2014 revenue requirement reflects the final year for the amortization of Demand Side Management expenditures with an amortization expense of $1.1 million. This results in a decrease of $1.1 million over 2013.

[43] NSPI 2009 General Rate Application, UARB Decision, NSUARB-NSPI-P-888, November 5, 2008.

7.5 2008 Vegetation Management

In the 2012 GRA, NS Power proposed amortization of the 2008 Vegetation Management deferral over two years. This was approved by the Board through the 2012 GRA Compliance Filing in rates commencing on January 1, 2012.[44]

The 2013 revenue requirement reflects the final year for the amortization of the deferred Vegetation Management expenditures with an amortization expense of $1 million. This entails no change to amounts included in 2012 GRA Compliance, and a decrease in the 2014 revenue requirement of $1 million over 2013.

7.6 Non-Light-emitting Diode Streetlight Stranded Cost

In 2011, the province passed the Energy Savings Roadway Lighting (2011) Act,[45] which authorizes regulations requiring roadway lighting to meet designated efficiency standards. On April 25, 2012, the provincial government announced[46] draft regulations which are currently undergoing public consultation. The draft regulations would require large-scale deployment of light emitting diode (LED) streetlights to be completed by June 19, 2019.[47] The LED technology will replace all mercury vapour streetlights and the related asset class of mercury vapour based streetlights will be eliminated. As part of the LED streetlight implementation, the mercury vapour units will be retired from service, but with a remaining net book value. The end of an asset class creates a stranded asset, if not fully depreciated. The associated net book value related to the retired mercury vapour assets units is set as a stranded cost and reported as regulatory asset. See table RB-2-16 line 13.

[44] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011.
[45] *Energy Savings Roadway Lighting* (2011) Act, R.S.N.S. c. 6, 2011.
[46] Press Release, Government of Nova Scotia, April 25, 2012, http://www.gov.ns.ca/news/details.asp?id=20120425003
[47] Draft Energy Efficient Appliance Regulations: http://www.gov.ns.ca/energy/publications/Draft-LED-Regulations-2012-tracked-changes_2.pdf

At the time of filing this Application, NS Power's Capital Work Order Application has not yet been filed, pending final government regulations to implement the LED streetlight program. Remaining issues relating to LED streetlight deployment and the potential for stranded costs and conversion fees, are better resolved during that capital work order process, when more will be known about the program and its related costs. NS Power is proposing to defer amortization of the non-LED stranded cost until a final determination is made of the rates treatment and early retirement issues concerning LED streetlight deployment.

7.7 Fixed Cost Recovery Deferral

Uncertainty associated with the operation of our largest pulp and paper customers and their contribution to load prompted a deferral recovery mechanism. As part of the 2012 GRA Decision, the Board approved the Fixed Cost Recovery deferral, which provided for any amount of unrecovered forecast contributions to fixed costs from these customers to be deferred for recovery beginning in 2013.[48]

The Board's Decision stated:

> Given the continuing uncertainties surrounding these customers and the fact that the Board has amended the LRR from that originally applied for, the Board believes it appropriate to defer the impact of the LRR on other customers, using the GRA Agreement deferral mechanism, until 2013.
>
> [217] Therefore, the Board directs that the lost contribution to non-fuel costs (net of non-fuel variable O&M costs) as a result of implementing the LRR will be deferred for later recovery in the same manner as described in paragraph 2 of the GRA Agreement.[49]

[48] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011, page 77, paragraph 217.
[49] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011.

NS Power has projected the balance of the Fixed Cost Recovery deferral to be $44 million by the end of 2012. We are proposing to amortize the Fixed Cost Recovery deferral balance with associated interest over three years beginning in 2013. The amortization amount for 2013 and 2014 is $16.5 million. The Rate Stabilization Plan proposes that the Fixed Cost Recovery deferral continue to grow through to the end of 2014, for recovery over an eight year period beginning in 2015.

Associated with this Fixed Cost Recovery deferral, NS Power requests a change to our Accounting Policy and Proceedure 5900 – Income Taxes. We are requesting the Board allow us to account for these deferrals on a deferred tax basis, in order to align tax expense with the deferral recovery period. This is the best accounting approach for customers. It is how the accounting presently works for the 2010 FAM Deferral. Further details relating to this request, including the requested changes to the accounting policy are included as Appendix Q.

8 RATE BASE

8.1 Overview

Rate base is a regulatory term for the value of all the assets NS Power uses to generate and distribute electricity. It includes physical items, like power plants, wind turbines, power lines, and inventories of fuel and other supplies. It also includes financial assets, such as working capital and regulatory assets. (Regulatory assets are costs the Board has approved, but which have not been recovered through rates, and therefore appear as deferred items on the Company's balance sheet.) Establishing the rate base is an important element in determining NS Power's revenue requirement, which in turn plays a central role in setting rates.

This Application uses the same Board-approved method for calculating the rate base as our last four General Rate Applications.

In 2013, the average rate base will rise to $3,587.8 million, approximately $77 million higher than the 2012 GRA Compliance Filing (the latest approved figure). In 2014, it rises to $3,616.5 million, an increase of $29 million. Several factors contribute to these increases:

- average capital assets increase by $23 million in 2013 and $87 million in 2014
- average net working capital increases by $11 million in 2013, but decreases by $15 million in 2014
- average deferred charges and credits increase by $48 million in 2013, but decrease by $40 million in 2014
- average materials and supplies decrease by $5 million in 2013, and by $4 million in 2014

Figure 8-1 sets out the components of NS Power's average rate base for the 2013 and 2014 test years, calculated in a manner consistent with the Board's Rate Decisions in 2006, and subsequent decisions.[50] We have provided details in RB-02 to RB-16 of this Application.

Figure 8-1

Average Rate Base	2012C ($M)	2013F ($M)	2014F ($M)
Average capital assets	3,288	3,311	3,398
Average cash working capital allowance	59	52	56
Average Working capital adjustment (by agreement with stakeholders)	(27)	(9)	(28)
Average materials and supplies inventory	122	117	113
Average deferred charges & credits	69	117	77
Total	$3,511	$3,588	$3,616

For additional information, please refer to the following standardized filing documents:

Figure 8-2

Code	Description	Code	Description
SR-04	Lead-Lag Study	FOR-15	Average Rate Base - Working Capital
OP-04	Listing of Assets	RB-01	Plant Continuity Schedule
FOR-12	Average Rate Base - Assets	RB-02 - 16	Rate Base Details and Pension Expense
FOR-13	Average Rate Base - Charges / Credits	OR-07	Deferred Cost Recovery Mechanisms
FOR-14	Average Rate Base - Materials / Supplies		

8.2 Details of Rate Base

8.2.1 Average Capital Assets

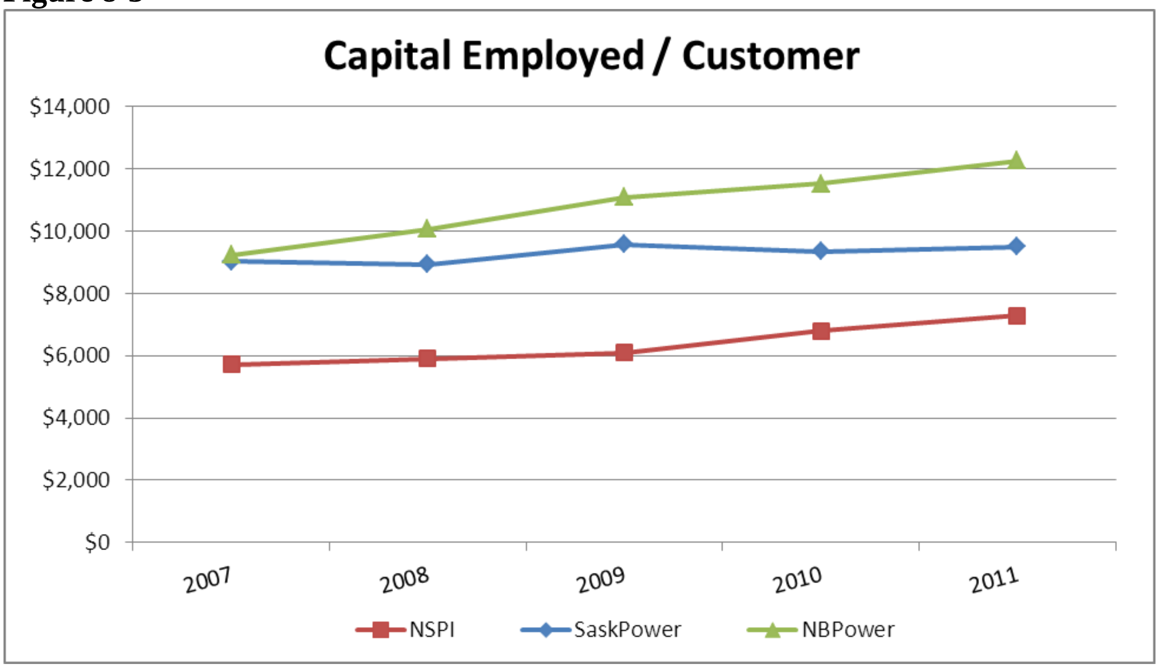
Average capital assets reflect NS Power's actual capital asset balances as of December 31, 2011, plus the items forecast for 2012 including projects submitted in our 2012 Annual Capital Expenditure Plan,[51] plus our projected capital programs for 2013 and 2014. These amounts are reduced by our accumulated depreciation as of December 31,

[50] NSPI 2006 General Rate Application, UARB Decision, NSUARB-NSPI-P-882, March 10, 2006.
[51] NSPI 2012 Annual Capital Expenditure Plan, NSUARB-NSPI-P-128.12, November 2, 2011.

2011, and our forecast depreciation in the years 2012, 2013, and 2014. More details appear in FOR-12 of this Application.

Average capital assets are rising steadily because NS Power is in a period of historic change. We are replacing expensive, imported, high-carbon fuels with investments in cleaner, local energy sources, many of them renewable. This is an investment in lower carbon emissions, a cleaner environment, and reduced dependence on imported coal. Environmental regulations have enabled NS Power to make great progress in renewable electricity generation in Nova Scotia. The growth in rate base continues to benchmark NS Power well next to its peers as depicted below. NS Power has the lowest capital employed per customer among its vertically integrated utility peer group in Canada.

Figure 8-3



NS Power's renewable generation includes new wind and biomass power, as well as hydro systems that have served the province for as much as a century. Over the longer term, this investment in new, local, renewable energy will help stabilize electricity prices by reducing our exposure to the volatility of imported coal costs. However, coal and natural gas continue to provide most our generation. Maintaining and improving NS

Power's thermal and hydro generating units helps preserve lower fuel prices, safety, performance and system stability.

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

8.2.2 Average Cash Working Capital Allowance

Cash working capital allowance represents the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items. These 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.[52]

In our 2013 and 2014 forecasts, we have applied an adjustment factor to retain the cash working capital allowance at the 2012 GRA Settlement Agreement level of $27.9 million.[53] This is presented in RB-2-16 (2013 and 2014), line 19 and 20.

8.2.3 Average Materials and Supplies Inventory

We have based our fuel and supplies inventory on the projected monthly average for 2013 and 2014, consistent with the methods used in the 2012 General Rate Application. The inventory consists mainly of coal and oil, thermal plant inventories, and transformers and conductors to support the transmission and distribution system.

[52] Refer to FOR-15, which contains Nova Scotia Power's calculations for working capital using the 2012 lead/lag methodology.

[53] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011, page 12.

The average materials and supply inventory included in our 2013 rate base forecast is $117, while that for 2014 is $113 million.[54] That's a decrease of $5 million in 2013 from the 2012 GRA Compliance Filing, and a further decrease of $4 million in 2014.

8.2.4 Deferred Charges and Credits

NS Power's method for calculating deferred charges and credits conforms to the 2006 through 2012 General Rate Applications. In those Applications, we included all components of the deferred charges and credits in our rate base calculation, and the Board confirmed this approach in all four Decisions. In 2013, NS Power included two new items in rate base: Fixed Cost Recovery deferral and non-LED streetlights stranded asset. They are discussed below.

Deferred charges represent amounts that NS Power has paid to operate the utility, but has not yet expensed. These amounts have not been reflected in customer rates. Such items are useful for a number of reasons. Deferred charges include such 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.

We forecast average deferred charges and credits of $117 million in 2013, and $77 million in 2014. That's an increase in 2013 of $48 million over the 2012 GRA Compliance Filing, followed by a decrease of $40 million in 2014. Figure 8-4 outlines NS Power's forecast average deferred charges and credits.

Figure 8-4

Deferred Charges & Credits	2012C Average ($M)	2013 Average ($M)	2014 Average ($M)
Defeasance & Finance Charges	76	76	66
Section 21 and 2005 Q1 taxes	56	35	14

[54] Refer to FOR-14.

Deferred Charges & Credits	2012C Average ($M)	2013 Average ($M)	2014 Average ($M)
Pension Asset	48	66	82
FAM Regulatory Asset	48	14	-
Fixed Cost Recovery Deferral	-	37	23
Non-LED Stranded Asset	-	3	7
Asset Retirement Obligations	(149)	(101)	(106)
Deferred Income Taxes	(15)	(13)	(4)
Other	5	--	(5)
Total	$69	$117	$77

The amounts included in rate base reflect a year-end average, consistent with the method approved by the Board in previous rate cases. The $48 million increase in 2013 is a result of:

- $21 million reduction due to amortizations of Section 21 and 2005 Q1 taxes
- $18 million increase in net pension assets
- $34 million decrease in FAM regulatory asset deferrals
- $40 million increase in FCR regulatory asset and non-LED stranded asset
- $48 million decrease in asset retirement obligation
- $2 million decrease in deferred income taxes associated with the FAM and FCR regulatory assets
- other decreases of $5 million

The $40 million decrease in 2014 is a result of:

- $10 million reduction due to amortizations of defeasance & financing charges
- $21 million reduction due to amortizations of Section 21 and 2005 Q1 taxes
- $16 million increase in net pension assets
- $14 million decrease in FAM regulatory asset deferrals
- $10 million increase in FCR regulatory asset and non-LED stranded asset
- $5 million increase in asset retirement obligation

- $9 million decrease in deferred income taxes associated with the FAM and FCR regulatory assets
- other decreases of $5 million

Further explanation of these assets is described below.

8.2.4.1 Defeasance and Finance Charges

Defeasance costs are included in average rate base as approved in the past four GRA Decisions. The reduction of $10 million in 2014 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 Board's 1993 Rate Decision.[55]

8.2.4.2 Section 21 and 2005 Q1 Taxes

As noted above, in the 2005 Rate Decision, the Board approved the inclusion of the Section 21 taxes in the rate base. Subsequently, the Board 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 allowed us to begin amortizing these assets. As a result, the average deferred balance for taxes has decreased in both 2013 and 2014. See Section 5.1 for further details.

8.2.4.3 Pension Asset

The average prepaid pension asset in 2013 increases $18 million over the 2012 GRA Compliance Filing, resulting in an average prepaid pension asset for 2013 of $66 million. In 2014, the average prepaid pension asset increases by $16 million to $82 million. This increase reflects the difference between the funding provided to the pension plan, less the amount expensed by NS Power as calculated by its actuary.

[55] NSPI 1993 General Rate Application, UARB Decision, NSUARB–NSPI–P-863, April 5, 1993, page 25.

For the 2013 and 2014 test years, NS Power forecasts pension funding at the minimum required amount of $73.4 million, while pension expenses are forecast to be $58.6 and $56.9 million, respectively.[56]

8.2.4.4 FAM Regulatory Asset

For 2013 and 2014, NS Power's fuel adjustment reflects the actual adjustment resulting from an under-recovery of fuel costs in prior periods. Interest is calculated on the outstanding rate base amounts.

8.2.4.5 Fixed Cost Recovery Deferral Regulatory Asset

As part of the 2012 GRA Decision, the Board approved the Fixed Cost Recovery deferral, which provided for any amount of unrecovered Extra Large Industrial customer contributions to fixed costs to be deferred for recovery from customers beginning in 2013.[57] Section 5.1 contains more details.

As with the Fuel Adjustment Mechanism, Fixed Cost Recovery deferral has an interest component, and deferred income tax is also calculated on the balance. The interest component is calculated using the weighted average cost of capital with semi-annual compounding as stipulated in the Fuel Adjustment Mechanism. Deferred income taxes are recorded in the statement of earnings based on the Fixed Cost Recovery deferral balance.

8.2.4.6 Non-Light-emitting Diode Streetlight Stranded Asset

The net book value related to the retired mercury vapour streetlights is set as a stranded cost and reported as a deferred charge and regulatory asset. NS Power is proposing to

[56] Refer to OE-02 – OE-09.
[57] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011, page 11, paragraph 16.

defer the amortization of the non-LED streetlight stranded cost until the capital work order application for the LED streetlight program has been determined by the Board.

8.2.4.7 Asset Retirement Obligations (ARO)

NS 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, we add a corresponding asset retirement cost to the carrying amount of the related asset. NS Power deducts the obligation from rate base.

8.2.4.8 Deferred Income Taxes

Deferred income taxes relate to the accounting treatment of income taxes related to the Fuel Adjustment Mechanism and Fixed Cost Recovery deferral.

9 CAPITAL STRUCTURE AND FINANCING

9.1 Overview

It takes a great deal of big plants and equipment to generate electricity and deliver it to Nova Scotians. Over the years, NS Power has built many large plants: thermal stations that burn coal, heavy fuel oil and natural gas to generate electricity; hydro dams; tidal generators; and more recently, wind turbines. We have built thousands of kilometres of transmission lines and thousands of kilometres of distribution systems, including substations, lines, poles, and all the equipment mounted on them.

These facilities have a long life expectancy, and their cost can only be recovered gradually, over a period of years or even decades. NS Power has to come up with the money to build them in advance. There are only two ways to do this:

- We can borrow money, and pay interest to the lender.
- We can use shareholders’ money, and pay them a return on their investment in the form of dividends.

In reality, we do some of both, and either way, there is a real cost required to get the up-front money that builds and sustains our electricity system.

In the case of borrowed money, bond markets determine the maximum amount of interest we pay, based in part on the financial health of the Company, and regulatory risk. The rating agency Standard and Poor’s (S&P) recently revised its outlook on NS Power from stable to negative based on “heightened regulatory risk” associated with the recovery of a “meaningful capital expenditure program.” [58]

[58] OP-12 Attachment 3, page 37.

In the case of shareholder money, the UARB determines the amount we can use, and the rate of return we can pay shareholders out of money received from rates. In many respects, shareholder return is analogous to the interest we pay to lenders; it is the cost of borrowing money from shareholders and using it to provide service to customers.

In practice, NS Power uses a combination of the two methods: roughly 60 percent of our capital comes from short and long term borrowing and preferred shares; up to 40 percent comes from shareholder investment. This is known as our *capital structure*. For rate setting purposes, shareholder investment is set at 37.5 percent.

One crucial aspect of the big transformation now underway to cleaner, local, renewable energy sources is a shift from fuel expenses to capital expenses. To free future generations of Nova Scotians from a risky dependence on increasingly scarce, imported, high-carbon fuels, we are building wind and hydro systems that generate electricity without fuel. As the years go on, we will buy less fuel, but spend more on interest and dividends to finance the renewable plants and equipment we're installing.

Instead of sending money overseas to buy high-carbon fuel whose future price is subject to volatility, we are investing in local plants and equipment to generate clean energy right here in Nova Scotia. To make those investments, we have to borrow money. To get a reasonable interest rate, NS Power must be financially sound. That's why it's in our interests – and our customers' interests – that NS Power remain a company to which banks and bondholders can lend with confidence, and from which shareholders can expect a fair rate of return on their investment. Otherwise, they can choose to invest their money elsewhere.

The bank loans and bonds that finance our new generating facilities will be paid off over a long period of time. An interest rate increase of even a fraction of a percentage point will add millions to the cost of power from one of these plants over its lifetime. Since the Board must, by law, base electricity rates on our costs, higher interest rates mean higher electricity rates. The rate of interest we pay depends on the expectation of 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. Standard & Poor's recent credit report suggested the agency had somewhat reduced confidence in NS Power's regulatory outlook.

As NS Power undergoes a major transformation from imported, high-carbon fuels to local renewables that are, in most cases, fuel free, our capital structure and financing costs take on greater prominence in rate setting. The transformation makes it more important than ever that investors and lenders see NS Power as financially healthy and stable.

For additional information, please refer to the following standardized filing documents:

Figure 9-1

Code	Description	Code	Description
OP-01	NSPI / Emera Regulated Annual Reports	FOR-07	Details of Fuel and Purchased Power
OP-12	Analyst / Bondholder Presentations	FOR-09	Breakdown of Revenue Requirement and Rate Increase
OP-13	Emera Proxy Statement	FOR-10	Average Capital and Cost of Capital
OP-15	Quantities / Classes of Shares	FOR-11	Interest Charges
FOR-01	Regulated Statement of Earnings	OR-04	Unregulated Revenues
FOR-02	Regulated Balance Sheet	OR-06	Sharing Mechanisms
FOR-03	Regulated Statement of Retained Earnings	OE-10 - 11	Taxes
FOR-04	Regulated Statement of Cash Flows	OE-12	Foreign Exchange Hedging
FOR-06	GWh Production and Sales		

9.2 Credit Ratings

A *credit rating* is an independent agency's opinion of a company's creditworthiness – its ability to pay its debts on schedule. It is the single most important factor influencing risk assessments of bonds and bank loans.

Throughout the recent financial crisis, NS Power has been able to successfully access short term debt markets. However, Standard & Poor's recent change to NS Power's outlook to negative from stable could affect our access to capital 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. NS 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 NS Power and its customers must avoid.

9.2.1 Nova Scotia Power's Ratings

Figure 9-2 compares NS Power's credit ratings with those of other regulated Canadian utilities.

Figure 9-2

Regulated Canadian Utility	Dominion Bond Rating Service	Outlook	Review Date	S&P Rating[1]	Outlook	Review Date
Altalink L.P[2]	A	Stable	Feb 2011	A-	Stable	Nov 2010
CU Inc.	A (high)	Stable	Mar 2012	A	Stable	Jul 2011

Regulated Canadian Utility	Dominion Bond Rating Service	Outlook	Review Date	S&P Rating[1]	Outlook	Review Date
ENMAX Corp.	A (low)	Stable	Jan 2012	BBB+	Stable	Sep 2010
EPCOR Utilities Inc.	A (low)	Stable	Jul 2011	BBB+	Stable	Dec 2011
Maritime Electric Co. Ltd.[3]	---	---	---	BBB+	Stable	Dec 2010
Nova Scotia Power	A(low)	Stable	Mar 2012	BBB+	Negative	Mar 2012
Enbridge Inc.	A(low)	Stable	Dec 2011	A-	Stable	Dec 2011
TransAlta Corp.	BBB	Stable	Sep 2011	BBB	Negative	Aug 2011
Fortis Inc.	A (low)	Under Review	Feb 2012	A-	Negative	Feb 2012

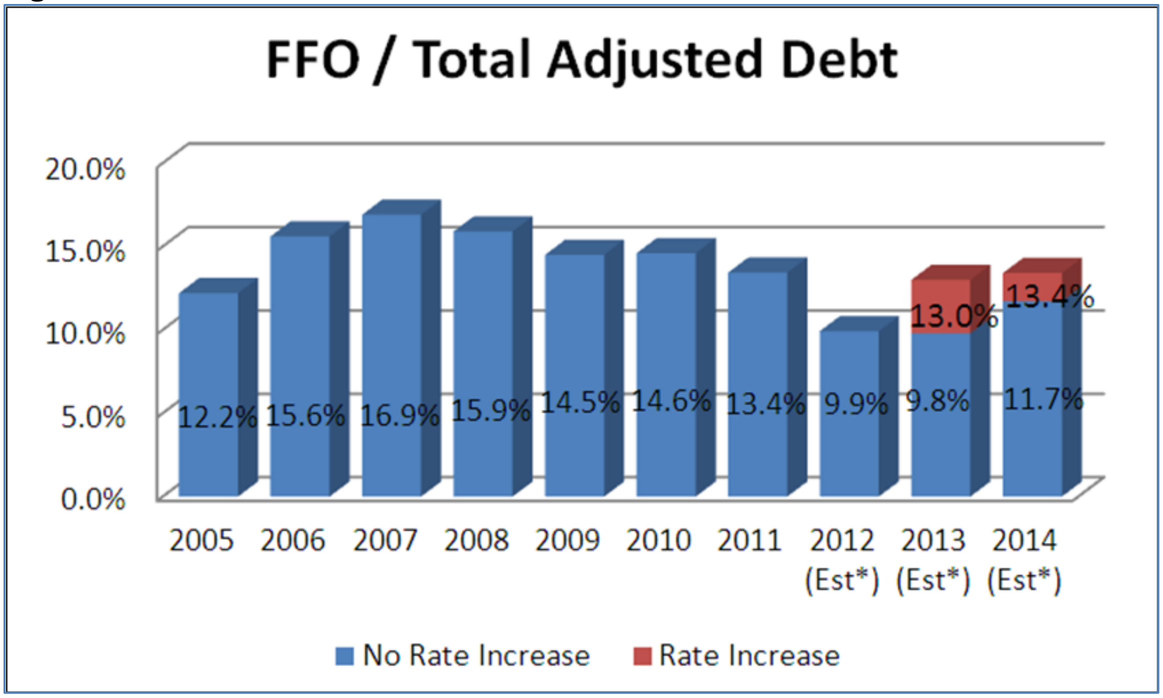
[1]Unless otherwise stated, the ratings apply to the company's unsecured debt. If a company has no such rating, its general corporate rating is shown.
[2]DBRS does not provide an unsecured debt or corporate credit rating for Altalink L.P. This is its Senior Secured Bond and Medium-Term Notes (Secured) rating.
[3]DBRS does not rate Maritime Electric Co. Ltd.

For a competitive credit rating, NS Power's financial profile – including its capital structure, the proportion of bonds and bank loans to investor equity – should be comparable to those of similar Canadian utilities. In fact, as noted in evidence presented by Kathleen McShane in Appendix H, the shareholder portion of NS Power's capital structure is currently lower than most of the utilities listed above.

Capital structure plays an important role in a company's overall credit standing. Credit rating agencies assess the long term solvency of a company by comparing its cash flow to its total debt. 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*. These measure a company's ability to repay the principal and interest on its debt with funds provided from day-to-day operations.

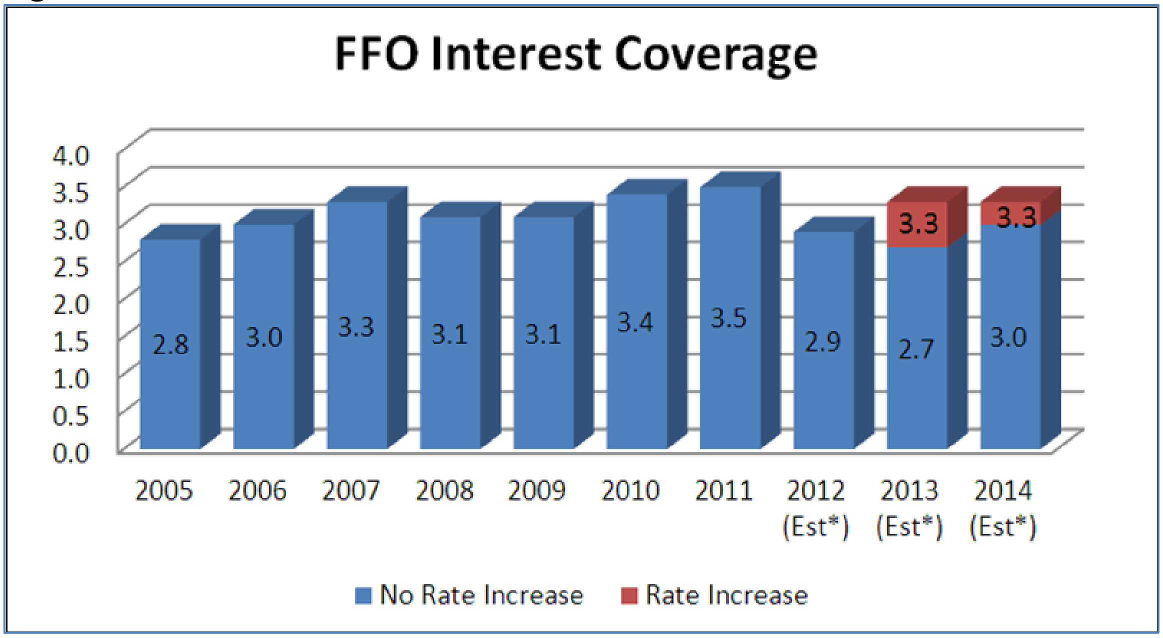
Without a rate increase, NS Power forecasts its 2013 and 2014 FFO/debt ratio and FFO/interest ratio will fall below the five year average. Please refer to Figure 9-2 and Figure 9-3. The 2012 value is trending lower due primarily to the Fixed Cost Recovery deferral.

Figure 9-3



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 2011 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 9-4



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 2011 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 enables NS Power to continue providing service at a reasonable cost to customers.

9.3 Return on Equity: Compensation for the Equity Investor

Because so many aspects of a regulated utility's operations are determined by the regulator, it doesn't have the same leeway as an unregulated company to influence its own profitability. In recognition of this, the regulator determines a fair rate of return, and factors that into its decisions about things like electricity prices. In NS Power's case, the *Return on Equity* depends on two factors: the amount of equity the Board recognizes for the purpose of setting rates, and the percentage return the Board allows on that equity.

NS Power's return on equity is the compensation provided to equity investors in return for using the investors' money to build power plants and other equipment with a long lifespan. It is similar to the interest paid on bonds and bank loans. When setting a fair rate of return for shareholders, the Board considers the riskiness of the investment compared to other alternatives.

In its Decision on the 2012 General Rate Application, the Board set rates based on a 9.2 percent rate of return and 37.5 percent common equity.[59] Unlike pure transmission and distribution utilities, NS Power is subject to operating risks in its generation business. Therefore, investors expect their fair return on investments in NS Power to be higher than the allowed returns for utilities without this risk.

Ms. McShane's expert evidence maintains that NS Power's proposed 9.2 percent ROE on a common equity ratio of 37.5 percent is below industry benchmarks.[60] While we do not question this evidence, we understand that an increase to ROE in the context of this Application would create additional burden for our customers at a time when electricity costs are rising significantly. As a result, NS Power asks the Board to maintain the current 9.2 percent ROE for rate setting purposes. This rate is consistent with the rate agreed to by customer representatives in the 2012 GRA Settlement Agreement, and approved by the Board in the 2012 Rate Decision. Given the recent and thorough review of ROE in the 2012 GRA, and given the evidence and expert opinion presented in this Application, we propose that rates be maintained at this level, within an acceptable range 9.1 to 9.5 percent, consistent with the 2012 GRA Decision.

9.4 Financing Outlook

NS Power is an asset intensive business. We own and operate many large facilities and systems. As a result, our financing costs are significant. To minimize these costs, it's

[59] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011, page 11, paragraph 16.
60 Appendix H, page 2, lines 32-33.

crucial that we have access to various kinds of financing – from commercial paper and bonds to preferred and common shares. That flexibility is fundamental to providing cost-effective service to customers.

9.4.1 Debt and Interest

NS 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 program. Commercial Paper 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. NS 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. Commercial Paper is the lowest cost form of borrowing for NS Power. Participating in this market provides NS Power with flexibility in managing its cash flow, typically rolling over amounts of $10-$25 million daily. Maintaining the current DBRS credit rating is imperative to have access to this efficient form of debt financing.

NS Power plans to participate extensively in the Commercial Paper market throughout 2013 and 2014. The 2013 forecast monthly average short-term rate is in the 2.4 to 3.5 percent range. The 2014 forecast monthly average short-term rate is in the 3.7 to 4.9 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, NS Power renewed its existing shelf-prospectus which has enabled it to issue up to $500 million in medium term notes[61] or preferred shares for the 25-month period subsequent to that date. This shelf-prospectus was subsequently increased to $800 million. To date, NS Power has issued $550 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. They 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.

NS Power has one long-term debt maturity of $300 million in 2013 and none for 2014.

9.4.2 Preferred Equity

NS 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.

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

Preferred dividends for 2013 and 2014 are consistent with the 2012 GRA Application. The annual preferred share dividend requirement is $8 million.

NS Power's 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, NS 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 NS 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.

9.4.3 Common Equity

Since 2005 Nova Scotia Power's common equity is 37.5 percent for rate-making purposes.[62] Since that time, NS Power has maintained actual regulated common equity of at least 37.5 percent.

In this Application, NS Power proposes to maintain common equity of 37.5 percent for the purposes of establishing electricity rates. NS Power proposes 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.

[62] NSPI 2005 General Rate Application, UARB Decision, NSUARB-NSPI-P-881, March 31, 2005.

10 COST OF SERVICE

10.1 Overview

A general rate application has two basic steps:

- First, the Board must determine the revenue requirement; how much it will cost to produce and deliver electricity to meet the demand of customers in the province, using the least-cost method, while complying with safety, reliability, and environmental standards, and allowing a fair rate of return on the money shareholders have invested to provide electricity to customers.

- Second, the Board must establish just and reasonable rates that recover the revenue requirement; the Board will determine how much of this total revenue requirement should come from each customer class, what mechanism should be used, and the time period for recovery. Traditionally, the revenue requirement is recovered through general rates over a single test year.

The next three sections 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 complicated, but well-established, having been examined and resolved through many previous rate applications.

To allocate costs, NS Power conducts what is called a Cost of Service Study (COSS). This is the process by which we calculate the portion of each cost that should be borne by each customer class. A detailed set of rules, approved by the Board in previous Orders, governs the way we carry out the calculations. The rules are called the Cost of Service Study Methodology.

This Application treats the two years that are covered, 2013 and 2014, separately, using the currently approved COSS Methodology. In its 2012 GRA Order, the Board directed NS Power to plan for a COSS hearing in the second quarter of 2013.[63] Consequently, NS Power is not proposing any changes to the COSS Methodology in this Application.

The costs we allocate in the COSS reflect the annual revenue requirements set forth in our financial tables.[64] However they do not include the fuel cost deferral, which will be addressed in separate proceedings for the annual Fuel Adjustment Mechanism.[65]

In the section below NS Power discusses a few changes it has made to the COSS within the confines of the current methodology, and also reports on anticipated completion of two amortization processes within the test year period.

For additional information, please refer to the following standardized filing documents:

Figure 10-1

Code	Description	Code	Description
SR-01	Cost of Service Study	OR-02	Miscellaneous Revenues
OP-10	Customers by Rate Class	OR-03	Unbilled Revenues
OP-11	Hydro Quebec Report	OR-05	Uncollectibles

10.2 Extra Large Industrial Two-Part Real-Time Pricing and Load Retention Tariffs

10.2.1 Treatment of the Deferred Fixed Cost Recovery

Over the years, NS Power incurred various fixed costs for the purpose of serving our two largest industrial customers, the paper mills at Port Hawkesbury and Liverpool. As with all large capital expenditures, those costs were amortized over many years. In light of the September 2011 closure of the Port Hawkesbury plant and the reduced, intermittent

[63] NSPI 2012 General Rate Application, UARB Order, NSUARB-NSPI-P-892, December 21, 2011.
[64] Refer to FOR-01.
[65] The revenue figures presented in financial tables FOR-01 and FOR-05 include revenues associated with the FAM Balance Adjustment (BA) rider.

operation of the Liverpool plant on a Load Retention tariff, those customers will contribute little, if at all, to fixed costs in 2012. Those fixed costs are to be recovered from other customers.

In calculating the 2013 and 2014 revenue requirements, we propose to amortize the Fixed Cost Recovery, projected to reach $44 million by the end of 2012, over the three years from 2013 to 2015. Consistent with the treatment of similar deferred costs, such as Demand Side Management discussed below, NS Power included parts of this deferral in both rate base and the cost of operations. The rate base component has been treated as a deferred charge. NS Power divided, or *functionalized*[66], it between generation and transmission. Then we further divided it between energy and demand, before allocating it among the customer classes. We have treated the annual amortization expense associated with this category in the same way, functionalizing and classifying it before allocating it among individual customer classes.

In deciding how to functionalize and classify these costs, we used the same approach followed in the 2012 General Rate Application's treatment of costs under the Extra Large Industrial Two-Part Real Time Pricing (ELI 2P-RTP) rate (under which the Port Hawkesbury and Liverpool mills were the only customers).

10.2.2 Direct Expenses Associated with the Below-the-line Rate of the Load Retention Tariff

Consistent with the COSS treatment of the Load Retention Tariff (LRT) costs in the 2011 Load Retention hearing, NS Power classified the avoided costs embedded in the LRT, except for those associated with the payment of the $4 per MWh fixed-cost adder, as fuel-related. This approach aligns with the treatment of the below-the-line Generation Replacement Load Following Rate class.

[66] Functionalization is the categorization of assets and other accounting costs by utility functions of generation, transmission, distribution and retail.

At the approved average avoided unit cost of 6.177 cents/kWh in 2013, and 6.386 cents/kWh in 2014, the fuel-related costs are $19.9 million and $20.6 million, respectively.[67] The non-fuel-related cost contributions of $1.3 million to be collected under the LRT in each of the two years have been prorated across-the-board to all non-fuel related generation and to the high-voltage portion of transmission costs.[68]

10.2.3 Suspension of the Extra Large Industrial Two-Part Real Time Pricing Rate Class

Neither of the two customers who previously took service under the Extra Large Industrial Two-Part Real Time Pricing Tariff continues to do so, and neither is expected to take service under this rate in the foreseeable future. As a result, we have removed the Extra Large Industrial Two-Part Real Time Pricing tariff from our tariff book. No costs were allocated to this class in the COSS. However, we have retained the associated label references and spreadsheet formulas in the event an eligible customer requests service under this tariff in the future.

10.3 Stranded Costs Associated with Early Retired Streetlight Fixtures

Provincial regulation will require the replacement of non-LED streetlight fixtures, which means that we will be retiring most of this equipment before the end of its useful life. As explained in Appendix I of this Evidence, NS Power proposes to treat the non-depreciated net book value of these streetlight fixtures as a stranded cost that constitutes a regulatory asset. We propose to defer the amortization of this asset until the Board approves the recovery of this cost through the implementation of appropriate LED streetlight conversion charges. This will happen in concert with the Capital Work Order Application for the LED streetlight conversion program. We propose to recover the capital carrying costs associated with this regulatory asset from the full service LED streetlight customers.

[67] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011, page 75 paragraph 210.
[68] $4/MWh * 3,220,080 MWh = $1.3 million.

10.4 Deferred Demand Side Management and Vegetation Management Costs

Amortization of NS Power's Demand Side Management expenditures, incurred in 2008 and 2009, was approved for recovery in the 2009 GRA, with a 6-year amortization schedule.[69] We continue to include it in the Cost of Service Study as a separate line item. For rate base classification purposes, we treat this item in the same way as other deferred charges,[70] and we allocate the amortized costs in the same way as fixed generation costs, consistent with the 2009 General Rate Application. They will be fully recovered by the end of 2014.

Amortization of the 2008 Vegetation Management costs, recovered over two years beginning 2012, will end at the end of 2013. This $1.0 million amortization expense has been included in the Cost of Service Study as an operations expense under transmission and distribution.

Further details can be found regarding proposed changes to the Large Industrial Tariff and Load Retention Tariff in Appendices J and K, the Unmetered Class Ratemaking Report in Appendix I, and in the Cost of Service Study, which is included in this Application as SR-01. Exhibit 10 and 10A of SR-01 Attachment1 presents revenue-to-cost ratios for each customer class under current and proposed rates. Appendix O provides a listing of all changes made by NS Power since the time the COSS was submitted to the Board in the 2012 GRA Compliance Filing.

[69] NSPI 2009 General Rate Application, UARB Decision, NSUARB-NSPI-P-888, November 5, 2008, page 39, paragraph 107.

[70] DSM amortization costs are grouped within the regulatory amortization item in the financial table found in FOR-01.

11 REVENUE FORECAST AND PROPOSED RATES

11.1 Overview

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

The Fuel Adjustment Mechanism provides an annual process by which rates are adjusted to reflect the latest information about the cost of fuel. It was put in place to manage the recent volatility in the price of fuel used to generate electricity. The process includes two sets of adjustments, known as the Actual Adjustment and the Balance Adjustment, that serve to true up rates once the actual amounts paid for fuel in prior years are known.

The Fuel Adjustment Mechanism Actual and Balance Adjustments for 2013 and 2014 are not part of the rate analysis in this Application. This conforms to the treatment of such costs in the Cost of Service Study Methodology. However, in order to provide a comprehensive view of proposed changes in the cost of electricity to customers in 2013 and 2014, this Application provides a preliminary look at the combined impact on rates of the proposed changes to the base cost of fuel and the preliminary forecasts of the amounts that can be expected under the Fuel Adjustment Mechanism (Figure 11-5 and Figure 11-6).

For additional information, please refer to the following standardized filing documents:

Figure 11-1

Code	Description	Code	Description
OR-01	Proof of Revenues	PR-02	Proposed Miscellaneous Charges
PR-01	Proposed Tariffs	PR-03	Proposed Regulation Changes

11.2 Proposed Tariff Changes Other than those Arising from Revenue Requirement

Aside from rate changes driven by an increase in revenue requirement, NS Power proposes the following:

- modifiying the wording of the Large Industrial Interruptible Rider and (LIIR) and the Load Retention Tariff (LRT) Pricing Mechanism to reflect the obligations of customers who pay substantially lower rates in return for allowing NS Power to interrupt their service on short notice – These changes conform to the way NS Power has treated customers under this program to date, and reflect comments the Board made in a recent Decision.[71]

- updating the pricing mechanism of the Open Access Transmission Tariff (OATT) to reflect forecast costs in 2013 and 2014 – This tariff allows municipal distribution utilities to purchase power from other suppliers, and use NS Power's transmission system to deliver it to their systems.

- introducing an Embedded Cost Recovery Mechanism by which municipal power utilities that use the Open Access Transmission Tariff will protect other customers from having to pay for generation-related fixed costs incurred to serve the municipal power utilities

- part two of an adjustment to the method used to calculate unmetered rates, so as to better align those rates with costs, as agreed in the 2012 General Rate Application Settlement

Details of the proposed update to the pricing section of the Open Access Transmission Tariff, the proposed Embedded Cost Obligation Mechanism, and the proposed adjustment

[71] Appeal by Ligni Bel Ltd. from a Decision of the Dispute Resolution Officer which upheld an Interruption Call Penalty by Nova Scotia Power Incorporated, UARB Decision, NSUARB-NSPI-P-401.13, March 22, 2012.

to unmetered rates are discussed in separate appendices to this Application, as indicated in the summaries below.

11.2.1 Modification to Supply Interruption Provisions

The current wording of the Availability provision of the Large Industrial Interruptible Rider requires customers in this rate category to reduce their interruptible load within 10 minutes of a 'request' from NS Power, by the amount we stipulate. Failure to comply with such a request, in whole or in part, will result in a penalty charge calculated based on the customer's performance after the interruption request was 'delivered' by telephone call.

In a recent decision[72], the Board considered the case of a customer, who alleged that the phone at their premises did not ring. The Board found that NS Power initiated and sent a a call to the customer's dedicated phone, but that the phone did not ring at the customer's premises. In communications with and presentation made to this particular customer, and other interruptible customers, NS Power communicated that it is the customer's responsibility to maintain their phone in proper working order, that they must answer all calls, and that failure to answer a call will not excuse a customer from penalty under the LIIR. The Board considered this evidence however given this explicit wording was not contained within the wording of the tariff itself, the Board stated, "To support NSPI's contention, the tariff must be explicit."[73]

The Board found that the wording of the tariff required a request to be made. The Board concluded that "[…] a "request" is made by or from someone to someone else."[74] As such, to make a request under the current wording of the tariff, the communication must be received; that is, the phone must be answered.

[72] Appeal by Ligni Bel Ltd. from a Decision of the Dispute Resolution Officer which upheld an Interruption Call Penalty by Nova Scotia Power Incorporated, UARB Decision ("Ligni Bel Decision"), NSUARB-NSPI-P-401.13, March 22, 2012.
[73] Ligni Bel Decision at paragraph 86.
[74] Ligni Bel Deicsion at paragraph 83.

NS Power has proposed amendments to the LIIR that reflect the Board's comments in the Ligni Bel Decision. The new wording removes all references to the words 'request' and 'delivered', and replaces them with wording that requires NS Power to initiate and send to a customer's dedicated line the notice of an interruption requirement. The new proposed rider also confirms the customer's obligation to maintain a dedicated telephone number and a dedicated telephone system in working order at all times. It confirms that the customer is responsible to comply once NS Power has properly initiated and sent a notice to the customer, even if the customer does not answer the phone. We propose these changes to address the Board's observation that the current wording of the tariff is not consistent with NS Power's communications to customers about their obligations.

Since the proposed changes conform to NS Power's longstanding communications with all interruptible customers, they should not represent a change for those customers in terms of their understanding of their obligations under this rate. The changes are made to ensure that the tariff aligns explicitly with NS Power's communications to customers about their obligations under the program. These changes will make the tariff more effective. They will benefit all customers whose rates support the discount received by interruptible customers, instead of paying for fast-acting generators to meet the North American Electric Reliability Corporation's reserve capacity requirements. Please refer to Appendix J for a copy of the proposed LIIR.

The Extra Large Industrial Two-Part Real Time Pricing Tariff and the Load Retention Tariff Pricing Mechanism also both have supply interruption components. Since NS Power proposes to eliminate the Extra Large Industrial Two-Part Real Time Pricing tariff it does not need to be changed at this time. We are proposing amendments to the Bowater Load Retention Tariff Pricing Mechanism consistent with those proposed for the LIIR. Appendix K sets out the proposed revisions to the Supply Interruption provision of the Load Retention Tariff Pricing Mechanism. In addition, we have made a small amendment to the Load Retntion Tariff Pricing Mechanism to reflect the fact that the customer on this tariff is billed weekly, yet the Threshold Penalty provisisions associated with supply interruption customers were originally approved on the assumption that the customers' "billing period" is one month. The Threshold Penalty is designed to assess a penalty that is based on the cost of the appropriate firm billing effective at that time for the customers' consumption in a month long billing period. To ensure the Threshold Penalty has the effect that was intended, we have proposed amended wording to change the words 'billing period' to 'month'.

11.2.2 Update to Charges under the Open Access Transmission Tariff

The Open Access Transmission Tariff (OATT) sets out the terms and rates under which NS Power's transmission system can be used by transmission customers for delivery of power produced by third parties. Charges under this tariff have not been updated since the Board approved them in May 2005.[75] In this Application, NS Power is not proposing any changes in the terms and conditions of this tariff, or to the method by which it sets rates. We have updated the current charges to reflect changes in revenue requirement and system use.

Please refer to Appendix L for further information on the updated OATT pricing mechanism.

11.2.3 Embedded Costs Applicable to Open Access Transmission Customers

NS Power builds generation capacity based on expected load and peak use. If a Municipal Electric Utility takes advantage of the Open Access Transmission Tariff to purchase power elsewhere, then NS Power will be left with unrecovered costs we expected to recoup by selling power to that customer. Other jurisdictions with Open Access Tariffs provide a mechanism for the utility to recover those costs from a departing customer, while currently, Nova Scotia does not.

[75] Open Access Transmission Tariff Proceeding, UARB Order, NSUARB-NSPI-P-880, May 31, 2005.

As discussed earlier in this Application, the issue of recovery of fixed system costs from customers as a result of recent changes in the province's pulp and paper industry is a challenging issue for all parties involved. In Nova Scotia, wholesale customers are entitled to supply their electricity needs from other sources. In the absence of a mechanism similar to that used in other jurisdictions, the departure of the utility's wholesale customers (Municipal Electric Utilities) from the system, would shift additional fixed costs to other customers. NS Power proposes changes in this situation to avoid this outcome for other customers.

NS Power seeks amendments to the ratemaking framework of the OATT to provide an Embedded Cost Recovery Mechanism that will protect the interests of other customers when Municipal Electric Utilities (MEUs) opt for third-party electricity supply.

When an industrial customer leaves the system due to bankruptcy, or is placed on the Load Retention Rate in response to financial hardship, there is no opportunity to protect other customers from having to make up the shortfall because the customer lacks the ability to pay. Without a cost recovery mechanism, the OATT gives eligible customers an option to escape their cost responsibilities for the investments incurred to serve them by NS Power.

The purpose of this Application is to ensure that the OATT functions as it was intended, and that other customers are not unfairly burdened.

Specifically, this proposal is about protecting our customers from further cost transfers. In the absence of a recovery mechanism, other customers will become responsible for any embedded system costs associated with the departing customers, as determined by the Cost of Service Study. Over the years, infrastructure has been put in place – in good faith – to serve MEU load, creating embedded costs. A decision to switch to a third party supplier should be made neutral to fixed costs responsibilities. To allow otherwise, would mean the departing customer escapes its cost responsibilities at the expense of all other customers.

Background to this proposal is provided in Appendix L.

11.2.4 Unmetered Class

In 2011, the province passed the Energy Savings Roadway Lighting (2011) Act,[76] which authorizes regulations requiring roadway lighting to meet designated efficiency standards. On April 25, 2012, the provincial government announced[77] draft regulations which are currently undergoing public consultation. The draft regulations would require large-scale deployment of light emitting diode (LED) streetlights to be completed by June 19, 2019.[78] The deployment will replace the mercury vapour, low pressure sodium, and high pressure sodium streetlights. This will significantly increase the value of streetlights in place, while reducing the amount of electricity used to power them. This requires changes to the long-standing streetlight ratemaking methodology.

In our 2012 General Rate Application, NS Power proposed to change the method of setting rates for unmetered services.[79] In the Settlement Agreement approved by the Board, stakeholders accepted the proposed changes with two exceptions: the modifications called for phasing in the alignment of rates and costs in two stages, and deferred determination of the value of the non-LED stranded assets, as well as the method of recovering them until an LED capital work order is submitted.[80]

In this Application, NS Power proposes to complete the second phase of aligning non-metered rates with costs, and to do so in a manner consistent with the approved rate design changes in the Board's 2012 GRA Decision. As agreed in the 2012 GRA Settlement Agreement, we will defer the determination of the value and method of

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[76] *Energy Savings Roadway Lighting* (2011) Act, R.S.N.S. c. 6, 2011.
[77] Press Release, Government of Nova Scotia, April 25, 2012, http://www.gov.ns.ca/news/details.asp?id=20120425003.
[78] Draft Energy Efficient Appliance Regulations: http://www.gov.ns.ca/energy/publications/Draft-LED-Regulations-2012-tracked-changes_2.pdf
[79] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011.
[80] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011, paragraph 21.

recovering non-LED stranded assets until the regulatory proceeding on the LED Capital Work Order submission. At that time, NS Power will also propose the updated LED fixture capital rates. The 2013 and 2014 Unmetered Services Cost of Service and Pricing Study Review in Appendix I offers further discussion of this issue.

11.3 Rate-setting Process Overview

In the context of revenue inputs used in a GRA rate-setting process, NS Power's rates fall into four categories:

1. Above-the-line electric service rates, which are changed through the revenue requirement proceedings of a General Rate Application, or in the absence of a GRA, through the FAM adjustment process, which allows re-setting of the Base Cost of Fuel in above-the-line rates every second year. Above-the-line rates are developed using the Board-approved cost of service and rate design methodology. NS Power bills most customers under above-the-line rates.

2. Below-the-line electric service rates, which are, with exceptions, reset annually based on pre-approved methodologies. The exceptions are the Mersey Additional Energy and Load Retention Tariff rates. The Bowater paper mill can choose to have Mersey Additional Energy billed under the above-the-line rates as a Large Industrial Rider, or at the below-the-line rate known as Generation Replacement and Load Following rate.

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

4. Capital costs of LED streetlights and associated stranded capital costs of early retired non-LED fixtures.

Assuming Bowater opts for a Generation Replacement and Load Following rate, the rate-setting process for each year consists of two steps:

- Determining the total revenue shortfall from the year's revenue requirement, assuming no rates were to change except for those below-the-line rates that are reset annually.[81]

- Calculating the remaining revenue increases needed from all above-the-line classes, and from the below-the-line categories of LED capital and Miscellaneous Services.

11.4 Revenue Allocation Process and Results

11.4.1 2013 Overview

The total revenue forecast for 2013 – based on current rates for all above-the-line classes, miscellaneous, LED capital, and projected below-the-line rates, including forecast export revenues – is $1,192.6 million. The 2013 revenue requirement is $1,323.0 million, leaving a revenue shortfall of $130.4 million.[82] Assuming Bowater opts for the Generation Replacement and Load Following rate in 2013, and assuming a forecast $2 million revenue requirement for below-the-line category of LED Fixture Capital, the shortfall applicable to above-the-line and Miscellaneous Service rates is $130 million.

11.4.2 2014 Overview

The total revenue forecast for 2014 – assuming above-the-line electric, miscellaneous and LED fixture-capital services are priced at the proposed rates for 2013, and below-the-line

[81] For the purposes of determining the revenue shortfall in the 2014 test year, the revenues 'at current rates' were generated using rates proposed for the 2013 test year.
[82] The figures of $1,192.6 and $1323 million were calculated by subtracting the forecast FAM BA revenue of $29.2 million for 2013 from the total revenue of $1,222.8 million (present rates) and $1,352.2 million (proposed rates) displayed in the financial table found in FOR-01.

electric services are priced using projected rates for 2014, and including forecast export revenues – is $1,320.4 million. The 2014 revenue requirement is $1,387.9 million, leaving a revenue shortfall of $67.5 million. Assuming Bowater opts for the Generation Replacement and Load Following rate in 2014, and assuming a forecast $4.3 million revenue requirement for below-the-line category of LED Fixture Capital, the shortfall applicable to above-the-line and Miscellaneous Service rates is $67.4 million.

The pricing assumptions behind the LED fixture Capital-related services and below-the-line electric service classes form an important intermediate step in the determination of the revenue shortfalls from above-the-line classes and Miscellaneous Services.

11.4.3 Revenue Forecast of LED Fixture Capital-related Services and Below-the-Line Electric Service Rate Classes

NS Power forecasts the LED fixture-related revenue requirements to be $2.0 million in 2013 and $4.3 million in 2014. The Street/Crosswalk Lighting Study in Appendix I, Attachment 1 contains the details behind these calculations.

The below-the-line electric service class revenues reflect customer loads under the Generation Replacement and Load Following, Mersey Additional Energy, and Load Retention Tariff rates, together with the Mersey Basic Contract. NS Power forecasts total annual sales to this category to be 708.8 GWh in both 2013 and 2014, or approximately 7 percent of total in-province sales in those years. The forecast revenue from below-the-line sales is $42.5 million in 2013, and $43.0 million in 2014, or 3 percent of total revenues. The details are discussed below.

11.4.3.1 Generation Replacement and Load Following Rate

The Generation Replacement and Load Following (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 2013 and 2014, NS Power forecasts annual energy sales priced under this rate at 197.7 GWh. The sales for both years consist of 18.8 GWh billed directly under the GRLF class and 178.9 GWh billed under the Mersey Additional Energy Class, which permits the customer to choose between the Load Following and the Large Industrial Interruptible rates. Generation Replacement and Load Following revenue is determined by applying the relevant rate components to the Load Following and Generation Replacement portions of the kWh sales projected for each customer. The Load Following rates are based on the forecast average incremental cost of serving 25 MW of load in each year, plus a $5/MWh adder. The Generation Replacement 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 these rates based on the assumption that no exports are being served. Projected annual revenue under the Generation Replacement and Load Following rate is $1.1 million in 2013 and 2014. Projected annual revenue under the Mersey Additional Energy rate is $10.3 million in 2013, and $10.2 million in 2014.

The current forecast for the Load Following rate is 5.747 cents/kWh for 2013, and 5.724 cents/kWh for 2014. The annual updates to the Load Following Rate will be proposed by NS Power using a separate Annually Adjusted Rate process in the fall of 2012 and 2013.

11.4.3.2 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 of service, 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 amounts forecast for 2013 and 2014 are $9.9 million and $9.8 million, respectively.

The portion of energy sold to Bowater and covered under the Mersey Agreement is known as *Mersey Additional Energy*. Bowater is entitled, in advance of each rate year, to select either Generation Replacement and Load Following, or Large Industrial

Interruptible Rider pricing for this load. For both 2013 and 2014, NS Power has assumed that this load will be priced at the Load Following rate.

11.4.3.3 Load Retention Rate

The Board's Decision on the Load Retention Rate hearing[83] approved an escalated 3-year Load Retention Rate as follows.

Figure 11-2

Year (January 1 to December 31)	Variable Incremental Rate (cents per kWh)	Contribution to Fixed costs (cents per kWh)	Energy charge (cents per kWh)
2012	5.624	0.400	6.024
2013	6.177	0.400	6.577
2014	6.386	0.400	6.786

Since January 1, 2012, one customer, Bowater, has placed its former Extra Large Industrial Two-Part Real Time Pricing load under this rate. NS Power forecasts an annual load of 322.1 GWh in both 2013 and 2014, and revenues of $21.2 million in 2013, and $21.9 million in 2014.

11.4.4 Revenue Responsibilities Allocated to Above-the-Line Classes and Miscellaneous Revenues

The following tables illustrate the process used by NS Power to allocate revenue responsibilities among above-the-line classes and miscellaneous services for 2013 and 2014. NS Power has followed a process intended to fairly and equitably recover costs from all classes. Appendix N provides the details behind this allocation.

11.4.4.1 2013 Results

Figure 11-3 presents revenue-to-cost ratios for above-the-line classes associated with proposed revenue increases. Revenue-to-cost ratios for all rate classes fall within the

[83] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011.

prescribed 95-105 percent band. All classes, other than unmetered, see a uniform increase of 11.5 percent. The increase to the unmetered class revenue of 10.3 percent is determined by setting the revenue at the cost of service.

Figure 11-3

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.0%**	**11.5%**	**$656.6**
Commercial			
Small General	104.6%	11.5%	$35.1
General Demand	103.5%	11.5%	$307.8
Large General	98.2%	11.5%	$42.2
Total Commercial	**103.0%**	**11.5%**	**$385.0**
Industrial			
Small Industrial	102.5%	11.5%	$31.7
Medium Industrial	98.4%	11.5%	$53.5
Large Industrial	95.5%	11.5%	$82.3
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**97.7%**	**11.5%**	**$167.6**
Other			
Municipal	97.4%	11.5%	$20.4
Unmetered	100.0%	10.3%	$24.6
Total Other	**98.8%**	**10.8%**	**$45.0**
Total Above-the-line classes	**100.0%**	**11.5%**	**$1,254.2**
BTL (Electric Services)		**0.0%**	**$42.5**
Exports		**0.0%**	**$1.8**
LED SL Capital-related Costs		**N/A**	**$2.0**
Miscellaneous		**2.8%**	**$22.6**
Total Revenue		**10.9%**	**$1,323.0**
Revenue Requirement			**$1,323.0**
Revenue Shortfall/Surplus			**$0.0**

11.4.4.2 2014 Results

Figure 11-4 presents revenue to cost ratios for above-the-line classes associated with proposed revenue increases. Revenue-to-costs ratios for all rate classes fall within the prescribed 95-105 percent band. All classes, other than unmetered and large industrial, see a uniform increase of 5.4 percent. The increase to the unmetered class revenue of 3.9 percent is determined by setting this revenue at the cost of service. The increase to the Large Industrial class of 5.4 percent reflects an extra adjustment necessary to bring its revenue within the 95 - 105 percent band.

Figure 11-4

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.4%**	**5.4%**	**$689.8**
Commercial			
Small General	104.4%	5.4%	$36.7
General Demand	102.8%	5.4%	$322.0
Large General	98.7%	5.4%	$43.7
Total Commercial	**102.5%**	**5.4%**	**$402.3**
Industrial			
Small Industrial	102.0%	5.4%	$33.5
Medium Industrial	97.3%	5.4%	$57.3
Large Industrial	95.0%	5.4%	$86.8
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**97.0%**	**5.4%**	**$177.6**
Other			
Municipal	98.0%	5.4%	$21.5
Unmetered	100.0%	3.9%	$24.0
Total Other	**99.0%**	**4.6%**	**$45.5**
Total Above-the-line classes	**100.0%**	**5.4%**	**$1,315.2**
BTL (Electric Services)		**0.0%**	**$43.0**
Exports		**0.0%**	**$1.9**
LED SL Capital-related Costs		**N/A**	**$4.3**
Miscellaneous		**1.4%**	**$23.5**
Total Revenue		**5.1%**	**$1,387.9**
Revenue Requirement			**$1,387.9**
Revenue Shortfall/Surplus			**$0.0**

11.5 Combined 2013 Revenue Increase Effect for All Known Rate Changes

At the time of preparing this Application, NS Power did not make a projection of the 2013 FAM Actual Adjustment (AA) effect. However, we did provide an estimate of the 2013 FAM Balance Adjustment (BA) amount. The full 2013 FAM rider amounts will be approved for recovery by the Board in a separate FAM proceeding to be held in the fall of 2012. The combined effect of the proposed rate changes in this Application and the FAM deferral amount, compared to 2013 revenues priced at present rates, and adjusted for the 2012 FAM AA and BA riders, are presented in the following table.

Figure 11-5

Combined Revenue Effect of all Rate Changes in 2013
(as Measured Against 2013 Revenues at Present Rates Adjusted for FAM Effects from 2012)

Rate Classes	2013 GRA	FAM 2013 AA	FAM 2013 BA	Combined effect in 2013
ATL				
Residential	**11.0%**	**-2.5%**	**-0.4%**	**8.0%**
Small General	11.0%	-2.5%	-0.4%	8.1%
General Demand	10.8%	-3.1%	-0.5%	7.1%
Large General	10.7%	-3.3%	-0.3%	7.2%
Total Commercial	**10.8%**	**-3.1%**	**-0.5%**	**7.2%**
Small Industrial	10.9%	-2.8%	-0.2%	7.9%
Medium Industrial	10.8%	-3.1%	-0.2%	7.5%
Large Industrial	10.7%	-3.6%	-0.1%	6.9%
ELI 2PT - RTP	N/A	N/A	N/A	N/A
Total Industrial	**10.7%**	**-3.3%**	**-0.2%**	**7.3%**
Municipal	10.7%	-3.4%	-1.0%	6.4%
Unmetered	9.9%	-1.6%	-0.1%	8.3%
Total Other	**10.3%**	**-2.4%**	**-0.5%**	**7.4%**
Total ATL Classes	**10.9%**	**-2.8%**	**-0.4%**	**7.7%**
BTL				
GRLF	0.0%	0.0%	0.0%	0.0%
Mersey Additional Energy	0.0%	0.0%	-1.2%	-1.2%
LRT	0.0%	-3.8%	0.5%	-3.3%
Bowater Mersey	0.0%	0.0%	0.0%	0.0%
Total BTL Classes	**0.0%**	**-2.0%**	**0.0%**	**-2.0%**
LED SL Capital Costs	**25.4%**	**0.0%**	**0.0%**	**25.4%**
In Province Total	**10.5%**	**-2.8%**	**-0.4%**	**7.3%**
Export	0.0%	0.0%	0.0%	0.0%
Total Electric Sales	**10.5%**	**-2.8%**	**-0.4%**	**7.3%**
Misc Revenue	**2.8%**	**0.0%**	**0.0%**	**2.8%**
Grand Total	**10.3%**	**-2.7%**	**-0.4%**	**7.2%**

Appendix M provides detailed calculations behind the percentage increases.

11.6 Combined 2014 Revenue Increase Effect Reflective of all known Rate Changes

At this point in time, NS Power assumes the FAM AA and BA amounts for 2014 at zero. The BA decreased by $20 million in 2014, compared to 2013, reflecting the conclusion of the 2010 FAM deferral. Actual rider amounts for 2014 will be approved for recovery by the Board in a separate FAM proceeding to be held in the fall of 2013.

Please note that Figure 11-5 (2013) and Figures 11-4 and Figure 11-6 (2014) do not show the same percentage increases as they are not compared to the same base revenue rates.

1 **Figure 11-6**

Rate Classes	2014 GRA	FAM 2014 AA	FAM 2014 BA	Combined effect in 2014
Combined Revenue Effect of all Rate Changes in 2014 (as Measured Against 2014 Revenues at Present Rates Adjusted for FAM Effects from 2013)				
ATL				
Residential	**5.3%**	**0.0%**	**-1.7%**	**3.6%**
Small General	5.3%	0.0%	-1.9%	3.4%
General Demand	5.3%	0.0%	-2.4%	2.8%
Large General	5.2%	0.0%	-3.1%	2.1%
Total Commercial	**5.3%**	**0.0%**	**-2.5%**	**2.8%**
Small Industrial	5.3%	0.0%	-2.5%	2.7%
Medium Industrial	5.2%	0.0%	-2.8%	2.4%
Large Industrial	5.2%	0.0%	-3.6%	1.7%
ELI 2PT - RTP	N/A	N/A	N/A	N/A
Total Industrial	**5.2%**	**0.0%**	**-3.1%**	**2.1%**
Municipal	5.3%	0.0%	-2.5%	2.7%
Unmetered	3.9%	0.0%	-1.7%	2.1%
Total Other	**4.5%**	**0.0%**	**-2.1%**	**2.4%**
Total ATL Classes	**5.3%**	**0.0%**	**-2.2%**	**3.1%**
BTL				
GRLF	0.0%	0.0%	0.0%	0.0%
Mersey Additional Energy	0.0%	0.0%	-2.8%	-2.8%
LRT	0.0%	0.0%	-5.7%	-5.7%
Bowater Mersey	0.0%	0.0%	0.0%	0.0%
Total BTL Classes	**0.0%**	**0.0%**	**-3.6%**	**-3.6%**
LED SL Capital Costs	**1.9%**	**N/A**	**N/A**	**1.9%**
In Province Total	**5.1%**	**0.0%**	**-2.2%**	**2.9%**
Export	0.0%	0.0%	0.0%	0.0%
Total Electric Sales	**5.1%**	**0.0%**	**-2.2%**	**2.9%**
Misc Revenue	**1.4%**	**0.0%**	**0.0%**	**1.4%**
Grand Total	**5.0%**	**0.0%**	**-2.2%**	**2.8%**

2

11.7 Proposed Rates

Electric rates typically comprise:

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

In an ideal rate design, demand charges should recover the demand-related costs of providing electric service, energy charges should recover the energy-related costs, and the customer charge should recover costs of customer-related activity. Due to historical revisions to the rates at various regulatory proceedings, NS Power's rate components do not precisely follow this model.

In keeping with the Board's 2003 Decision on Generic Rate Design,[84] NS Power does not propose to increase customer charges in this Application. We also do not propose to change the interruptible and transformer ownership credits. We propose to increase only demand and energy charges.

As a result, these components of each rate will undergo higher percentage increases than the rate class as a whole. Percentage increases on individual customers' bills will vary, but will not exceed the percentage increases to the demand and energy charge components. The revenue responsibilities attributed to each rate class, shown in Figure 11-3 and Figure 11-4, form an input into the calculation of the proposed rate components shown in Figure 11-7 and Figure 11-8, and their changes against current values.[85] The "Proof of Revenue" section included in the standard filing document OR-01 of this Application presents the detailed calculations for each rate component.

[84] NSPI 2003 Generic Rate Design, UARB Decision, NSUARB-NSPI-P-878, August 1, 2003, paragraph 128.
[85] The current and proposed energy charges reflect base costs only. They do not include FAM riders.

Figure 11-7

2013 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	12.638	14.252	12.8%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.820	18.820	0.0%
December, January & Feb: energy charge					
	on-peak	¢/kWh	16.435	18.595	13.1%
	shoulder	¢/kWh	12.638	14.252	12.8%
	off-peak	¢/kWh	6.468	7.318	13.1%
Other months: energy charge					
	on-peak	¢/kWh	12.638	14.252	12.8%
	off-peak	¢/kWh	6.468	7.318	13.1%
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	13.370	15.111	13.0%
Energy Charge, block 2		¢/kWh	11.762	13.294	13.0%
General Rate					
Demand Charge		$/kW	9.276	10.344	11.5%
Energy Charge, block 1 (first 200kWh * demand)		¢/kWh	9.904	11.045	11.5%
Energy Charge, block 2		¢/kWh	7.006	7.814	11.5%
Transformer Ownership Credit		$/kVA	(0.320)	(0.320)	0.0%
Large General Rate					
Demand Charge (Ratcheted)		$/kVA	11.702	13.046	11.5%
Energy Charge		¢/kWh	7.040	7.849	11.5%
Transformer Ownership Credit		$/kVA	(0.320)	(0.320)	0.0%

1 **Figure 11-7 Continued**

2013 PROPOSED INCREASES BY RATE COMPONENT

INDUSTRIAL TARIFFS

Small Industrial Rate	units	Current Rate	Proposed Rate	% change
Demand Charge	$/kVA	6.854	7.644	11.5%
Energy Charge, block 1 (first 200 kWhs * demand)	¢/kWh	8.965	9.998	11.5%
Energy Charge, block 2	¢/kWh	6.848	7.637	11.5%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Medium Industrial Rate				
Demand Charge	$/kVA	11.032	12.304	11.5%
Energy Charge	¢/kWh	6.390	7.127	11.5%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	10.469	11.587	10.7%
Energy Charge to firm Customers	¢/kWh	6.369	7.048	10.7%
Energy Charge to interruptible customers		6.369	7.048	10.7%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Interruptible Credit	$/kVA	(3.430)	(3.430)	0.0%

MUNICIPAL TARIFFS

Municipal Rate	units	Current Rate	Proposed Rate	% change
Demand Charge (Ratcheted)	$/kVA	10.910	12.163	11.5%
Energy Charge	¢/kWh	6.609	7.368	11.5%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

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Figure 11-8

2014 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	14.252	15.096	5.9%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.820	18.820	0.0%
December, January & Feb: energy charge					
	on-peak	¢/kWh	18.595	19.741	6.2%
	shoulder	¢/kWh	14.252	15.096	5.9%
	off-peak	¢/kWh	7.318	7.769	6.2%
Other months: energy charge					
	on-peak	¢/kWh	14.252	15.096	5.9%
	off-peak	¢/kWh	7.318	7.769	6.2%

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	15.111	16.023	6.0%
Energy Charge, block 2	¢/kWh	13.294	14.096	6.0%
General Rate				
Demand Charge	$/kW	10.344	10.903	5.4%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	11.045	11.641	5.4%
Energy Charge, block 2	¢/kWh	7.814	8.236	5.4%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Large General Rate				
Demand Charge (Ratcheted)	$/kVA	13.046	13.749	5.4%
Energy Charge	¢/kWh	7.849	8.272	5.4%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

Figure 11-8 Continued

2014 PROPOSED INCREASES BY RATE COMPONENT				
INDUSTRIAL TARIFFS				
Small Industrial Rate	**units**	**Current Rate**	**Proposed Rate**	**% change**
Demand Charge	$/kVA	7.644	8.057	5.4%
Energy Charge, block 1 (first 200 kWhs * demand)	¢/kWh	9.998	10.538	5.4%
Energy Charge, block 2	¢/kWh	7.637	8.049	5.4%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Medium Industrial Rate				
Demand Charge	$/kVA	12.304	12.968	5.4%
Energy Charge	¢/kWh	7.127	7.511	5.4%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	11.587	12.174	5.1%
Energy Charge to firm Customers	¢/kWh	7.048	7.405	5.1%
Energy Charge to interruptible customers		7.048	7.405	5.1%
Equalization adj to firm customers	¢/kWh	-	-	NA
Equalization adj to interruptible customers	¢/kWh	-	-	NA
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Interruptible Credit	$/kVA	(3.430)	(3.430)	0.0%
MUNICIPAL TARIFFS				
Municipal Rate	**units**	**Current Rate**	**Proposed Rate**	**% change**
Demand Charge (Ratcheted)	$/kVA	12.163	12.818	5.4%
Energy Charge	¢/kWh	7.368	7.765	5.4%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

11.8 Miscellaneous Charges

NS Power provides a variety of services to customers. Section 7 of the Board approved Regulations, entitled, Schedule of Charges, sets out the charges for these services.[86] NS Power reviews these charges from time to time in light of changes in service delivery, cost structure, and technological advances.

[86] NSPI Tariffs & Regulations (UARB Approved), January 1, 2012, http://www.nspower.ca/en/home/aboutnspi/ratesandregulations/nsuarbsapprovedregulations.aspx

NS Power seeks to apply the average general rate increase for above-the-line rates to Miscellaneous Charges. The Board approved this approach in the 2006 Rate Case.[87]

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. PR-02 and PR-03 describes a number of proposed changes to charges associated with Regulation 7.1-7.3.

Miscellaneous revenue is forecast to increase $0.6 million in 2013 and $0.3 million in 2014. As standardized filing document PR-02 shows, applying the average general rate of increase for above-the-line rates to Miscellaneous Charges brings the rates closer to the actual costs of providing the service.

NS Power requests the Board's approval of these changes to Miscellaneous Charges as presented in standardized filing documents PR-02 and PR-03.

[87] NSPI 2006 General Rate Application, UARB Decision, NSUARB- NSPI-P-882, March 10, 2006, paragraph 610.

12 A FINAL WORD

This Application to increase electricity rates will make some Nova Scotians angry. The last several years have seen price increases for fuel, for energy efficiency, and for general rates. Because these increases are announced at different times of the year, it feels as though rates were going up continually. This impression, coupled with rising prices of other consumer goods and taxes, fuels our customers' displeasure. But as with our transformation to cleaner energy, we are turning the corner on rates.

This Application marks a milestone in our transformation plan. Since we began this transformation in 2009, we have invested more than $1 billion in a better future for Nova Scotians. That future will include 40 percent of our energy from renewable sources, hard caps on air pollution emissions, and the enhancement of Nova Scotia's position as a leader in environmental excellence.

We realize these improvements come at a price. We manage that price to the best of our ability. That is our job as Nova Scotians, and as your utility. This Application, and the Rate Stabilization Plan, represents NS Power's commitment to manage our costs through the end of 2014 without another application for a rate increase. We remain open to dialogue with customers and customer representatives on alternatives to traditional rate increases. We continue to work with our customers to find solutions when they fall behind on their bills. Independent performance audits consistently confirm that we run your utility efficiently.

"Efficiently" doesn't mean "perfectly". We understand that we are not meeting the expectations of all Nova Scotians. That remains a goal we strive for, so we have more work to do. We want to bring Nova Scotians the cleaner energy future they have asked us for, but we all have to face the reality that rising energy prices, at least in the short term, are a part of that future.

At NS Power, we absolutely believe the benefits – cleaner air, a modernized electrical system, freedom from volatile world coal markets – are worth it. By investing now in new facilities, we're keeping jobs and money at home, in place of sending money abroad to pay for high carbon, imported coal.

With this Application, NS Power seeks an order, effective January 1, 2013, approving:

- The 2013 and 2014 revenue requirements set out in this Application to enable NS Power to recover the reasonable costs of providing service to customers and to meet its financial obligations.

- The Rate Stabilization Plan, which provides for the recovery of the 2013 and 2014 revenue requirements as follows:

    - For each customer class, an average 3 percent increase on January 1, 2013 and an average 3 percent increase on January 1, 2014, after factoring in the 2010 FAM deferral reductions in 2013 and 2014,
    - Deferral of any portion of the Board approved revenue requirement not recovered by the average 3 percent annual increases. Effectively, this will continue the 2012 Fixed Cost Recovery deferral, which will continue to grow until the end of 2014, with recovery of the deferral over an 8 year period beginning in 2015,
    - FAM adjustments, other than for the 2010 FAM deferral reductions and the 2011 FAM imbalance both of which are reflected in the 2013 FAM Balance Adjustment, will be deferred, to be incorporated into customer rates in 2015.
    - The FAM incentive will remain suspended until the end of 2015.

The rates, charges and regulations requested in this Application.

- Changes to the Large Industrial Interruptible Rider and Load Retention Tariff Pricing Mechanism, as described in this Application.

- A change to Accounting Policy 5900 – Tax, to allow for the accounting of fixed cost recovery deferrals on a deferred tax basis, in order to align tax expense with the deferral recovery period.

- A change in the Open Access Transmission Tariff (OATT) rates described in this Application.

- Adjustments to the rates, charges, or regulations as needed to reflect decisions and directives in NS Power related proceedings or as the Board may determine in response to this Application.

- A return on common equity range held at the current 9.1 percent to 9.5 percent.

- In the alternative, recovery of the 2013 and 2014 revenue requirement using traditional rate-setting methodology as provided in the rates, charges and regulations contained in this Application.

We know rate increases create challenges for our customers. They add to the cost of running households and businesses. NS Power strives to ensure that electricity prices are as low as possible for our customers, and that price changes are as manageable as possible. That’s why we believe, in this time of transformation and investment, a multi-year plan is a better solution for customers than the traditional way of resetting rates.