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November 27, 2014

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, Newfoundland & Labrador
A1A 5B2

Attention: **Ms. Cheryl Blundon**
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro's 2013 AMENDED General Rate Application - Revisions

Enclosed please find the original plus 12 copies of revisions to the following sections of Hydro's Amended General Rate Application:

Volume 1
Rate Schedules – pg 43 of 46. The revision is necessary to correct a typo.

Section 2 - Regulated Activities – pgs 2.62, 2.64 and Schedule III. The revisions are necessary to correct for overstated transmission energy losses associated with recall energy on the Labrador Interconnected System.

All revisions have been shaded for ease of reference.

Should you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
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SECTION 2: REGULATED ACTIVITIES

2.1 OVERVIEW

Hydro's service territory encompasses a broad geographic area with challenging operating and environmental conditions such as high winds from severe cold, corrosive coastal areas and remote customer and facility locations. Maintaining, refurbishing and replacing the extensive power system infrastructure in a manner which provides safe, reliable and least cost service to its customers is the number one challenge faced by Hydro. Hydro has incurred, and is estimating a significant increase in capital expenditures during the period from 2007 to 2018, predominantly as a result of the need to rehabilitate and replace an increasingly aged asset base, as well as provide new assets to meet growth in customer demand. This requires Hydro to be diligent in the execution of its asset management strategy and the deployment of its workforce to be able to implement all aspects of the strategy. In addition, Hydro continues to rely on a significant amount of fossil fuel burning generating sources to meet customer requirements. The use of these sources will increase significantly in the short term as customer demand grows.

There are a number of factors which have created upward pressure on the cost of meeting customer electricity requirements since the last GRA:

- Increasing customer demand has created the requirement for capacity additions in order to increase generation reserves and provide reliable service on the Island Interconnected System. To address this requirement, Hydro is proceeding with the installation of a 123 MW combustion turbine at Holyrood and is also proposing capacity assistance agreements with two of its industrial customers.
- The cost of fuel has increased significantly.
    - At Holyrood, the forecast price of No. 6 fuel for 2015 has increased by more than 60 percent from the 2007 Test Year.

  - There has been a decline in fuel conversion rate at Holyrood in recent years due to lower production requirements, attributable to a number of factors, as well as a lower fuel heating content in the fuel since the switch to 0.7% sulfur in 2009.
  - The overall cost increase has been reduced from what it otherwise would have been by the purchase of lower priced energy from the two wind farms at St. Lawrence and Fermeuse and from the former Abitibi Consolidated generating assets that were used to supply the paper mill in Grand Falls-Winsor. These energy additions have helped to maintain Holyrood at nearly the same level of production as in the 2007 Test Year, despite significant customer load growth on the Island Interconnected System.
  - Fuel costs on the Isolated Systems have increased due to higher fuel prices and overall load growth experienced on the Labrador systems.
- Many of Hydro's assets have now reached the end of their expected service lives and many others are approaching that point. This has required increasing capital and O&M expenditures as well as increase in operations FTEs in order to provide reliable service to customers.
- There have been a number of salary and wage increases since the last GRA for both union and non-union employees. The increases help to ensure that Hydro is competitive in a tightening labor market and to improve its position from a recruitment and retention standpoint.
- On the Labrador Interconnected System, the long standing TwinCo arrangements are set to expire at the end of 2014. As the TwinCo assets are critical in providing reliable service to Hydro's customers in Labrador West, Hydro is in the process of acquiring the rights to these transmission assets either through purchase or leasing arrangements. Hydro has included

operating and maintenance costs for the former TwinCo transmission lines and Wabush Terminal station in its 2015 forecast.

The Regulated Activities evidence will provide further detail regarding these upward cost pressures as well as describe other activities under the following areas:

- The success Hydro has had in obtaining new renewable energy sources that have significant cost and environmental benefits through lower fuel consumption;
- Hydro's pursuit of operational excellence in safety, environmental responsibility, and reliability;
- Hydro's approach to asset management and the resulting changes in organizational structure;
- Workforce demographics and employee recruitment and retention initiatives;
- Operating expenses overview for the 2007 to 2015 period; and
- Hydro's load forecast and power supply arrangements.

2.2 NEW SOURCES OF ELECTRICITY AND OPTIMIZATION OF RESOURCES

2.2.1 Wind Power

The Province of Newfoundland and Labrador has a world-class wind regime that is being utilized on both the Island Interconnected and Isolated systems. Since 2007, Hydro has entered into new Power Purchase Agreements (PPAs) for wind energy on the Island Interconnected System. The PPA with Frontier Power for wind energy in Ramea remains in place. In addition, Hydro is now receiving energy from the Nalcor experimental Wind Hydrogen diesel plant in Ramea.

On the Island Interconnected System, wind energy has been generated at St. Lawrence since October 2008 and at Fermeuse since April 2009. There is a PPA in place with NeWind Group Inc. for the St. Lawrence wind energy and a PPA with Elemental Energy for the Fermeuse wind energy. At each site, there are nine 3 MW wind turbines, for a total installed capacity of 27 MW. In each full year of operation, the St. Lawrence site has produced, on average, more than 102 GWh, while the site at Fermeuse has produced more than 89 GWh. In 2013, the total Island Interconnected wind generation purchased was nearly 192 GWh. This level of energy production at Holyrood would require the consumption of nearly 305,000 barrels of oil, creating nearly 159,000 tonnes of GHGs.

On the Island Isolated System, Hydro has a PPA with Frontier Power for wind generation at Ramea. Frontier Power has six 65 kW wind turbines installed for a total capacity of 390 kW. From 2006 to 2013, the wind generation from Frontier Power has produced, on average, 10% of Ramea's annual energy requirements. In 2013, 637 MWh or 14.4% of Ramea's total energy requirements of 4,438 MWh were produced from Frontier Power's wind turbines. This resulted in a reduction of diesel fuel usage at Ramea of approximately 178,000 litres with a displacement of 550 tonnes of GHGs.

2.2.2 Exploits Generation

In December of 2008, the Government expropriated the generating assets at Grand Falls, Bishop's Falls, Buchans and Star Lake following the announced closure of the paper mill in Grand Falls-Windsor. Nalcor received the license to operate the assets, and, in February of 2009, cessation of paper-making operations resulted in there being surplus power and energy from the Grand Falls, Bishop's Falls and Buchans generating facilities. As directed by Government, the energy from Star Lake and the Incremental Generation[1] at Grand Falls and Bishop's Falls continued to be available to Hydro under the terms of the PPAs which were with the Star Lake Hydro Partnership and the Exploits River Hydro

[1] Generation in excess of 54 MW at Grand Falls and Bishop's Falls.

Partnership, respectively. The surplus power and energy resulted from the Base Generation[2] which was previously used by ACI to supply the paper mill operations.

Hydro continued to purchase the Incremental Generation and Star Lake energy at the rates specified in the PPAs up to December 31, 2010. The Base Generation energy was not purchased by Hydro because it held no value due to 1) the significant load reductions at the Grand Falls and Corner Brook paper mills, and 2) new wind energy sources at St. Lawrence and Fermeuse. The combined effect of these Industrial Customer load reductions and new wind energy sources was sufficient for Holyrood to be reduced to minimum output.

Subsequent to the paper mill closure, Nalcor Energy was unable to reduce the flow of water in the Exploits River to store the water in the Red Indian Lake reservoir for later production, as this reservoir did not have sufficient space. Furthermore, it had to meet minimum flow requirements in the Exploits River. As a result, Hydro took receipt of the Base Generation rather than having the generating plants on the Exploits River shut down and the energy lost. This was done by displacing Hydro's hydraulic production, resulting in increased water levels in Hydro's reservoirs. This action, in effect, enabled the storage of the Base Generation for potential future disposition unless it caused water spillage from Hydro's reservoirs. If there was water spillage from Hydro's reservoirs, the equivalent energy in the spilled water would be deemed to be from the Base Generation and would no longer be available for future use. Spillage did occur in 2010 and 2011, resulting in all of the Base Generation energy produced up to the end of 2011, except 448 GWh, being spilled.

On July 25, 2011, Hydro received Government direction to pay for energy received from the Grand Falls, Bishop's Falls, Buchans and Star Lake facilities at 4¢/kWh, effective

[2] Generation up to 54 MW at Grand Falls and Bishop's Falls and generation from the Buchan's hydroelectric plant.

January 1, 2011. In a letter to Hydro dated December 2, 2013, Government indicated its intention to transfer ownership of the Exploits generation facilities from Government to Hydro. While no further correspondence from Government has been received, until the end of the 2015 Test Year the price for purchases is assumed to equal the 4¢ per kWh, as previously directed by the Government.

The following table outlines the purchases from these facilities since February 12, 2009. The 2015 production level from the Exploits Generation is forecast to be 776 GWh. A detailed description of the methodology and assumptions used in the 2015 hydraulic generation forecast is in Section 2.7.

Table 2.1

Energy Purchases from Exploits Generation
February 12, 2009 - December 31, 2015 (Forecast)

			Exploits River Project	Star Lake	Nalcor Grand Falls, Bishops Falls and Buchans[1]	Totals
2009	Energy	(GWh)	161	126	-	287
	Cost	($000)	12,427	8,674	-	21,101
2010	Energy	(GWh)	112	140	-	252
	Cost	($000)	8,664	11,232	-	19,896
2011	Energy	(GWh)		130	511	641
	Cost	($000)		5,193	20,425	25,618
2012	Energy	(GWh)		144	586	730
	Cost	($000)		5,778	23,436	29,214
2013	Energy	(GWh)		141	600	741
	Cost	($000)		5,624	23,989	29,613
2014F	Energy	(GWh)		145	612	757
	Cost	($000)		5,893	24,384	30,277
2015F	Energy	(GWh)		142	634	776
	Cost	($000)		5,687	25,340	31,027

Notes:
[1] The base energy from the Nalcor operated generation at Grand Falls, Bishops Falls and Buchans became available to the Island Interconnected System following shutdown of the paper mill on February 12, 2009.

2.2.3 Conservation and Demand Management

During its 2006 GRA, Hydro outlined its planned approach regarding energy conservation. As described in Exhibit 1 of this evidence, an energy efficiency team has been established with a mandate to develop and implement demand and energy conservation programs both internally for Hydro and externally for customers. The following is a summary of the energy savings related to the activities completed as of December 31, 2013, and forecast for 2014.

Table 2.2

Hydro Customer and Internal Annual Energy Savings (MWh)						
Customer Energy Conservation Programs	**2009**	**2010**	**2011**	**2012**	**2013**	**2014(F)**
Windows	13	37	61	136	99	75
Insulation	35	126	404	382	794	114
Thermostats	9	35	30	53	24	13
Coupon Program	-	64	256	-	-	-
Commercial Lighting	3	10	227	95	99	73
Block Heater Timer					288	-
Isolated Systems Energy Efficiency Program				1,676	1,096	600
Isolated Systems Business Efficiency Program				3	27	50
High Efficiency HRV					1	6
Business Efficiency Program						64
Small Technologies Program						65
Residential & Commercial Customer Energy Savings	**60**	**272**	**978**	**2,345**	**2,428**	**1,060**
Industrial Customer Energy Savings	-	-	165	3,172	-	15,000
Total Customer Program Energy Savings	**60**	**272**	**1,143**	**5,517**	**2,428**	**16,060**
Hydro Internal Energy Savings	1,391	453	232	279	851	350
Total Customer and Hydro Internal Energy Savings	**1,451**	**725**	**1,375**	**5,796**	**3,279**	**16,410**

CDM activities since 2007 include:

- Participation, along with NP, in the production of two five-year CDM plans;
- Participation in and promotion of rebate programs related to energy efficient products;
- Participation in government sponsored conservation activities;

- Establishment, in partnership with NP, of the takeCHARGE brand for energy efficiency programs;
- Participation in trade shows and presentations;
- Establishment of customer and class-specific programs; and
- Establishment of internal energy efficiency activities at Hydro's facilities to improve lighting and HVAC efficiency.

2.2.4 Ramea Wind-Hydrogen-Diesel Facility

The Ramea Wind-Hydrogen-Diesel facility is a Research and Development (R&D) project, the capital costs for which were not incurred by the ratepayer. The construction and installation of the wind-diesel system was approved by Board Order No. P.U. 31(2007). The scope of the project involved the supply, installation and commissioning of the following major components:

- Energy Management System;
- Hydrogen (H_2) Electrolyser;
- H_2 Internal Combustion Engine Genset – five 50 kW Units;
- H_2 Storage;
- System Integration components; and
- Wind Farm – three 100 kW Units.

The purpose of this R&D effort is to lay the groundwork for further study of the potential to provide a cost-effective, renewable energy alternative to remote diesel systems. Since 2007, the project has had a number of technical challenges that have delayed its completion. Most of the delays have been associated with late deliveries of specialized equipment or were a result of the challenges associated with this new technology. Nalcor will continue to study the economics of operating and maintaining this system while considering the environmental benefits of reduced diesel fuel consumption. The study will also provide for technical learning opportunities to develop techniques to fully optimize project components for possible future installations.

Despite delays and integration issues, the first energy was produced from the wind generation on December 12, 2009. Over the course of its operation, and up to December 31, 2013, 616 MWh of energy have been produced for the community. This has resulted in a total reduction in diesel fuel usage at Ramea of approximately 172,000 litres and a displacement of 530 tonnes of GHGs.

Hydro is forecasting 145 MWh and 200 MWh of production in 2014 and 2015, respectively, from the Nalcor Ramea wind generation facility which will help to offset diesel fuel usage and result in a further displacement of greenhouse gas emissions.

2.2.5 Labrador TwinCo Power and Assets

The Twin Falls Power Corporation (TwinCo) Block of power is produced by Churchill Falls Labrador Corporation (CF(L)Co) at the Churchill Falls Generating Station and delivered to TwinCo at a delivery point near Churchill Falls. It is a firm 225 MW, 100% capacity factor block of power and energy, resulting in 1,971 GWh per year. It is currently resold by TwinCo to Wabush Mines[3] and the Iron Ore Company of Canada (IOCC) for their iron mining operations in Labrador West.

The transmission lines from Churchill Falls to Labrador West are constructed and operated on land which is subleased from CF(L)Co by TwinCo. There are two parallel lines (Lines 23 and 24) which are operated at a nominal 230 kV voltage with a total length of approximately 470 km. These transmission lines serve both the iron ore mines of IOCC and Wabush Mines as well as Hydro Rural Customers in Labrador West. The lines are maintained by CF(L)Co on behalf of TwinCo with no costs passed on to Hydro. The long standing sublease expires at the end of 2014 at which time the transmission lines will become the assets of CF(L)Co.

[3] In October 2014, Cliff Natural Resources announced its plans to officially close Wabush Mines.

The transmission assets in Labrador West also include the equipment in the Wabush Terminal Station. Most of these assets are also owned by TwinCo and reside on land that is currently being leased from Wabush Mines. This lease also expires at the end of 2014. The major equipment generally consists of eight 230 kV/46 kV power transformers, three synchronous condensers and ancillary equipment (for voltage support), 13 - 230 kV circuit breakers, 18 – 46 kV circuit breakers, 230 and 46 kV disconnect switches, station service equipment and protection and control equipment. This equipment, with the exception of the third synchronous condenser[4], is also maintained by CF(L)Co on behalf of TwinCo. The capital and operating and maintenance costs associated with the two original synchronous condensers are shared between IOCC and Hydro under an agreement which expires at the end of 2014, with Hydro's portion recovered from Hydro Rural Customers. The Labrador Interconnected System - Plant Assignment drawing in Exhibit 3 of this GRA illustrates the configuration of this equipment.

As these assets are critical to providing reliable service to Hydro's customers, Hydro is in the process of acquiring the rights to these transmission assets either through purchase or leasing arrangements from the three parties involved. The arrangements for either lease or purchase will be in place by the end of 2014. For the purpose of determining 2015 proposed rates for Hydro Rural and Labrador Industrial Customers, Hydro's 2015 Test Year includes forecast operating and maintenance costs of approximately $2.8 million for the transmission lines and the terminal station. Once discussions with the parties are finalized, Hydro will be requesting Board approval of any asset acquisitions and will request approval of future required capital expenditures for the former TwinCo assets consistent with the capital budget expenditure guidelines established by the Board.

[4] This unit is installed and owned by IOCC.

2.2.6 Expanded Generation Capacity to meet Customer Demand

Customer demand for electricity has been growing due to the economic growth within the Province. This has led to the requirement for capacity to be added to the existing Island Interconnected System generation capacity before the end of 2015 in order to provide reliable service to customers. To address these requirements Hydro is placing in service a 123 MW combustion turbine late in 2014 and is also proposing the implementation of capacity assistance agreements with its Industrial Customers as outlined below.

2.2.7 Capacity Assistance Arrangements

The proposed agreement with Corner Brook Pulp and Paper Limited (CBPP) will allow Hydro to call on CBPP for its ability to provide up to 60 MW capacity assistance to Hydro during winter peak demand periods by both reducing its firm demand supplied by Hydro, and by providing capacity to Hydro's system from the CBPP hydraulic generating facilities. Hydro is also discussing a capacity assistance agreement with Vale. Under the arrangements with this customer, it is anticipated that Vale will provide up to 15.8 MW of capacity support from its local diesel generation at Hydro's request. The 2015 Test Year forecast assumes an annual cost of $2.1 million for these arrangements.

2.2.8 New Combustion Turbine

Hydro is proceeding with the addition of a combustion turbine (CT) generator with an early in-service of late 2014 to provide additional reserve capacity earlier than originally planned. Work is currently ongoing to install a 123 MW unit and auxiliary equipment at Holyrood with a planned in-service in December 2014. The unit will serve several functions:

- Additional long term generation capacity and increased generation reserves for the Island Interconnected System;
- Additional generation capacity on the Avalon Peninsula to mitigate local generation supply and transmission contingencies; and

- Local generation at the Holyrood Generating Station for the provision of Black start and station service requirements.

The capital cost of the project is $119 million and approval for construction was received under Board Order No. P.U. 16(2014).

2.3 OPERATIONAL EXCELLENCE

Hydro is focused on delivering value to the electricity consumers of the Province through operational excellence.

2.3.1 Safety and Health

Foremost among Hydro's goals is the safety of its employees, contractors, and the general public. The Company has a targeted approach towards injury prevention, communication and awareness, and visible leadership and support at all levels. There is also a focus on supporting and recognizing the areas with exceptional safety performance to enable continued motivation and sustain a positive and strong safety culture.

A company-wide process for collecting and reporting hazards, near misses and both safe and unsafe practice observations remains a key component of Hydro's safety program. This Safe Workplace Observation Program (SWOP) focuses on reporting safety observations. This data is used to identify actions to continually improve safety for employees, contractors and the public. Hydro continues to strengthen its focus on the Work Protection Code[5], Work Methods[6] and Grounding and Bonding[7] which are

[5] The Work Protection Code is a document containing rules which must be followed by all individuals required to perform work on transmission and distribution systems, auxiliary metering circuits, and at generating facilities. The rules and procedures ensure protection for individuals working in an environment into which harmful energy can be introduced.

[6] Work Methods are documents that instruct employees on how to properly perform critical tasks in a safe manner.

[7] The Grounding and Bonding Program identifies practices for temporary grounding of electricity generation equipment and transmission and distribution lines to provide maximum protection for workers.

fundamental components of a utility's safety program. Hydro's safety program has been a joint union and company effort, and its current success can be attributed to the broader involvement by both union and non-union workers. As a result of the data collected from the SWOP database, Hydro increased its engagement in enabling contractor safety, promoting public safety around electrical equipment, and standardizing and increasing awareness of permits required to complete work near a transmission or distribution line. These efforts contribute to overall safety.

Hydro also has wellness programs for employees which have focused mainly on heart health, with initiatives including wellness clinics, stress management sessions, and fitness reimbursement programs for certain wellness related activities.

2.3.2 Environmental Performance and Air Emissions

Over the past few years, Hydro has improved its environmental performance, while maintaining the safe and reliable delivery of energy to residents of the Province. Hydro's commitment to the environment helps ensure a healthy and sustainable environment for future generations of Newfoundlanders and Labradorians. To facilitate this environmental performance, Hydro continues to use the ISO 14001 Certified Environmental Management Systems, which provide a framework for an organization's environmental responsibilities and is an integral component of the organization's business operations and continuous improvement focus.

The environmental commitment to sustainable practices in its operations is demonstrated throughout the Company's activities. Hydro has integrated initiatives in alternative energy, energy conservation and community partnerships into its operations throughout the Province. Hydro also takes its responsibility to preserve sensitive habitats and vegetation very seriously and makes every effort to ensure minimal environmental impacts through its operations.

Environmental Management Areas

Currently there are four Environmental Management areas[8] within Hydro with identified environmental aspects. Environmental aspects are elements of a department's activities, products, or services that can interact with the environment. Significant environmental aspects are managed either through Environmental Management Programs or standard operating procedures.

In 2013, Hydro completed 95% of its Environmental Management Systems targets, which are initiatives undertaken to improve environmental performance.

Emissions

In 2013, approximately 82% of the net electricity supplied by Hydro was generated from clean hydroelectric power. However, to reliably meet all the electricity demand each year, and to supplement Hydro's hydroelectric generation and purchases, a portion of the Island Interconnected System electricity still must come from fossil-fuel fired generation at Holyrood and at times from gas turbines. From 2007 to 2013, 13 to 20% of the Island Interconnected System net energy requirements were supplied by Holyrood. Hydro also owns and operates 25[9] diesel plants across the Province, primarily to supply isolated communities. In 2013, approximately 72% of the supply in these isolated areas was from fossil fuel generation.

Since 2007, the Company has incorporated additional alternative sources of energy into the Province's energy supply to reduce emissions from burning fossil fuels and the related costs. As stated previously, in 2013, Hydro purchased nearly 192 GWh of clean energy from the two Island Interconnected wind projects.

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[8] Services Management, Thermal Generation, Hydro Generation and Transmission and Rural Operations.

[9] Includes 21 Isolated diesel plants, and diesel units in St. Anthony, Hawkes Bay, Happy Valley-Goose Bay and Mud Lake. Hydro operates and maintains the diesel plant in Natuashish on behalf of the Mushuau Innu First Nation.

Overall, thermal production at Holyrood increased in 2013 by 11.7% from 2012, primarily due to increased requirements from the plant for Avalon transmission support and higher system peaking requirements. This was primarily driven by colder temperatures and increased customer demand. The Holyrood plant produced just over 14% of the energy supplied by Hydro in 2013, up slightly from 13% in 2012. The increased energy production from the Holyrood plant in 2013 resulted in a 10.9% increase in carbon dioxide (CO_2) emissions. The increase in CO_2 emissions is directly attributed to more fuel being consumed in 2013, relative to 2012. The sulphur dioxide (SO_2) emissions from the plant in 2013 were 8.1% higher than those experienced in 2012.

Total emissions for CO_2, and SO_2 for Holyrood, gas turbine facilities and isolated diesel generating stations are calculated using formulas approved by the provincial Department of Environment and Conservation. Hydro's overall air emissions are dominated by those resulting from production at the Holyrood Generating Station.

Emissions for the Island Interconnected System, including Holyrood, and interconnected gas turbines and the standby diesel plants are outlined in the following charts:

1 **Chart 2.1**

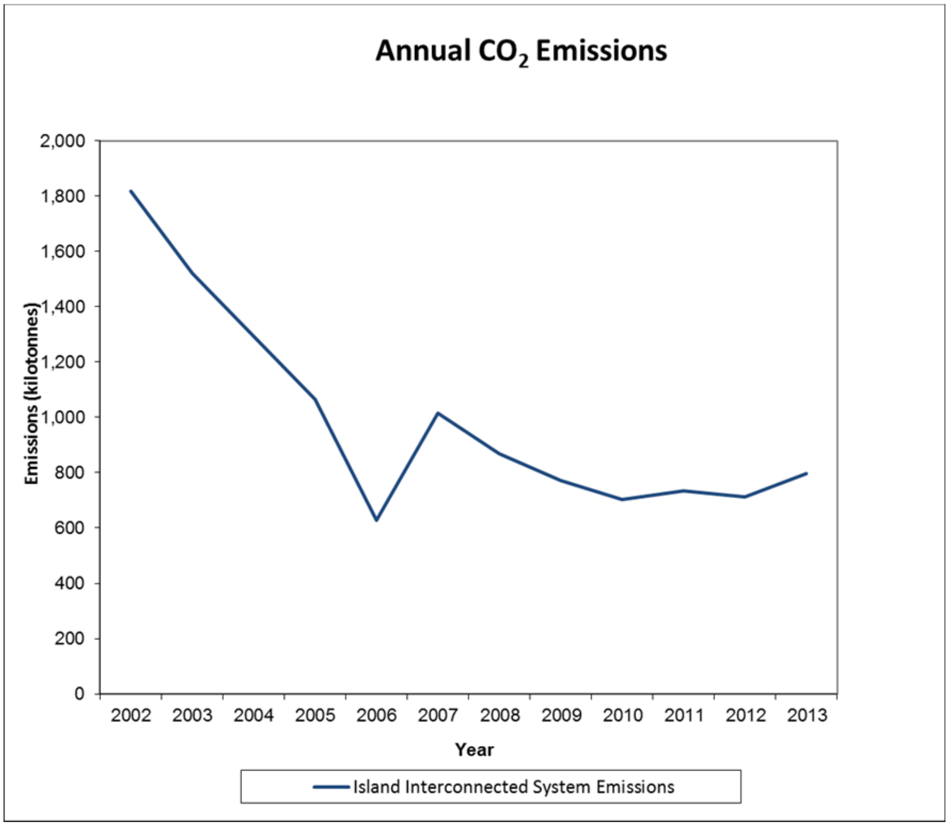
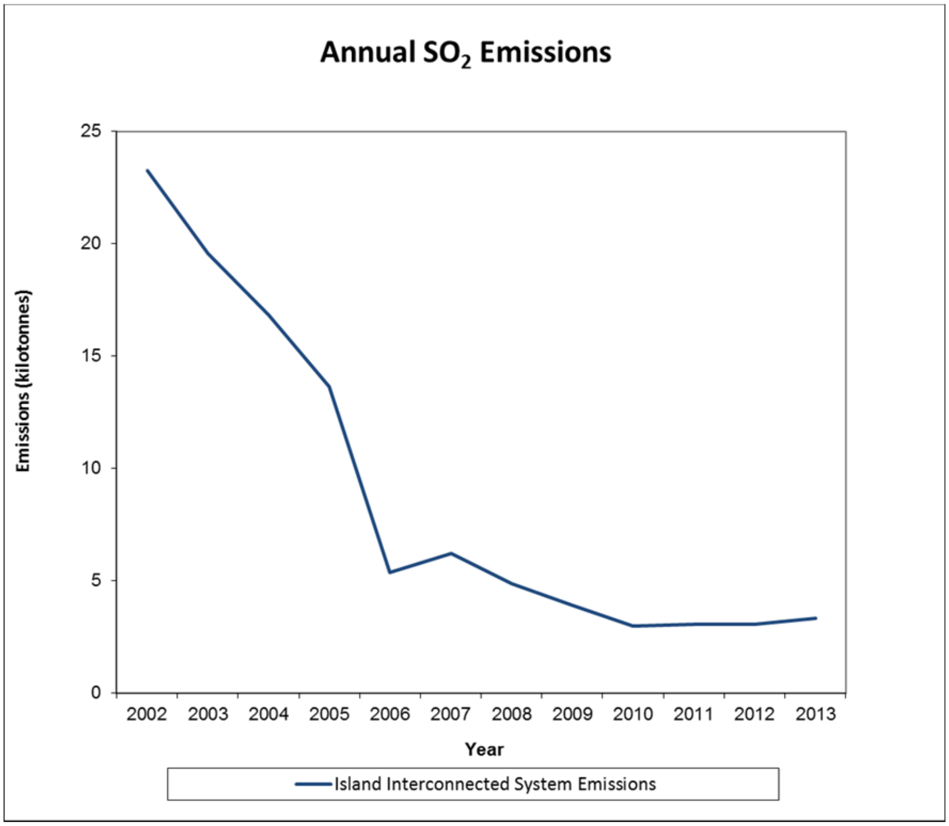

Annual CO_2 Emissions
Emissions (kilotonnes)
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Year
Island Interconnected System Emissions

Chart 2.2



Emissions of CO_2 and SO_2 for Hydro's other systems in 2013 were calculated to be approximately 47.8 and 0.06 kilotonnes, respectively.

2.3.3 Asset Management and Capital Investment with an Aging Asset Base

Hydro's responsibility to provide reliable and least cost service to meet the needs of its customers is a challenging balance which is addressed through sound asset management. This approach requires that assets are kept in reliable working condition through a structured preventative maintenance program, with the required corrective maintenance and replacement or refurbishment when necessary. Asset replacements are planned based on condition assessments, maintenance and operating history, changing technology, expected service lives and knowledge of individual assets. Asset additions and upgrades are also determined through analysis of options to address the long-term, least cost supply of electricity.

The current condition of Hydro’s asset base is a reflection of the history of the electricity industry in general and, in particular, the Province. In the 1960s, there was a significant expansion in assets to fulfill the mandate of the Newfoundland and Labrador Power Commission, Hydro's predecessor, which was to bring electricity to many areas of the Province and to build an infrastructure which connected the many diverse and isolated electrical systems in the Province. Many of the assets constructed during that time have now reached the end of their expected service lives and many others are approaching that point. Other major assets, such as hydroelectric plants like the Bay d'Espoir Generating Station, have not reached the end of their expected service lives, however, some of the components, auxiliary equipment and systems are at, or near, the end of their service lives. This, along with increasing upward pressure on labour and material market costs, has resulted in growth of Hydro’s capital investments which is expected to be sustained at a higher level for the near term.

In 2006, Hydro undertook an assessment of its asset management process in recognition of its aging asset base. Figure 2.1 summarizes the progression of this assessment and action items.

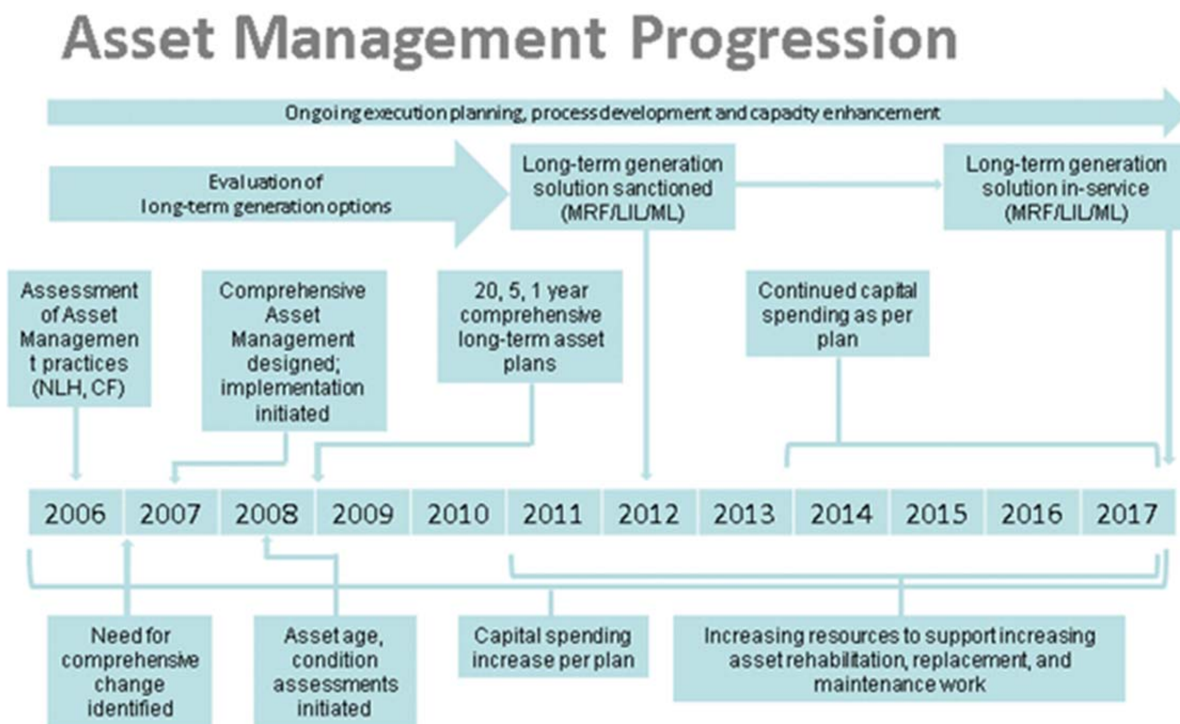


Figure 2.1 - Asset Management Progression

Asset management activities have focused on:

- Reviewing the five year capital plan, updating both the content and timing of projects based on knowledge gained from inspections (e.g. onsite physical inspections as well as feedback from hands-on operators and maintainers) and targeted formal condition assessments;
- Updating the full 20 year capital plan;
- Preparing and executing plans to update:
  - critical spare requirements; and
  - standards, planning criteria and operating parameters;
- Updating metrics for asset management;
- Developing a consistent approach to performing root cause failure investigation; and

- Process improvements for Project Execution and Short Term Work Planning and Scheduling, including integrated resource planning and standardized progress tracking.

In 2010, Hydro updated its organizational structure to support a renewed Asset Management Strategy which aligns with:

- Asset performance expectations;
- Consistent maintenance practices for similar assets; and
- Asset renewal or replacement programs.

As a result of this reorganization, five key functions have been established consistently throughout all operating departments.

1. Long-Term Asset Planning;
2. Short-Term Work Planning and Scheduling;
3. Work Execution;
4. Operations; and
5. Support Services.

Figure 2.2 shows a representative organizational structure reflecting these functions.

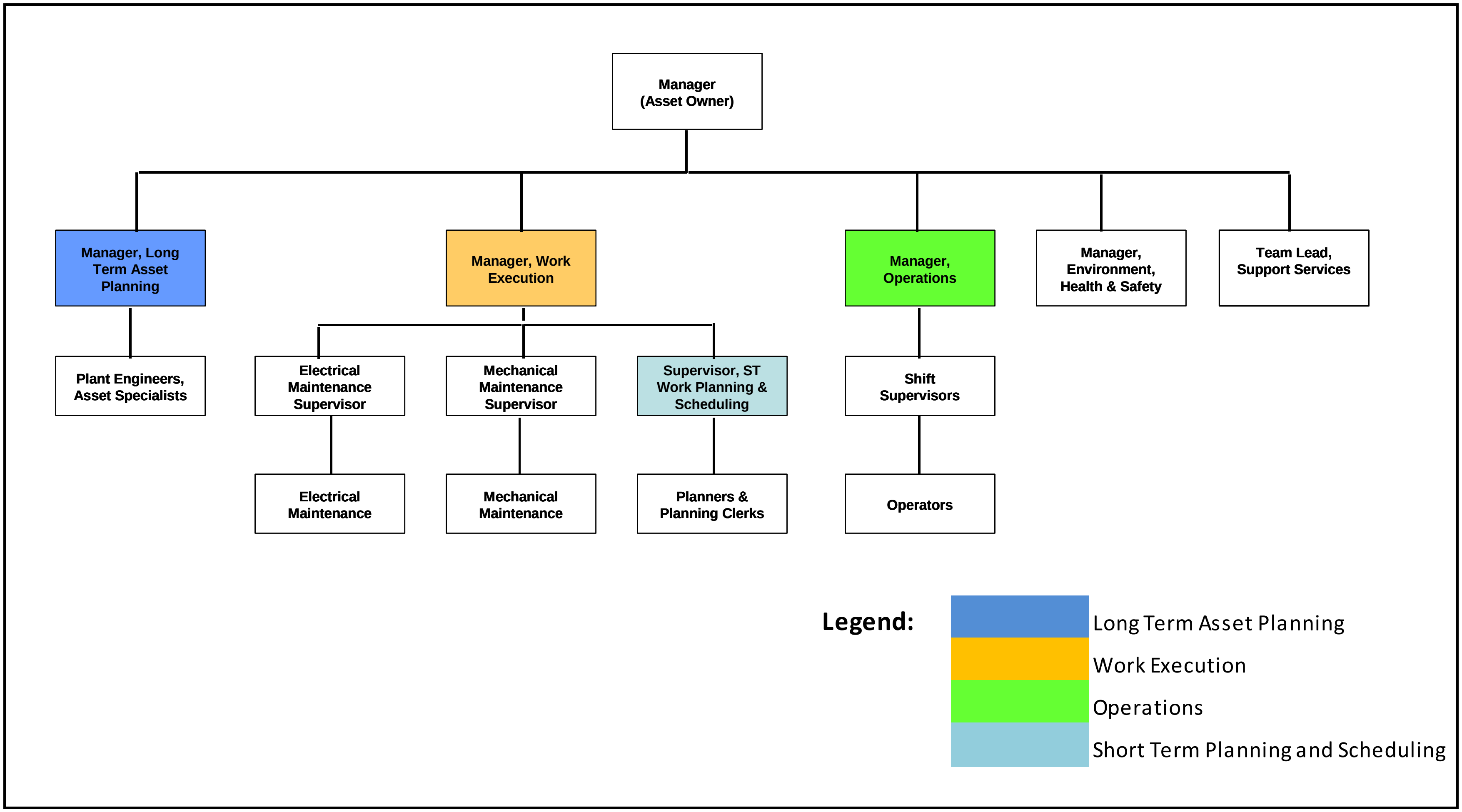


Figure 2.2 - Asset Management Representative Organizational Structure

In addition to the changes in the operating departments, a centralized Office of Asset Management (OAM) was created in the Project Execution and Technical Services division. The OAM has responsibility for oversight and direction for asset management and provides support to the operating departments, ensuring a consistent implementation of asset management best practices throughout the Company.

These changes in roles are included in Exhibit 1, Organizational Responsibility.

As part of its ongoing asset management strategy Hydro reviews its workforce capacity to address any changes required to meet the challenges of both an aging and growing asset base. In 2014 and 2015 it has made adjustments to staffing levels in a number of key areas to meet growing customer demand, an increasing capital program and a greater requirement for execution of required preventative and corrective maintenance relating to Hydro's aging assets. There has been an increase in Full Time Equivalents (FTEs) throughout the Company with particular focus in Operations areas. In 2014, there are 861 operating FTEs, an increase of 44 FTEs over the 2007 Actual. In 2015, there is a further increase of 34 FTEs for a total of 895 operating FTEs. The planned increases in the Operations area provide for additional execution capacity and enhanced planning and scheduling to complement the increased capital program and increasing maintenance requirements resulting from aging assets and their replacements. These positions are critical for the delivery of sustained reliable service to customers. The additions are further described and explained in the Section 2.4 functional area cost reviews.

Holyrood

Holyrood is the second largest generating plant on the Island Interconnected System, and, as a thermal plant, is significantly more complex than its hydroelectric counterparts. Units 1, 2 and 3 were put in service in 1970, 1971, and 1980, respectively. Each has passed the normal 30-year design life for such a facility and has undergone life extension activities. Units 1 and 2 were modified in the late 1980s to increase their capacity from 150 to 170 MW each. This was achieved by availing of the overcapacity inherently designed in equipment of that vintage and by modifying the plant's auxiliary systems. Units of a similar age in other electric utilities have been retired or have been subjected to life assessment and extension studies. Those not retired received costly major refurbishments to extend their useful lives.

Maintaining Holyrood as a reliable source of energy and capacity for the Island Interconnected System is essential prior to the Labrador interconnection. The closure of the paper mill at Grand Falls-Winsor, the reductions in load at CBPP and the development of two wind farms have resulted in reduced energy requirements from Holyrood in recent years. However, Holyrood remains a vital generation asset for capacity and energy, particularly in light of growing customer demand due to utility load increases and the ramp up of operations at the Vale nickel processing facility. It should also be noted that during a repeat of the critical dry sequence, annual required production from Holyrood would be significant, up to 3,000 GWh per year. In addition to ensuring reliability, environmental issues with the plant and various legislative and regulatory requirements contribute to ongoing significant expenditures at the facility.

To enhance the reliability of supply from Holyrood, Hydro has recently installed and commissioned eight mobile Black start diesel units at the facility. Installation took place during the winter of 2014 with the final plant interconnection occurring in early April 2014. The units were fully commissioned in July 2014 when a Black start test could be performed. The diesel units provide for several functions:

- Black start capability of Holyrood in the event of an extended transmission outage that separates the Avalon Peninsula from the remainder of the Island Interconnected System grid;

- In the event of an extended transmission outage into the facility, pre-warming capabilities and other essential and auxiliary services for the plant which will reduce the overall outage time once transmission is restored; and
- Peaking capacity of up to 10 MW to the grid.

The total lease and capital costs associated with this project were $6.5 million and approval for construction was received under Board Order No. P.U. 38(2013). The leased diesel units will be returned to the supplier at the end of June 2015 as they will be no longer required at that time due to the installation of the new Holyrood CT.

2.3.4 Recent Reliability Performance

As part of its asset management strategy, Hydro continually monitors the performance, condition and increasing age of its assets and their components to detect the early onset of failure. To enable a rapid response to failures Hydro continues to increase its capacity to repair and maintain through additions of both internal and external resources, as appropriate for the assets' position on their life cycle curves and the increased potential for failure. Also, as part of Hydro's asset management strategy, Hydro reviews significant asset failure incidents to determine root causes and to implement improvements to prevent recurrence.

In 2013, there were a number of severe weather related events that negatively impacted Hydro's reliability performance. The events of January 11, 2013, which were initiated by high winds and salt contaminated snow at the Holyrood switchyard, resulted in widespread customer outages in many areas of the Province. Following the events of January 2013, Hydro undertook a review of the power system response and identified and implemented a number of recommendations that primarily targeted enhancements to and replacements of high voltage and protection and control equipment, power system studies and a review of preventative maintenance and operating procedures.

The events of January 2014 were driven by an abnormal combination of generation equipment problems followed by transmission breaker failures during an extended period of cold weather. Hydro recognizes the significant impact these events had on customers and is committed to reducing the impact and likelihood of it reoccurring. Hydro has subsequently made changes to improve reliability. The more significant initiatives are as follows:

- Enhanced senior leadership and oversight of critical operations, namely a General Manager for gas turbines and diesels;
- Accelerated the addition of the combustion turbine generator to 2014 from 2015 to provide additional reserve capacity a year earlier than originally planned;
- Following from the work initiated in 2013 to update previous critical spares reviews, an accelerated review and update to include all generation equipment was undertaken in 2014;
- Modified the established air blast circuit breaker replacement program to have an earlier completion with more replacements in 2015;
- Specific focus on identified protection and control improvements;
- Completion of the remaining circuit breaker and transformer preventive maintenance work that was included in the six year recovery plan (2010 to 2015), by completing approximately 50% of the remaining work in 2014 and the remainder in 2015; and
- Obtained an agreement with CBPP for 60 MW of capacity assistance. Hydro is also working on a capacity assistance agreement with Vale for up to 15.8MW of capacity support.

Also, the following actions which Hydro had previously planned and/or which were identified during ongoing asset management activities in 2014 were undertaken:

- Upgrading of two transformers at Oxen Pond for load growth;

- Installation of three Labrador Island Link related 230 kV breaker upgrades at the Holyrood Terminal Station;
- Planned refurbishment of the Stephenville Gas Turbine;
- Initiation of a program of scheduled battery discharge testing to ensure that protection and control systems will operate reliably when required;
- Execution of recommended modifications to electrical grid protection and control systems;
- Replacement of insulators on TL201 and TL203 to address age related deterioration;
- Implementation of an enhanced winter readiness program in all operating areas to build on existing activities in place for preparing for the high winter demand period; and
- Advancement of the excitation transformer replacement program at Bay d'Espoir.

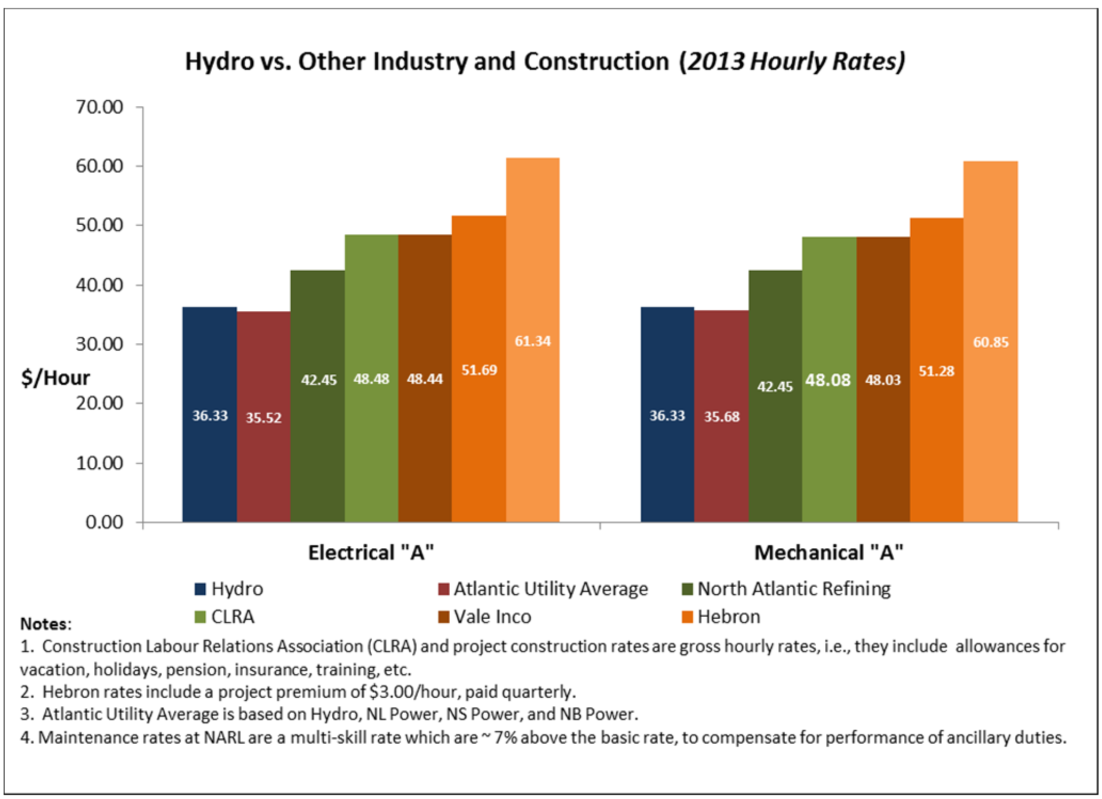
2.3.5 Maintaining a Skilled Workforce

A skilled and motivated workforce is critical for ensuring safe and reliable service to Hydro's customers. In 2006, a focus on recruitment and retention was initiated as there was increasing incidence of voluntary resignations. A key aspect of Hydro's recruitment and retention strategy has been to ensure the Company is competitive on salaries and wages in an increasingly tight labour market. Hydro has expended considerable effort to ensure its compensation is adequate to both attract and retain quality employees, while maintaining cost control on behalf of customers. There still remain additional challenges to incent resources to work in rural areas.

With respect to its unionized groups, Hydro negotiated two series of special wage adjustments in order to bring its employees' wages in line with NP and the average wages of other Atlantic Canada electric utilities. Over the period 2007-2009, trades and technology employees, who represent the significant majority of Hydro's operations group, received an additional $1.65/hour wage and benefit increase to help close this gap. In 2010, a further trades adjustment of approximately 4.8%, plus annual general adjustments of 6.5%, 4%, 4%, and 4% over the period 2010 to 2013 were negotiated in order to completely close the gap and achieve parity and competitive positioning with other Atlantic Canada electric utilities to aid in recruitment and retention efforts.

An additional factor for Hydro in applying these changes has been the rates paid in the provincial construction industry. Chart 2.3 presents a comparison of 2013 rates between Hydro, the average across the Atlantic Canada electric utilities and the provincial construction rates, using Electrical "A" and Mechanical "A" as reference points. While it is not necessary to fully match the construction rates in order to be competitive, it is imperative that the Company wage rates are in reasonable proximity from a recruitment and retention standpoint. Hydro will continue to monitor its positioning relative to these sectors.

Chart 2.3



In its non-union group, annual general economic adjustments mirrored those that were provided to the Company's unionized employees over the period 2010 to 2013. In addition, in 2007 it was necessary to re-establish the historical wage differential between front-line supervisors and their trades and technology employees. In the absence of this adjustment, the differential of between 17% and 20% which existed before market adjustments initiated in 2007 would have eventually eroded to below 10%, causing difficulties from an internal recruitment and retention standpoint in relation to front-line supervisors.

Additionally, in 2012 a number of non-union salary scales were adjusted upwards by 1.3% to 7.9% based on an analysis of non-union salaries. The adjustments were required to ensure Hydro is more competitive with the external labour market.

All of the above compensation measures resulted in annual wage and salary increases which have been above the rate of inflation. However, in all cases, they have been implemented for sound recruitment and retention reasons, and to help ensure the sustainability of Hydro's operations. Increased recruitment needs driven by retirements, in the context of an increasingly tight and changing labour market, have compelled the Company to take the steps necessary to ensure it can minimize the loss of knowledge and skills. The electric utility industry is highly specialized and Hydro has taken action to compete for the people and skills it requires to maintain operations and complete its increasing capital program.

As in the past, Hydro will continue to take a multi-faceted approach to its recruitment and retention strategy, by emphasizing non-compensation initiatives as well as compensation-based approaches. This will include a continuing focus on Apprenticeship and Engineer in Training programs, assessing the possible redeployment of FTEs when vacancies occur, focusing on employee engagement, and implementing organizational and process efficiencies where appropriate.

Hydro does anticipate that the challenge of maintaining wage and salary costs within inflationary levels will continue. High levels of recruitment, driven by retirements, high levels of construction and major project activity in the Province and elsewhere, and a shrinking labour force will continue to place pressure on wage and salary competitiveness.

The collective agreements for Hydro's unionized employees expired as of March 31, 2014. Hydro and the IBEW are currently in negotiations for new collective agreements.

2.4 OPERATING EXPENSES

This section provides an overview of Hydro's Operating Expenses for the 2014 and 2015 Test Years with variance explanations to the 2007 actuals. Operating expenses are shown by both cost category and functional areas. Cost category is comprised of three major classifications: Salaries and Benefits, System Equipment Maintenance (SEM) and Other Operating Expenses, shown in Schedule 1, page 9 of 11 in Section 3 of this evidence. Functional areas include Operations and Corporate Services. Operations is comprised of Transmission and Rural Operations (TRO), Generation, and System Operations and Planning. Corporate Services includes Leadership and Associates, Human Resources and Organizational Effectiveness (HROE), Finance, Project Execution and Technical Services, and Corporate Relations. An overview of operational expenses by functional area is provided in Schedule 1 of this evidence.

Cost recoveries related to operating expenses are also discussed in this section. Cost recovery is related to services provided by Hydro to other Nalcor lines of business or external parties as well as cost deferrals associated with the CDM program. The cost recovery methodology is explained in Section 3.4.2.

2.4.1 Operating Expenses by Cost Category

A breakdown of operating expenses by cost category is shown in Table 2.3.

Table 2.3

Operating Expense by Cost Category ($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY vs. 2007A Change	2015 Test Year	2015TY vs. 2007A Change
Salaries and Benefits	58.3	73.3	78.0	19.7	85.8	27.5
System Equipment Maintenance	23.1	21.4	22.4	(0.7)	26.3	3.2
Other Operating Expenses	19.2	21.8	29.6	10.4	28.6	9.4
Total Operating Expenses Before Other Cost Recoveries	**100.6**	**116.5**	**130.0**	**29.4**	**140.7**	**40.1**
Other Cost Recoveries	(2.9)	(4.7)	(3.9)	(1.0)	(2.5)	0.4
Total Operating Expenses	**97.7**	**111.8**	**126.1**	**28.4**	**138.2**	**40.5**

Total operating expenses in the 2014 Test Year of $126.1 million are $28.4 million higher than the 2007 Actual of $97.7 million. Costs in the 2015 Test Year of $138.2 million are $40.5 million higher than the 2007 Actual. Detailed explanations of the increases in costs are outlined in the following sections.

Salaries and Benefits

As indicated in Table 2.3, the 2014 Test Year salaries and benefits expense of $78.0 million is $19.7 million higher than the 2007 Actual costs of $58.3 million. The 2015 Test Year costs of $85.8 million are $27.5 million higher than the 2007 Actual. A further breakdown of the changes in salaries and benefits by cost type is shown in Table 2.4 and an explanation of the major changes follows.

Table 2.4

Salary and Benefit Expenses ($millions)						
Cost Type	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Salaries	49.5	66.6	73.2	23.7	77.9	28.4
Overtime	6.2	12.3	12.2	6.0	10.1	3.9
Gross Salaries	55.7	78.9	85.4	29.7	88.0	32.3
Capital Labour Costs	(11.3)	(20.2)	(22.0)	(10.7)	(22.6)	(11.3)
Total Salaries	44.4	58.7	63.4	19.0	65.4	21.0
Fringe Benefits	6.5	8.4	8.8	2.4	12.5	6.1
Employee Future Benefits	5.9	6.8	6.8	0.9	8.4	2.5
Group Insurance	2.2	2.4	2.5	0.3	2.6	0.4
Total Benefits	14.5	17.6	18.1	3.6	23.5	9.0
Total Salaries and Benefits, before cost recoveries	58.9	76.3	81.5	22.6	88.9	30.0
Cost Recoveries	(0.6)	(3.0)	(3.5)	(2.9)	(3.1)	(2.5)
Total Salaries and Benefits, net of Cost Recoveries	**58.3**	**73.3**	**78.0**	**19.7**	**85.8**	**27.5**

Salaries

As shown in Table 2.4, the 2014 Test Year salary costs of $73.2 million are $23.7 million higher than the 2007 Actual of $49.5 million. The primary drivers of this increase include cost of living salary adjustments of $16.8 million. Changes in FTEs also contributed to cost increases. In the 2014 Test Year, there are 861 operating FTEs[10] in Hydro, an increase of 44 FTEs over the 2007 Actual of 817. This results in additional costs of $6.0 million.

Costs in the 2015 Test Year of $77.9 million are $28.4 million higher than 2007 Actual. The primary drivers of this increase include cost of living increases of $20.2 million. In the 2015 Test Year, there are 895 operating FTEs, an increase of 78 FTEs over the 2007 Actual resulting in additional salary costs of $8.6 million.

[10] Operating FTEs are FTEs before any capital labour recharges.

Hydro also reports net FTEs[11], as outlined in Section 3.7.3 of the evidence which includes operating FTEs and FTEs who charge to capital. In the 2014 Test Year, net FTEs are 860, a decrease of one from the operating FTEs of 861. In the 2015 Test Year, net FTEs are 888, a decrease of 7 from the operating FTEs of 895.

Further details of the changes in salaries and FTEs by functional area are discussed in Section 2.4.2.

As discussed in Section 1 of the evidence, there is a tightening labour market in the Province, which has resulted in changes to the compensation packages offered to Hydro employees. Furthermore, during union negotiations in 2010, it was recognized that there were differentials in the wages offered by Hydro compared to NP and other Atlantic Canadian utilities, primarily due to Government's prior wage restraints, which also applied to Hydro. In order to attract and retain a qualified workforce, Hydro has provided wage and benefit increases over the 2007 to 2015 period, enabling Hydro to be competitive with market.

Since 2007, Hydro has negotiated two union agreements which have resulted in general salary increases and a number of hourly rate increases. The first negotiated union agreement resulted in increases of 3.0% effective April 1, 2007, 2008, and 2009 for each year and 6.5% effective April 1, 2010. The second resulted in increases of 4.0% on April 1, 2011, 2012, and 2013. Non-union personnel also received similar wage and benefit increases. Adjustments were also made to front line supervisor's wage rates, to maintain wage differentials between them and their direct reports. The agreement expired on March 31, 2014 and is currently being negotiated.

[11] Net FTEs are operating FTEs plus or minus operating and capital labour recharges from and to other Nalcor lines of business.

See Regulated Activities Section 2.3.5 for additional discussion on workforce management and salaries.

Overtime

Annual overtime costs are necessary to provide least cost reliable service. Overtime varies based on circumstances such as emergencies, which may arise due to weather and equipment related outages, labour shortages and capital project requirements. Overtime is also necessary at times to minimize customer outages or to minimize customer service interruption risks. Overtime also occurs as a result of compensation paid to shift workers who must work statutory holidays. Overtime is minimized where possible through work planning and promptly addressing vacancies.

The 2014 Test Year costs of $12.2 million are $6.0 million higher than the 2007 Actual costs of $6.2 million. In addition, the 2014 Test Year includes $5.4 million of capitalized overtime, an increase of $3.7 million over the 2007 Actual of $1.7 million. The net impact of these variances is an increase in operating overtime costs of $2.3 million. During 2014, overtime was driven by incremental work requirements identified as a result of the January outage as well as emergency call outs. The overall increase in capital overtime is primarily due to an increase in Hydro's capital program and higher salary costs over the period.

The 2015 Test Year costs of $10.1 million are $3.9 million higher than the 2007 Actual. In addition, the 2015 Test Year includes $5.2 million of capitalized overtime, an increase of $3.5 million over the 2007 Actual of $1.7 million. The net impact of these variances is an increase in overtime costs of $0.4 million. Overtime of $10.1 million in the 2015 Test Year is $2.1 million less than the 2014 Test Year of $12.2 million. This reduction in overtime is primarily a result of the additional FTEs. Additional information by functional area is presented in Section 2.4.2.

Capital Labour Costs

As noted previously, internal labour and overtime costs associated with Hydro's capital projects are capitalized. Table 2.5 shows the breakdown of capital labour costs.

Table 2.5

Capital Labour ($millions)

Cost Type	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007A Change	2015 Test Year	2015TY - 2007A Change
Capital Labour	(7.6)	(14.5)	(16.6)	(9.0)	(17.4)	(9.8)
Capital Overtime	(1.7)	(5.7)	(5.4)	(3.7)	(5.2)	(3.5)
Overhead Allocation	(2.0)	-	-	2.0	-	2.0
Total Capital Labour	**(11.3)**	**(20.2)**	**(22.0)**	**(10.7)**	**(22.6)**	**(11.3)**

The 2014 Test Year capitalized costs of $22.0 million are $10.7 million higher than the 2007 Actual capital labour recharges of $11.3 million. The increases in capital labour are primarily attributable to an increase in Hydro's capital program which has more than doubled since 2007, coupled with salary and benefit increases. This is partially mitigated by the discontinuation of the allocation of overhead to capital labour in 2012, as approved in Board Order No. P.U. 2(2012).

Capitalized labour in the 2015 Test Year of $22.6 million is $11.3 million higher than the 2007 Actual. The increase in capitalization is related to salary increases as well as growth in the capital program discussed previously.

Fringe Benefits

Fringe benefits include Canada Pension Plan (CPP), Employment Insurance (EI), Public Service Pension Plan (PSPP), and Workers Compensation premiums and contributions paid by Hydro. The $8.8 million of fringe benefits included in the 2014 Test Year is $2.4 million more than 2007 Actual costs of $6.4 million, mainly due to increased premiums for EI and CPP and increased contributions to the Public Service Pension Plan (PSPP) in combination with salary increases previously described in this Section. The 2015 Test Year costs of $12.5 million are $6.1 million higher than the 2007 Actual. Costs increases have been consistent with the increases in 2014 as well as an estimated $2.5 million additional expense associated with PPSP reform[12].

Employee Future Benefits

Employee future benefit (EFB) costs relate to severance payments upon retirement and health benefits provided to retirees on a cost-shared basis. These costs are forecasted using actuarial methods and include assumptions as to future benefit costs and interest rate expectations. The EFB costs of $6.8 million, included in the 2014 Test Year, are $0.9 million higher than the 2007 Actual costs of $5.9 million. This increase is primarily due to increases in current service costs and is partially mitigated by the exclusion of actuarial losses in the 2014 Test Year expense in accordance with Order P.U. 13(2012). In the 2015 Test Year, there is an increase of $2.5 million over the 2007 Actual for total costs of $8.4 million. This increase includes actuarial losses of $1.6 million. This is a proposed change from the accounting treatment outlined in Board Order P.U. 13 (2012) and is described in further details in Section 3.9.2.

Group Insurance

Group insurance benefits provide Hydro employees with health, dental, life insurance and accidental death and dismemberment coverage. Insurance costs for the 2014 Test Year of $2.5 million are $0.3 million higher than the 2007 Actual cost of $2.2 million. This increase is mainly due to higher employee salaries and associated life insurance premiums and self-insured experience claim increases for health and dental insurance. The 2015 Test Year costs of $2.6 million are $0.4 million higher than the 2007 Actual consistent with the reasons noted for the 2014 Test Year.

[12] In September 2014, the Government announced changes to the Public Service Pension Plan that resulted in increased employer contributions.

Cost Recoveries

As shown in Table 2.4, cost recoveries related to salaries and benefits for the 2014 Test Year of $3.5 million are $2.9 million higher when compared to the 2007 Actual cost recoveries of $0.6 million. In 2007, Hydro recovered salary and benefit costs mainly from CF(L)Co. Subsequent to 2007, additional salary and benefit costs were recovered from other Nalcor lines of business through the Administration fee (Admin fee), primarily related to Safety and Health, Human Resources, Information Systems, and Supply Chain services. Cost recoveries also include $0.3 million in labour costs associated with the CDM program that are deferred as outlined in Section 3.8.2 of this evidence. Cost recoveries for the 2015 Test Year are $3.1 million which is a slight decrease from the 2014 level of recoveries.

System Equipment Maintenance (SEM)

As shown in Table 2.3, costs of $22.4 million in the 2014 Test Year are $0.7 million less than the 2007 Actual cost of $23.1 million. The primary reasons are an increase in costs in TRO of $3.2 million as described in Section 2.4.2, more than offset by a cost decrease of $3.9 million in Generation as described in Section 2.4.2.

The 2015 Test Year costs of $26.3 million are $3.2 million higher than the 2007 Actual. The primary drivers of the increase relate to the additional costs in TRO of $7.3 million which are further outlined in Section 2.4.2 offset by a reduction in SEM costs in Generation of $4.1 million as described in Section 2.4.2.

Other Operating Expenses

As shown in Table 2.3, Other Operating Expenses included in the 2014 Test Year of $29.6 million are $10.4 million higher than the 2007 Actual costs of $19.2 million. The 2015 Test Year costs of $28.6 million are $9.4 million higher than the 2007 Actual. A breakdown of the changes in other operating expenses is shown in Table 2.6 and an explanation of the major changes follows.

Table 2.6

Other Operating Expenses ($millions)						
Cost Type	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY - 2007A Change**	**2015 Test Year**	**2015TY - 2007A Change**
Professional Services	3.8	4.3	10.6	6.8	8.4	4.6
Miscellaneous	4.2	4.7	5.2	1.0	5.2	1.0
Travel	2.9	3.2	3.6	0.7	3.6	0.7
Equipment Rentals	1.1	1.8	1.8	0.7	3.0	1.9
Insurance	1.7	2.4	2.7	1.0	2.6	0.9
Transportation	2.0	2.1	2.4	0.4	2.2	0.2
Office Supplies	2.3	2.2	2.2	(0.1)	2.5	0.2
Building Rental	1.2	1.1	1.1	(0.1)	1.1	(0.1)
Total Other Operating Expenses	**19.2**	**21.8**	**29.6**	**10.4**	**28.6**	**9.4**

Professional Services

As shown in Table 2.6, professional services have increased by $6.8 million from $3.8 million in 2007 Actual costs to $10.6 million in the 2014 Test Year. The 2015 Test Year costs of $8.4 million are $4.6 million higher than the 2007 Actual. A detailed breakdown of professional services is provided in Table 2.7.

Table 2.7

Professional Services ($millions)						
Cost Type	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Consultants	2.2	3.2	7.2	5.0	5.6	3.4
GRA and Board Related Costs	0.6	1.2	3.5	2.9	2.3	1.7
Software Costs	1.0	1.3	1.4	0.4	1.5	0.5
Audit and Legal	0.1	0.2	0.1	-	0.1	-
Cost Recoveries	(0.1)	(1.6)	(1.6)	(1.5)	(1.1)	(1.0)
Total Professional Services	**3.8**	**4.3**	**10.6**	**6.8**	**8.4**	**4.6**

The increase of $6.8 million in the 2014 Test Year over the 2007 Actual is primarily due to:

- Higher consulting costs of $5.0 million primarily due to costs associated with the Outage Inquiry of $2.0 million, CDM programs of $0.9 million (offset in cost recoveries), $0.9 million associated with environmental work and safety and health related programs, $0.7 million in condition assessments, $0.3 million in engineering related initiatives and $0.3 million in environmental remediation at Sunnyside Terminal Station;
- GRA and Board related costs of $2.9 million associated with an increased volume of applications and regulatory activity;
- Software costs have increased by $0.4 million, primarily due to vendor price increases and additional software programs; and
- An increase of $1.5 million in cost recoveries, primarily related to the deferral of CDM costs of $0.9 million and $0.7 million recovered from the Admin fee.

The increase of $4.6 million in the 2015 Test Year over the 2007 Actual is primarily due to:

- Consulting costs increased by $3.4 million primarily due to regulatory studies and filings of $1.0 million, $0.9 million associated with environmental work and safety and health related programs, $0.7 million in condition assessments, CDM programs of 0.3 million (offset in cost recoveries) and $0.3 million in engineering related activities;
- GRA and Board related costs increased by $1.7 million associated with an increased volume of applications and regulatory activity. The variance includes $0.3 million in amortization of hearing related costs which is $0.1 million higher than the amortization of hearing costs in 2007. Hearing related costs and deferrals are detailed in Section 3.4.2.
- Software costs have increased by $0.5 million, primarily due to vendor price increases and additional software programs; and

- Cost recoveries increased by $1.0 million primarily related to $0.7 million recovered through the Admin fee and $0.3 million related to the deferral of CDM costs.

Miscellaneous Expenses

Miscellaneous costs include training, payroll and municipal taxes. The 2014 Test Year costs of $5.2 million are $1.0 million higher than 2007 Actual. This is mainly attributable to higher municipal and employer payroll taxes of $0.9 million and an increase of $0.1 million in other costs. The 2015 Test Year costs of $5.2 million are on par with the 2014 Test Year levels.

Travel

Travel costs of $3.6 million in the 2014 Test Year are $0.7 million higher than 2007 Actual of $2.9 million. This increase is primarily related to increased travel fares. The 2015 Test Year costs of $3.6 million are on par with the levels in the 2014 Test Year.

Equipment Rentals

Equipment rental costs are comprised of telecommunication costs, equipment rentals, computer bandwidth costs as well as costs associated with the lease of black start diesel units at Holyrood. The 2014 Test Year equipment rental net cost of $1.8 million is $0.7 million higher than the 2007 Actual costs of $1.1 million of which, $0.4 million is recovered from third parties. The 2015 Test Year costs of $3.0 million are $1.9 million higher than the 2007 Actual. One of the primary drivers of this increase also relates to costs associated with the black start diesel units in Holyrood. The total cost of the lease from January 2014 to June 30, 2015 is $5.2 million. Hydro has proposed to defer and amortize these costs over a five year period beginning in 2015. The net amortization expense in 2015 is $1.0 million. Please refer to Section 3.4.2 for additional information regarding deferrals.

Insurance Costs

Insurance costs, which cover property/boiler and machinery, liability and excess, directors' and officers' liability, brokerage fees and other miscellaneous insurances, have increased by $1.0 million from the 2007 Actual costs of $1.7 million to the 2014 Test Year amount of $2.7 million. This increase is primarily a result of property coverage due to loss ratio, overall value increase and industry rate increase. The 2015 Test Year costs of $2.6 million are $0.9 million higher than the 2007 Actual primarily for the reasons previously mentioned.

Other Cost Recoveries

Other cost recoveries as outlined in Table 2.3, includes recoveries from external parties and from the provision of generation supply to Labrador industrial, a portion of which is non-regulated. The 2014 Test Year recoveries of $3.9 million are $1.0 million higher than the 2007 Actual recoveries of $2.9 million. This increase is mainly attributable to $ $1.1 million in recoveries of depreciation and interest costs from other Nalcor lines of business through the Admin fee. These increased cost recoveries are offset by a reduction of $0.8 million in recoveries from Labrador Industrial customer generation supply. The recoveries in the 2015 Test Year of $2.5 million are $0.4 million lower than the 2007 Actual. The primary driver for the increase in recoveries is $0.7 million from the Admin fee for depreciation and interest offset by a decrease of $1.3 million from Labrador Industrial Generation supply.

2.4.2 Operating Expenses by Functional Area

The major functional areas are Operations and Corporate Services as shown in Schedule 1 of this evidence. Within Operations, costs are grouped into Transmissions and Rural Operations (TRO), Generation, and System Operations and Planning. Corporate Services includes Leadership and Associates, Human Resources and Organizational Effectiveness (HROE), Finance, Project Execution and Technical Services (PETS) and Corporate Relations.

Table 2.8 shows the total operating expenses for the 2014 and 2015 Test Years in comparison to the 2007 Actual.

Table 2.8

Operations and Corporate Services Operating Expenses Net of Cost Recoveries ($millions)						
Operations	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Generation (Thermal & Hydraulic)	32.1	32.2	34.5	2.4	37.3	5.2
Systems Operations and Planning	3.0	3.7	3.6	0.6	5.8	2.8
Transmission and Rural Operations (TRO)	34.5	48.2	51.8	17.3	57.0	22.5
Total Operations	**69.6**	**84.1**	**89.9**	**20.3**	**100.1**	**30.5**
Corporate Services	28.1	27.7	36.2	8.1	38.1	10.0
Total Operating Expenses	**97.7**	**111.8**	**126.1**	**28.4**	**138.2**	**40.5**

Operations

Transmission and Rural Operations (TRO)

TRO has responsibility for providing safe, reliable service to customers through the Application of sound practices on asset management of transmission and distribution systems and associated high voltage terminal stations, 21 isolated diesel systems, diesel units at Hawkes Bay, St. Anthony and Happy Valley-Goose Bay, four gas turbines including the new combustion turbine, the telecommunications network and the mobile fleet.

A summary of operating expenses by cost category for TRO is noted in Table 2.9.

Table 2.9

Transmission and Rural Operations Operating Expenses ($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY vs. 2007A Change	2015 Test Year	2015TY vs. 2007A Change
Salaries and Benefits	20.8	31.6	33.5	12.7	34.9	14.1
SEM Expenses	7.5	9.7	10.7	3.2	14.8	7.3
Other Operating Costs	6.4	7.7	8.7	2.3	7.9	1.5
Cost Recoveries	(0.2)	(0.8)	(1.1)	(0.9)	(0.6)	(0.4)
Total Operating Expenses	**34.5**	**48.2**	**51.8**	**17.3**	**57.0**	**22.5**

Operating expenses in the 2014 Test Year for TRO of $51.8 million have increased $17.3 million from 2007 Actual costs of $34.5 million. The 2015 Test Year costs of $57.0 million are $22.5 million higher than 2007 Actual costs. The details of the increase are discussed in the following sections.

Salaries and Benefits

Salaries and benefits in the 2014 Test Year of $33.5 million are $12.7 million higher than the 2007 Actual of $20.8 million. In 2007, there were 309 operating FTEs compared to 343 in the 2014 Test Year, an increase of 34 FTEs. This increase includes a transfer of 8 employees formerly grouped with the Finance department, related to warehousing as well as wage increases since 2007. The additional FTEs are associated with increased maintenance activity and growing capital work due to aging terminal station equipment as well as initiatives undertaken to improve reliability. Additional staff includes protection and control technologists in 2014 to sustain completion of critical power system maintenance and one safety and health resource to sustain and improve safety performance in the Northern and Labrador regions.

The main components of the salary and benefits increases are:

- Salary increases of $6.7 million;
- $3.5 million increase in costs associated with changes in FTEs;
- $2.1 million increase in costs related to employee benefits;
- $1.9 million in net[13] overtime costs; and
- Partially offset by an increase of $2.5 million in capitalized labour which reduces the above noted increases.

Salaries and benefits in the 2015 Test Year of $34.9 million are $14.1 million higher than the 2007 Actual of $20.8 million. In the 2015 Test Year there are 350 operating FTEs, an increase of 41 over 2007 Actual. The new FTEs, beyond those in 2014, are required to sustain full completion of the annual preventative maintenance program, to enhance planning and scheduling driven by increased capital support, to provide improved maintenance efficiency, to enhance financial governance, to meet increased requirements due to customer growth in Labrador and to operate and maintain the new CT at Holyrood. The main components of the salary and benefits increases are:

- Salary increases of $8.0 million;
- Increases in costs of $4.1 million associated with new FTEs;
- An increase of $2.7 million in costs primarily related to public service pension reform;
- An increase of $1.2 million of costs associated with employee future benefits;
- An increase of $0.5 million in net overtime costs;
- Partially offset by an additional $2.8 million charged to capital jobs.

System Equipment Maintenance

System Equipment Maintenance expenses in the 2014 Test Year of $10.7 million are $3.2 million higher than the 2007 Actual of $7.5 million. The primary drivers of the

[13] Net of time charged to capital due to implementation of enhanced maintenance practices and to address emergency call outs.

increase are vegetation management of $1.4 million and $1.8 million related to improving transmission and distribution reliability performance and maintenance work. This increase is primarily related to the completion of preventative and corrective maintenance backlog[14] work associated with critical power transformers, air blast circuit breakers and protection and control systems. This work effort contributes to improved reliability of key assets in the transmission system and as a result enhanced service to customers.

System Equipment Maintenance expenses in the 2015 Test Year of $14.8 million are $7.3 million higher than the 2007 Actual of $7.5 million. In 2015, there is a further increase of $4.1 million from 2014 primarily related to:

- Costs of $1.0 million associated with the new CT and an additional $1.6 million to provide for the extended (two year) warranty to cover the provision of technical oversight and coaching from the Engineering, Procurement and Construction contractor related to the operation and maintenance of the unit;
- An increase of $2.8 million related to the maintenance of transmission assets in Labrador which are associated with the transmission lines and terminal stations from Churchill Falls to Wabush that were previously incurred by TwinCo;
- A further increase of $0.5 million related to vegetation management;
- Costs associated with the continuation of the work associated with preventative and corrective maintenance backlog reduction initiatives of $1.0 million are anticipated to be incurred in 2015. As these costs are not considered to be reflective of normal operating costs, Hydro has proposed a deferral of these costs with a five year amortization period beginning in

[14] Backlogs are a collection of maintenance work which is approved to be completed in future and is dependent on planned system outages for completion. In 2009, Hydro identified a six-year plan to bring large power transformer and breaker preventative maintenance in line with a six year cycle. This has resulted in an increase in SEM through the use of contractors.

2015. The 2015 Test Year includes $0.2 million of related amortization. The deferral of costs is discussed in greater detail in Section 3.4.2; and
- A reduction of $0.7 million in maintenance related costs associated with the incremental corrective and preventative backlog work completed 2014.

Other Operating Expenses

This category of costs includes all other operating costs associated with the activity in TRO. The 2014 Test Year costs of $8.7 million are $2.3 million higher than the 2007 Actual of $6.4 million. The primary drivers of the increase are:

- Consulting related costs of $0.7 million associated with condition assessments to provide information to determine appropriate maintenance strategies and timing of equipment replacements to ensure sustained reliable service;
- Telecommunications equipment costs associated with mobile radio rentals of $0.7 million. This is partially offset by cost recovery of $0.4 million for a net increase of $0.3 million.
- Aircraft rental expenses of $0.5 million due to higher rental rates; and
- Travel related costs of $0.4 million associated with inflationary impacts on travel costs.

The 2015 Test Year costs of $7.9 million are $0.8 million less than the 2014 Test Year. They reflect a return to a more normal level of activity and costs related to consulting, travel and transportation costs upon completion of increased maintenance of breakers and transformers. These costs were required to bring all breaker and transformer maintenance to the established frequency and remove this preventative maintenance from the year end maintenance backlogs.

<u>*Cost Recoveries*</u>

The TRO cost recoveries forecast has increased by $0.9 million from $0.2 million in 2007 to $1.1 million in 2014 largely due to third party cost sharing of mobile radio equipment. The 2015 Test Year recoveries of $0.6 million are on par with the 2014 Test Year recoveries.

Generation

Hydro's two primary sources of electricity generation on the Island Interconnected System are thermal and hydraulic. These generating plants are operated and maintained by two separate departments, Thermal Generation (Holyrood) and Hydro Generation (hydraulic generation) and the costs are reported separately. These departments ensure the safe, efficient and reliable delivery of electricity to the grid as required to meet customer demands.

Changes in operating expenses from 2007 Actual costs to 2014 and 2015 Test Years are shown in Table 2.10.

Table 2.10

Generation Operating Expenses ($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007A Change	2015 Test Year	2015TY - 2007A Change
Thermal Generation						
Salaries and Benefits	9.2	12.3	13.1	3.9	14.6	5.4
SEM Expenses	12.3	8.1	8.2	(4.1)	8.2	(4.1)
Other Operating Expenses	1.5	0.8	1.3	(0.2)	2.2	0.7
Thermal Generation	**23.0**	**21.2**	**22.6**	**(0.4)**	**25.0**	**2.0**
Hydraulic Generation						
Salaries and Benefits	6.6	8.5	8.7	2.1	9.3	2.7
SEM Expenses	1.7	1.5	1.9	0.2	1.7	-
Other Operating Expenses	0.8	1.0	1.3	0.5	1.3	0.5
Hydraulic Generation	**9.1**	**11.0**	**11.9**	**2.8**	**12.3**	**3.2**
Total Operating Expenses	**32.1**	**32.2**	**34.5**	**2.4**	**37.3**	**5.2**

Total Generation operating expenses have increased by $2.4 million from 2007 Actual costs to the 2014 Test Year and $5.2 million in the 2015 Test Year primarily due to the following:

Salaries and Benefits

Salaries and benefits of $21.8 million in the 2014 Test Year are $6.0 million higher than 2007 Actual costs of $15.8 million. In the 2014 Test Year, there are 195 operating FTEs, an increase of 16 over the 2007 Actual FTEs of 179. In Hydro Generation, from 2007 to 2014, there was an increase in FTEs primarily due to asset growth and associated support as well as an increase of two FTEs from the transfer of warehouse personnel from Finance. In Thermal, there was an increase in FTEs over this period, including the addition of on-site emergency response personnel as well as seven FTEs relating to the transfer of warehouse personnel from Finance. Cost increases are primarily due to:

- Salary increases of $4.1 million;
- An increase of $1.1 million associated with changes in FTEs;
- An increase of $1.4 million in employee benefits;
- Partially offset by an increase in the amount of labour capitalized of $1.1 million.

Salaries and benefits of $23.9 million in the 2015 Test Year are $8.1 million higher than 2007 Actual costs of $15.8 million. In the 2015 Test Year, there are 208 FTEs, an increase of 29 over the 2007 Actual. Cost increases are primarily due to:

- Salary increases of $4.9 million;
- An increase of $2.2 million associated with changes in FTEs;
- An increase of $1.3 million in fringe benefits primarily associated with PPSP reform;
- An increase in other employee benefits of $1.1 million; and
- Partially offset by a $1.0 million increase in the amount of labour capitalized.

The additional FTEs in 2015 have been added to address increasing maintenance requirements due to the aging assets, particularly at Holyrood, and to improve scheduling in light of the increased capital and maintenance activities.

System Equipment and Maintenance

SEM costs in the 2014 Test Year of $10.1 million are $3.9 million less than the 2007 Actual of $14.0 million. The primary reasons for the reduction in costs relates to the completion of amortization of costs associated with extraordinary repairs and expenses in Holyrood as follows:

- A reduction of $2.1 million associated with the amortization of the Asbestos Abatement program and the amortization of costs associated with Unit 2 boiler repairs at Holyrood included in 2007 but have since been fully amortized; and
- A reduction in SEM overhaul expenses from the 2007 Actual costs due to capitalization of major overhauls as approved by the Board in Order No. P.U. 2(2012).

SEM costs in the 2015 Test Year of $9.9 million are $4.1 million less than the 2007 Actual of $14.0 million. The primary reasons for the reduction in costs relates to the completion of amortization of costs associated with extraordinary repairs and expenses in Holyrood as well as the discontinuation of overhauls costs as noted in the 2014 variance explanation above.

Other Operating Costs

Other operating costs of $2.6 million in the 2014 Test Year are $0.3 million higher than the 2007 Actual costs of $2.3 million. The primary driver of the cost increase relates to consulting costs of $0.2 million associated with operating projects and condition assessments of equipment to determine asset maintenance requirements and the timing of asset replacements to ensure ongoing reliable operation of the assets.

The 2015 Test Year costs in this category of $3.5 million are $1.2 million higher than the 2007 Actual. One of the primary drivers of this increase relates to costs associated with the black start mobile diesel units in Holyrood. The total cost of the lease from January 2014 to June 30, 2015 is $5.2 million. Hydro has proposed to defer and amortize this cost over a five year period beginning in 2015. The net amortization expense in 2015 is $1.0 million. Please refer to Section 3.4.2 for additional information regarding deferrals.

System Operations and Planning

System Operations, comprised of the Energy Control Centre (ECC) and engineering support, manages the dispatch of energy across the provincial electrical systems, both on the Island and in Labrador, to ensure safe, reliable and efficient delivery of power to customer delivery points. System Planning staff include engineers and economists responsible for establishing the additions and modifications to generation, transmission and distribution facilities required to economically meet forecast changes in customer electricity requirements while adhering to established reliability criteria.

Changes in System Operations and Planning operating expenses from the 2007 Actual costs to the 2014 and 2015 Test Years are noted in Table 2.11.

Table 2.11[15]

System Operations and Planning Operating Expenses
($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007A Change	2015 Test Year	2015TY - 2007A Change
Salaries and Benefits	2.6	3.5	3.3	0.7	4.7	2.1
SEM Expenses	0.1	-	-	(0.1)	-	(0.1)
Other Operating Costs	0.3	0.2	0.3	-	1.1	0.8
Total Operating Expenses	**3.0**	**3.7**	**3.6**	**0.6**	**5.8**	**2.8**

[15] In 2013, the System Planning group moved from Project Execution and Technical Services to Systems Operations and Planning. Costs in Table 2.11 have been restated for comparative purposes to include this group.

Operating Expenses in the 2014 Test Year have increased $0.6 million from the 2007 Actual and increased $2.8 million in the 2015 Test Year. The change in expenses is outlined below:

Salaries and Benefits

Salary and benefits expense in the 2014 Test Year of $3.3 million are $0.7 million higher than the 2007 Actual costs of $2.6 million primarily due to salary increases. In the 2014 Test Year, there are 27 operating FTEs, a decrease of two from the 2007 Actual of 29 FTEs.

The 2015 Test Year costs of $4.7 million have increased by $2.1 million over the 2007 Actual. In 2015, there is a total of 36 operating FTEs forecast, an increase of seven FTEs over the 2007 Actual. Additional staff is required to accommodate system growth and planning. Hydro's electrical system will be interconnected to the North American grid for the first time in 2017/2018 and the way the system is planned and operated, as well as its cost structure, will fundamentally change. Hydro will begin undertaking the work necessary to ensure it is prepared for these significant changes in order to successfully integrate a large new source of generation and transmission infrastructure into the current electrical system. While Hydro has included some costs related to this in its 2015 Test Year, the Board may want to consider the deferral of these costs for future recovery upon the in-service of the Labrador Island Link. Salary costs associated with the new positions are $1.0 million and $1.0 million associated with normal salary increases. In addition, there is an increase of $0.4 million associated with employee benefits, primarily related to PPSP reform.

Other Operating Costs

Other operating costs in the 2014 Test Year of $0.3 million are on par with the 2007 Actual. In the 2015 Test Year, there is an increase of $0.8 million from the 2007 Actual.

This increase is primarily related to consulting costs associated with system planning studies related to the integration of additional generation sources.

Corporate Services

Changes in Corporate Services Operating Expenses by cost category from 2007 Actual costs to the 2014 and 2015 Test Years are shown in Table 2.12.

Table 2.12[16]

Corporate Services Operating Expenses ($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007A Change	2015 Test Year	2015TY - 2007A Change
Salaries and Benefits	19.7	20.4	22.9	3.2	25.4	5.7
SEM Expenses	1.9	2.7	2.1	0.2	2.1	0.2
Other Operating Costs	10.4	14.9	21.6	11.2	18.4	8.0
Cost Recoveries	(3.9)	(10.3)	(10.4)	(6.5)	(7.8)	(3.9)
Total Operating Expenses	**28.1**	**27.7**	**36.2**	**8.1**	**38.1**	**10.0**

2014 Test Year operating expenses of $36.2 million are $8.1 million higher than 2007 Actual costs. The 2015 Test Year costs of $38.1 million are $10.0 million higher than 2007 Actual. A further explanation by cost category and department follows.

<u>*Salaries and Benefits*</u>

Salaries and benefits expense in the 2014 Test Year in Corporate Services has increased by $3.2 million over 2007 Actual costs. Costs in the 2015 Test Year of $25.4 million are $5.7 million higher than the 2007 Actual. The change by department is shown in Table 2.13.

[16] In 2013, the System Planning group moved from Project Execution and Technical Services to Systems Operations and Planning. Costs in Table 2.12 have been restated for comparative purposes to include this group.

Table 2.13[17]

Corporate Services Salaries & Benefits ($millions)						
Cost Category	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Executive Leadership	2.2	1.1	1.7	(0.5)	1.6	(0.6)
HROE	3.9	5.0	5.6	1.7	6.3	2.4
Finance	7.4	8.6	9.5	2.1	10.3	2.9
Project Execution and Technical Services	3.7	2.2	2.4	(1.3)	3.0	(0.7)
Corporate Relations	2.5	3.5	3.7	1.2	4.2	1.7
Total Operating Expenses	**19.7**	**20.4**	**22.9**	**3.2**	**25.4**	**5.7**

Leadership and Associates

Leadership and Associates is comprised of Executive, General Counsel/Corporate Secretary, and Internal Audit. Salaries and benefits expenses in the 2014 Test Year for the Executive Leadership group is forecast to decrease by $0.5 million from the 2007 Actual costs of $2.2 million. In 2014, there is a total of 7 operating FTEs forecasted, a decrease of 7 FTEs from the 2007 Actual of 14 FTEs. This decrease is primarily due to a net reduction in FTEs and the associated salaries and benefits transferred to Nalcor during the period.

The 2015 Test Year costs of $1.6 million are $0.6 million lower than the 2007 Actual. This reflects the transfer of FTEs to Nalcor for a total of 6 operating FTEs in the 2015 Test Year.

Human Resources and Organizational Effectiveness

Salaries and benefits expense for HROE in the 2014 Test Year of $5.6 million is $1.7 million higher than the 2007 Actual costs of $3.9 million. In 2014, there are a total of 76 operating FTEs, an increase of 16 over the 60 FTEs in the 2007 Actual. These FTEs

[17] In 2013, the System Planning group moved from Project Execution and Technical Services to Systems Operations and Planning. Costs in Table 2.13 have been restated for comparative purposes to include this group.

include apprentices who charge time by region based on work activity. Cost increases are due to normal salary increases of $1.2 million and the addition of FTEs of $0.6 million. This increase is partially offset by capitalized labour of $0.3 million, primarily due to apprentices.

Salaries and benefits expense for HROE in the 2015 Test Year of $6.3 million is $2.4 million higher than the 2007 Actual costs. In the 2015 Test Year there are 69 operating FTEs, an increase of nine over 2007 Actual. The primary drivers of the cost increase include salary and FTE increases. There was also an increase of $0.9 million associated with employee benefits including pension reform as well as changes in employee future benefits. Consistent with the 2014 Test Year, these costs increases were partially offset by capitalized labour of $0.3 million.

Finance

Salaries and benefits expense for Finance is forecast to increase by $2.1 million from the 2007 Actual costs of $7.4 million to the 2014 Test Year amount of $9.5 million. In the 2014 Test Year, there are 89 operating FTEs, a decrease of 29 over 2007 Actual of 118 FTEs. This decrease includes a transfer of warehouse personnel from Finance to operations as well as the transfer of positions to Nalcor. Over this time period, positions have been added in Hydro Finance as part of a re-organization and to address financial reporting requirements. The primary drivers of the salary and benefits increase include:

- Salary increases of $1.8 million;
- A decrease of $0.8 million associated with FTE changes; and
- An increase of $1.0 million due to the discontinuation of capitalizing salaries as per Board Order P.U. 2(2012).

The 2015 Test Year costs of $10.3 million are $2.9 million higher than the 2007 Actual. In the 2015 Test Year, there are 95 operating FTEs, a decrease of 23 from the 2007 Actual. This decrease includes the transfer of positions as noted previously as well as additional

FTEs resulting from the re-organization and to address regulatory and financial reporting requirements. In the 2015 Test Year, changes are as noted above and also include an additional $0.5 million associated with employee benefits.

Project Execution and Technical Services

Salaries and benefits expense in the 2014 Test Year of $2.4 million is $1.3 million less than the 2007 Actual. From 2007 to 2014 an additional 15 operating FTEs were hired for a total of 85 operating FTEs in the 2014 Test Year. This additional staffing is to address growth in the capital program for sustaining Hydro assets and to provide reliable service as the assets reach the end of their service lives. The FTE additions and salaries and benefits increases for all employees were more than offset by higher capitalization of labour charges of $4.5 million resulting from growth in the capital program since 2007.

The 2015 Test Year costs of $3.0 million are $0.7 million less than the 2007 Actual. In the 2015 Test Year, there is an increase of 19 operating FTEs over 2007 Actual for a total of 89 operating FTEs. The increased costs associated with the additional FTEs are more than offset by an increase in capitalized labour of $5.1 million. In addition, there is an increase of $1.0 million related to employee benefits primarily associated with PPSP reform.

Corporate Relations

Corporate Relations include Corporate Communications and Shareholder Relations, Customer Service, and Energy Efficiency. Salaries and benefits for Corporate Relations in the 2014 Test Year as noted in Table 2.13 of $3.7 million are $1.2 million higher than the 2007 Actual of $2.5 million. In the 2014 Test Year, there is no change in operating FTEs of 39 from the 2007 Actual. Over this time period, salary increases were $1.0 million.

The 2015 Test Year costs noted in Table 2.13 of $4.2 million are $1.7 million higher than the 2007 Actual. In 2015 there are 43 operating FTEs, an addition of 4 FTEs over the 2007 Actual. Normal salary increases over this time period contributed to the increase as well as an increase of $0.4 million associated with the additional FTEs. The change includes a reduction in FTEs through the implementation of Automatic Meter Reading through many areas of Hydro's rural services territory, the transfer of FTEs to Nalcor, offset by an increase in personnel associated with the Energy efficiency programs. As well, in 2015 there is an increase of $0.5 million related to employee benefits expenses due to public service pension plan reform and the inclusion of costs associated with employee future benefits.

System Equipment Maintenance

SEM costs related to Corporate Services as outlined in Table 2.12 in the 2014 Test Year of $2.1 million are $0.2 million higher than the 2007 Actual costs of $1.9 million, mainly due to an increase in material related costs in the Information Systems (IS) Department. This increase is partially offset by the Administration fee recovery as the IS department is a common service department. For additional information on the Administration fee, please refer to Section 3.7.4. Costs in the 2015 Test Year of $2.1 million are comparable to 2014 costs.

Other Operating Costs

Other operating costs related to Corporate Services as outlined in Table 2.12 are forecast to increase by $11.2 million from the Actual costs in 2007 of $10.4 million to $21.6 million in the 2014 Test Year. The primary drivers of this increase are:

- An increase in consulting costs of $3.2 million which consists of $2.0 million associated with the Outage Inquiry, an increase of $0.9 million associated with environmental work and safety and health related programs and $0.3 million in engineering related initiatives.

- An increase in regulatory related costs of $2.9 million primarily due to Hydro consultant costs related to the GRA and other regulated activities of $1.2 million, Board and intervener costs of $1.0 million, an increase in the Board Annual Assessment of $0.4 million and capital supplemental applications of $0.3 million;
- Program costs of $2.1 million associated with the CDM program. These costs have been deferred and are proposed to be amortized as outlined in Section 3.4.2 of this Amended Application;
- Increase in insurance premiums of $1.0 million primarily related to property coverage due to loss ratio, overall value increase and industry rate increase;
- An increase of $0.9 million related to payroll taxes; and
- An increase in software related costs of $0.5 million.

Costs in the 2015 Test Year of $18.4 million are $8.0 million higher than the 2007 Actual as outlined in Table 2.12. The primary drivers are:

- An increase in consulting costs of $2.5 million which is primarily due to an increase in regulatory studies and filings of $1.0 million, an increase of $0.9 million associated with environmental work and safety and health related programs and $0.2 million in engineering related initiatives;
- An increase of $1.7 million related to regulatory activity primarily due to consulting services related to the GRA and other regulated activities of $0.7 million, an increase in the Board Annual Assessment of $0.4 million, depreciation and other applications of $0.4 million;
- An increase of $1.1 million related to payroll taxes;
- An increase in insurance premiums of $0.9 million primarily related to property coverage due to loss ratio, overall value increase and industry rate increase;
- Software costs have increased by $0.5 million, primarily due to vendor price increases and additional software programs; and

- CDM costs increased by $0.5 million. These costs have been deferred and will be amortized as outlined in Section 3.4.2 of this Application.

Cost Recoveries

Cost recoveries for the 2014 Test Year of $10.4 million as shown in Table 2.12 have increased by $6.5 million from the 2007 Actual recoveries of $3.9 million. This is primarily attributable to Admin fee recoveries of $4.4 million from other Nalcor lines of business and the deferral of CDM costs of $2.4 million. The 2015 Test Year cost recoveries of $7.8 million are $3.9 million higher than 2007 Actual primarily due to Admin fee recoveries of $4.5 million and CDM program cost deferrals of $0.7 million partially offset by a reduction in recoveries of $1.3 million related to generation supply in Labrador.

2.5 LOAD FORECASTS AND NEW POWER SUPPLY

The 2014 and 2015 load forecasts used in this updated submission were prepared in the same manner as previous submissions to the Board. They reflect a combination of direct input from the IC and NP, and Hydro's analysis for the interconnected and isolated systems. The total load requirement is determined from an analysis of overall system losses and demand diversity.

2.5.1 Island Interconnected Load Forecast

The 2007 Test Year load forecast, along with the actual power and energy requirements from Hydro for the Island Interconnected System for 2007-2013, and the operating load forecasts for 2014 and 2015, are provided in Schedule II. Table 2.14 presents the annual changes in Hydro's electricity requirements for that period.

Table 2.14

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2015 Island Interconnected System (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	Change in 2014	Change in 2015	2015 Forecast
Newfoundland Power	4,925.8	34.0	148.2	(91.8)	301.3	41.8	246.4	357.1	(38.7)	5,924.1
Industrial Customers	930.2	(203.9)	(332.1)	(24.7)	(58.6)	98.7	(58.3)	82.1	188.0	621.4
Rural and Losses	588.4	19.3	3.1	6.0	41.4	13.5	28.9	(0.4)	(10.6)	689.6
Total Island Interconnected	6,444.4	(150.6)	(180.8)	(110.5)	284.1	154.0	217.0	438.8	138.7	7,235.1

In 2008, electricity requirements on the Island Interconnected System declined by 2.3% relative to the 2007 Test Year, primarily because of reduced consumption at CBPP. CBPP's No. 1 paper machine was shut down in November 2007. In 2009, there was a further decline in electrical requirements (2.9% relative to 2008) due to the closure of the Grand Falls newsprint mill in February 2009 and the shutdown of No. 4 paper machine at CBPP in March 2009. The load reduction for these ICs was partially offset by increased utility load in 2009. In 2010, there was a further decline in electricity requirements by 1.8% relative to 2009, primarily because of warmer weather patterns which reduced the requirements of NP's and Hydro's residential and general service customers (the Utility load).

In 2011, there was an increase in electricity requirements by 4.7% relative to 2010. This reflects a return to normal weather patterns and higher Utility load. The increase was partially offset by lower IC requirements, particularly at CBPP and North Atlantic Refining Limited (NARL).

The Vale terminal station was energized in June 2012, with first power taken by the customer in December 2012. It is anticipated that Vale will continue to increase its levels of demand and energy consumption until it reaches full production levels by the end of 2016. In 2012 there was an increase in Island Interconnected load requirements of 2.4% over 2011. This load growth reflects the level of Utility load requirements and increased industrial consumption at CBPP and NARL.

In October 2013, another IC, Praxair, began taking power from Hydro. Praxair will provide the oxygen requirements for the Vale nickel processing facility and it is expected to increase operations through to the end of 2014. In 2013, there was an increase in total Island Interconnected load requirements of 3.4% relative to 2012. This increase is primarily due to increased Utility load, partially offset by decreased Industrial requirements at CBPP and NARL.

For 2014, Hydro is forecasting a 6.6% increase in load requirements, relative to 2013. This is due to increased Utility requirements resulting from the colder temperatures and increased demand experienced during the winter/early spring period and the increased IC requirements at Vale and Praxair.

For 2015, Hydro is forecasting a 2.0% increase in load requirements, relative to 2014. This is due to increases in requirements at Vale and Praxair which is nearly offset by decreased Utility requirements, with the expected return to normal weather. Beginning in June 2015 it is expected that Teck Resources will no longer require power and energy from Hydro.

The Island Interconnected System's total electrical requirements in 2015 are expected to be 12.3% above the 2007 Test Year requirements primarily due to the Utility load increase which has been partially offset by an overall decrease in industrial loads.

Customer peak demand requirements exhibit the same general growth pattern as energy requirements with lower industrial peak demands and offsetting increases in utility requirements. Peak demand requirements for NP and Hydro Rural for 2015 reflect both weather normalization and expected growth.

2.5.2 Labrador Interconnected Load Forecast

The 2007 Test Year load forecast, the actual power and energy supplied to the Labrador Interconnected System by Hydro for 2007-2013, and the operating load forecasts for 2014 and 2015 are provided in Schedule III. Table 2.15 outlines the changes in Hydro's electricity delivery requirements for that period.[18]

Table 2.15

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2015 Labrador Interconnected System (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	Change in 2014	Change in 2015	2015 Forecast
Hydro Rural	505.5	(6.9)	4.6	(33.0)	60.5	14.8	29.4	55.0	58.2	688.1
CFB Goose Bay	77.4	(16.7)	(41.3)	37.0	(5.0)	(33.8)	(14.4)	5.5	1.5	10.2
IOC	312.5	24.7	(175.3)	141.0	(174.0)	51.3	20.4	(61.2)	8.8	148.2
Wabush Mines and Losses	115.6	(23.5)	(26.3)	15.4	(11.9)	6.5	4.0	(4.3)	(16.1)	59.4
Total Labrador Interconnected	1,011.0	(22.4)	(238.3)	160.4	(130.4)	38.8	39.4	(5.0)	52.5	906.0

Hydro's overall electricity supply for the Labrador Interconnected System in 2008 declined by 2.2% relative to the 2007 Test Year, primarily due to reduced secondary energy consumption at CFB Goose Bay and lower system losses. The overall decline in 2008 was partially offset by increased consumption at IOCC.

In 2009, the electricity supply declined sharply by 24.1% from the requirements in 2008 due to significantly reduced consumption at IOCC and lower secondary energy loads at CFB Goose Bay. IOCC experienced a lengthy shutdown in the summer of 2009 and reduced consumption for significant periods during the remainder of the year.

In 2010, the electricity supply increased over 2009 by 21.4%. This was primarily driven by loads that had increased again at IOCC and CFB Goose Bay. The overall increase was

[18] Schedule III and Table 2.15 present the actual and forecast requirements from the recall power only and do not include TwinCo requirements for industrial.

partially offset by lower Hydro Rural requirements. The Hydro Rural load, with a high concentration of electric space heating, declined due to warmer overall weather patterns in the area.

In 2011, the total electricity requirements for the system were 14.3% lower than in 2010. This decrease is primarily driven by significantly reduced consumption at IOCC, partially offset by a return to normal weather patterns which resulted in increased Hydro Rural requirements.

In 2012, Labrador Interconnected load requirements increased by 5.0% over 2011. This increase is primarily due to increased consumption levels at IOCC and increased Hydro Rural requirements, partially offset by less reliance on secondary energy by CFB Goose Bay during 2012. CFB Goose Bay's electric boilers have been in operation since the 1980s. The customer has advised that it has installed oil fired boilers as a primary source of energy.

In 2013, Labrador Interconnected load requirements increased by 4.8% over 2012. This increase is primarily due to a further increase in requirements at IOCC supplied by Hydro and increased Hydro Rural requirements, partially offset by lower energy consumption at CFB Goose Bay. This customer has advised that it intends to continue taking small amounts of secondary energy for its electric boilers through to mid-2018.

In 2014 there is forecast to be a modest decrease of 0.6% in Labrador Interconnected load requirements relative to 2013. This is due to a decline in IOCC requirements from Hydro which has been nearly offset by increased Hydro Rural requirements. In June 2014 arrangements were put in place that allowed IOCC to use the excess TwinCo demand and energy that became available as a result of the decline in Wabush Mines operations. This has, in turn, lowered the requirements for IOCC purchases from Hydro.

For 2015, Hydro is forecasting an overall increase in energy requirements of 6.1% relative to 2014. This is due to a further increase in Hydro Rural requirements.

For 2015, Hydro's load forecast for the Labrador Interconnected System has decreased 10.4% from the 2007 Test Year. This reflects lower requirements supplied by Hydro to IOCC which is partially offset by higher Hydro Rural requirements associated with normalized weather, community load growth and load associated with the addition of the Muskrat Falls construction site.

TwinCo Power

As indicated previously in Section 2.2.5 the TwinCo block of power is produced by CF(L)Co at the Churchill Falls Generating Station and delivered at a delivery point near Churchill Falls. It is a firm 225 MW, 100% capacity factor block of power and energy, resulting in 1,971 GWh. The long standing TwinCo power arrangements will expire at the end of 2014.

For 2015, Hydro's total load forecast for the Labrador Interconnected System has increased 1.7 TWh (165%) from the 2007 Test Year. This is due primarily to Hydro supplying the industrial energy requirements that had previously been supplied by TwinCo and higher Hydro Rural requirements associated with normalized weather, community load growth and the load associated with addition of the Muskrat Falls construction sites.

The following table provides an indication of the total industrial requirements (recall power and TwinCo) since 2007, including the forecast for 2015.

Table 2.16

Summary of Total IOCC and Wabush Mines Electricity Requirements GWh

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast(1)	2015 Forecast
IOCC	1,520	1,726	1,398	1,680	1,458	1,544	1,549	n/a	1,720
Wabush Mines	420	412	365	399	390	380	339	n/a	70
Total Industrial Load	1,940	2,138	1,763	2,079	1,848	1,924	1,888	n/a	1,790

2.5.3 Isolated Diesel Systems Load Forecasts

The 2007 Test Year load forecast, the actual power and energy requirements for Hydro's isolated systems for 2007-2013, and the operating load forecasts for 2014 and 2015 are provided in Schedule IV. Table 2.17 presents the changes in Hydro's electricity requirements for that period.

Table 2.17

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2015 Isolated Diesel Systems (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	Change in 2014	Change in 2015	2015 Forecast
L'Anse Au Loup	16.9	1.6	1.9	0.5	2.4	(1.3)	2.1	0.6	0.3	25.0
Other Labrador Diesel	35.7	0.7	1.2	(0.3)	1.5	(0.6)	1.3	4.8	0.6	44.9
Island Diesel	8.6	0.1	0.2	(1.4)	0.4	(0.3)	0.2	(0.1)	(0.1)	7.6
Total Isolated	61.2	2.4	3.3	(1.2)	4.3	(2.2)	3.6	5.3	0.8	77.5

Electricity production across the Labrador Isolated diesel systems was higher in 2008 relative to the 2007 Test Year by 4.4%. There was a further increase of 5.6% in 2009 relative to 2008. The annual load increases are primarily driven by increased requirements in the L'Anse au Loup system caused by the construction of electrically heated homes and the conversion of existing homes to electric heat. The L'Anse au Loup system has experienced strong energy consumption growth as a result of a reduction in electricity rates upon the interconnection to Hydro-Québec's Lac Robertson system in 1996.

In 2007, the Government introduced an electricity rebate program[19] for domestic customers in isolated Labrador coastal communities, including the communities on the L'Anse au Loup system. The Labrador rebate reduces customer electricity costs on the first block of energy and basic customer charge to the equivalent of costs paid by customers on Labrador Interconnected Systems. In 2011, the total production requirements for the Labrador Isolated diesel systems were 6.6% higher than that experienced in 2010. In 2012, the requirements were 2.9% lower, relative to 2011. For 2013, requirements were 5.5% higher relative to 2012 primarily due to increased requirements for the L'Anse au Loup system. For 2014 Hydro is forecasting an increase of 8.5% in energy requirements relative to 2013. This is owing to the addition of several large general service accounts in communities along the north coast of Labrador, increased fish processing load and increased consumption for domestic customers. For the 2015, Hydro is forecasting a modest increase of 1.3% relative to 2014.

Hydro's load forecast for the Labrador Isolated diesel systems for 2015 has increased by 32.9% from the 2007 Test Year. This reflects the overall increased requirements in the L'Anse au Loup system and the underlying load growth trend for many of the other Labrador Isolated Systems.

Across the Island Isolated Systems, the load has not exhibited the same growth pattern as in the Labrador Isolated Systems. There was a 15.7% decline in 2010 relative to 2009. The decline in 2010 is partly due to milder weather during 2010 and no production at the fish plant in Little Bay Islands. The fish plant and associated services had an annual consumption of approximately one GWh.

In 2011, the total production requirements for the Island Isolated diesel systems were 4.6% higher than in 2010. In 2012 they were 3.2% lower, relative to 2011. In 2013 requirements were 2.3% higher relative to 2012, primarily due increased load in Ramea,

[19] Northern Strategic Plan.

mainly related to weather. The forecasts for 2014 and 2015 reflect a continued slow decline in the isolated communities.

2.5.4 New Power Supply

In order to ensure that the future capacity and energy requirements of the Island Interconnected System are met in a reliable and cost effective manner, Hydro regularly prepares long-term forecasts for the provincial power system and maintains a portfolio of projects with various levels of engineering feasibility.

The Company's assessment on the timing of the requirement for new investment for the Island Interconnected power supply and associated facilities is based on previously established generation planning criteria. These criteria set the minimum level for reserve capacity and firm energy to ensure an adequate power supply to meet the grid's firm load requirements. These criteria are:

- Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system energy capability; and
- Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a LOLH[20] expectation target of not more than 2.8 hours per year.

To ensure that the future capacity and energy requirements are met for the Labrador Interconnected System, the Industrial firm requirements are compared with the 225 MW block of TwinCo power, with the remaining requirements (additional Industrial and the Hydro Rural) compared with the 300 MW block of recalled power and associated energy, all available from CF(L)Co.

[20] Loss of Load Hours is a standard reliability measure in the utility industry.

Island Interconnected System

Table 2.18 presents the long-term planning load forecast and energy balances for the Island Interconnected System through to 2018. The load forecast reflects the longer-term view for the economy and incorporates the expected Utility load growth and the ramp up and sustained operation of the Vale nickel processing facility.

Table 2.18

Island Interconnected System
Load Forecast and Energy Balances
(GWh)

		Existing System	
Year	**Load Forecast**	**Firm Capability**	**Energy Balance**
2014	8,416	8,940	524
2015	8,549	8,940	391
2016	8,829	8,940	111
2017	8,924	8,940	16
2018	9,011	8,940	-71

Note: Firm energy reflects system as of August 2014 and does not include energy capability of installed combustion turbines.

The system firm energy capability[21] has been increased by 119 GWh since the 2007 Test Year to reflect the firm output of the two wind farms (167 GWh), partially offset by a reduction at the CBPP Co-Generation unit (48 GWh). Production at this unit has been reduced in recent years due to the reduction of operations at the CBPP mill and the resultant decrease in process steam requirements. The firm energy capability of the system does not include energy capability on installed gas turbines. Future supply requirements, including the negative energy balance in 2018 will be offset by the Muskrat Falls hydroelectric plant and the Labrador Island Link coming in-service in 2017-2018.

[21] Refer to Exhibit 3 of this Application for the breakdown of firm energy capability.

As outlined in Exhibit 3, the generating capacity of the Island Interconnected System is 2,050 MW. For calculations that involve unit capacity, it has been recognized that the nameplate capacity of the unit may need some adjustment to best reflect the actual usable capacity of the system, especially during peak periods. Thus, Hydro is now using the gross continuous unit ratings, where applicable. Nameplate ratings for generating units are taken from manufacturer design data and information supplied from non-utility or customer owned generators. These ratings generally represent the maximum continuous power-generating capacity of a generating unit. The gross continuous unit ratings for Hydro's units are generally reflective of the nameplate ratings but may be adjusted due to known permanent limitations or unavailability. For Hydro purchases and customer owned generation, gross continuous unit ratings reflect the output that is assumed during peak times and may be adjusted to account for available prime mover supply (i.e. wind, water or steam) or load restriction.

The existing system capacity has been adjusted to reflect the following:

- The capacity values provided in 2014 by NP for their generating units;
- Rating adjustments, a removal from service, and an addition to Hydro's gas turbine fleet; and
- The addition of capacity assistance arrangements with CBPP.[22]

There has been a total increase in NP's capacity of 3.9 MW which results from an increase in hydraulic generation of 5.9 MW and a decrease in diesel generation of 2.0 MW. Since the 2007 Test Year, the capacity of each of the gas turbines at Hardwoods and Stephenville has been reviewed and has been adjusted down by 4 MW for a total of 8 MW and the 10 MW gas turbine at Holyrood has been removed from service. A new 123 MW combustion turbine is planned to be in-service at Holyrood in December 2014.

[22] At the time of calculating the total Island Interconnected System generating capacity for this Amended GRA, discussions with Vale were very preliminary. Therefore, the proposed capacity assistance of 15.8 MW from this IC has not been included.

Hydro is proposing capacity assistance arrangements of 60 MW with CBPP for the upcoming winter period and potentially another 15 .8 MW from Vale.

Labrador Interconnected System

Hydro supplies the firm and secondary load requirements of the Labrador Interconnected grid with its purchased 300 MW recall block from CF(L)Co. Energy available from recall that is surplus to the requirements on the Labrador Interconnected System is exported from the Province. The energy requirements forecast for Hydro's recall power supply to the Labrador Interconnected grid through to the year 2018 is shown in Table 2.19.

Table 2.19

Labrador Interconnected System
Energy Forecast and Available Surplus
(GWh)

Year	Forecast	Recall	Surplus
2014	854	2,416	1,562
2015	906	2,416	1,510
2016	920	2,416	1,496
2017	1,090	2,416	1,326
2018	1,172	2,416	1,244

Note: Forecast, recall and surplus reflect energy volumes at Churchill Falls.

The load forecast includes the requirements of Hydro's rural retail customers, CFB Goose Bay secondary load and the share of Labrador west mining operations load which is more than that is available to these large industrial operations through the former TwinCo block. Under the existing load growth forecast, the 300 MW recall capability will satisfy the firm and secondary requirements of the Labrador Interconnected well beyond 2018.

Changes in Island Interconnected System Reserve and Newfoundland Power Generation Credit

"Reserve at" criteria is calculated to determine NP's generation credit. Reserve at criteria is not the same as system reserve. To calculate the reserve at criteria, the peak demand (while maintaining the forecast load factor for the year in question) is adjusted until the LOLH for the system becomes 2.80 (Hydro's criteria). Using this "demand at" criteria and the net capacity (Gross Continuous Unit Rating) of the system, the percent reserve at criteria is calculated. The reserve at criteria of the Island Interconnected System has changed, from 15.0% to 13.3%. When applied to NP's revised generation capability forecast for 2015, the generation credit becomes 119.33 MW. The calculation of NP's generation credit is shown in Table 2.20.

Table 2.20

NP Generation Credit (kW)	
Hydraulic Capacity	94,200
Thermal Capacity	41,000
Total	135,200
Reserve at Criteria	1.133
NP Generation Credit	119,329

Corner Brook Pulp and Paper Demand Credit Contract

In April 2009, the Board issued Order No. P.U. 17(2009) approving, on a pilot basis for a two-year period, a demand credit rate structure to be applied to Hydro's service agreement for CBPP. This service agreement format was intended to provide a price signal that would facilitate more efficient use of that customer's hydraulic generating resources in coordination with its pulp and paper mill operations.

In June and December 2011, Hydro completed assessments of the demand credit rate structure for the CBPP Service Agreement and determined that it provides hydraulic energy production efficiencies that permit lower energy production from Holyrood. The rate structure achieves these energy savings by providing an incentive for CBPP to operate its hydraulic generation resources in a manner which provides more efficient energy production rather than have CBPP maintain power production at levels that avoid incurring additional capacity charges. Reports with Hydro's findings were submitted to the Board requesting that the pilot agreement be permanently put in place.

In subsequent Order Nos. P.U. 15(2011) and P.U. 4(2012), the Board approved extensions of the service agreement on a continued pilot basis until a further Order of the Board. Contained in Exhibit 4 of this Application, is an updated request for approval of the service agreement with the following considerations as outlined by the Board:

> *…analysis in relation to potential and actual fuel savings at Holyrood, the efficiency factor at the Holyrood Thermal Generating Station, the Rate Stabilization Plan, and the allocation of costs in revenue requirement*.

With this Application, Hydro is recommending that the pilot agreement be made permanent.

2.6 ENERGY SUPPLY EXPENSES

2.6.1 Island Interconnected System

The actual energy supply sources and fuel expenses for 2007-2013 and the forecast for the 2014 and 2015 are summarized in Schedule V.

Hydraulic Production Forecast

Hydraulic production for 2015 is forecast to be 4,603.6 GWh. This is the average expected production for 2015 using the methodology consistent with that previously approved by the Board and further described in Section 2.7.

Energy Purchases and Related Costs

Energy purchases in 2007 and 2008 were above the 2007 Test Year forecast of 415 GWh by 39 GWh and 36 GWh, respectively. The increase in 2007 was primarily due to higher secondary energy receipts from the ACI generation. In 2008, the increase was primarily attributable to increased production from the Exploits River Hydro Partnership and the start of commercial production in September of 2008 at the wind farm at St. Lawrence. In 2009, 2010, 2011, 2012 and 2013 energy purchases and receipts were above the 2007 forecast by 567 GWh, 534 GWh 490 GWh, 579 GWh, and 597 GWh respectively. This is primarily due to Exploits Generation that was previously used in the Grand Falls paper mill and the production from the St. Lawrence and Fermeuse wind farms, the latter of which started operation in April of 2009. The high levels of energy purchases and receipts in 2009 to 2013 were partially offset by decreased production at the CBPP co-generation unit. Generation from this unit has been reduced due to the shutdown of two of the four paper machines and the resulting decrease in process steam available to drive the co-generation unit. For 2014, the energy purchases are forecast to be 603 GWh above the 2007 Test Year forecast, due to the same factors mentioned previously.

The forecast energy purchases for 2015 are 1,031 GWh, which is based on Hydro's hydraulic generation model (VISTA) output for the Exploits Generation, the historical average data for Rattle Brook and design estimates for the wind farms. This is 616 GWh higher than the 2007 Test Year forecast. The 2015 forecast generation for the CBPP co-generation unit has been reduced from the 2007 Test Year to reflect experience since the shutdown of the paper machines. The purchase costs from all sources in 2015 are forecast to increase to $57.4 million from $33.5 million in 2007 Actual costs. This overall increase results from the inclusion of the wind projects and purchase of the Exploits Generation which has been partially offset by lower production levels at the CBPP co-generation unit. The 2015 costs also include the total fixed fees ($2.1 million) associated with the Capacity Assistance arrangements with CBPP and Vale for the 2014/2015 winter period.

The suppliers and related expenses for power purchases are presented in Schedule VI. Holyrood meets the energy supply requirements beyond Hydro's hydraulic production and energy purchases. The primary factors affecting the plant's fuel expenses are its production level, fuel to energy conversion rate and fuel purchase price. These factors for 2007 to 2015 are included in Schedule V.

Holyrood Energy Production and Related Costs

Energy production from Holyrood in 2007 and 2008 was 1,256 GWh and 1,080 GWh, respectively. In 2009 and 2010, production levels were at 940 GWh and 803 GWh, respectively. In 2011 and 2012, the output levels from the station were 885 GWh and 856 GWh, respectively. In 2013, the output level from the Holyrood generating station was 957 GWh. The forecasts for 2014 and the 2015 Test Year are 1,373 GWh and 1,593 GWh, respectively. The changes from the 2007 Test Year are due to load, power purchases and hydraulic production variances.

The actual fuel conversion factors for 2007 and 2008 were 614 kWh/bbl and 625 kWh/bbl, respectively. In 2009 and 2010, the conversion performance was 612 kWh/bbl and 589 kWh/bbl, respectively. In 2011 and 2012, the performances were 603 kWh/bbl and 599 kWh/bbl, respectively. The actual energy conversion factor for 2013 was 594 kWh/bbl. In 2014, the conversion performance is forecast to be 588 kWh/bbl.

The decline in fuel conversion performance in recent years is primarily due to changes external to the operation of the Holyrood thermal generating station and therefore cannot be affected by the manner in which the plant is operated. There have been lower production requirements at Holyrood as a result of reduced system loads, higher energy purchases and higher levels of hydraulic generation. All things being equal, a thermal unit operates most efficiently at higher levels of generation. Performance has also deteriorated due to a lower heating content in the fuel used at Holyrood since the switch to 0.7% sulfur content in 2009.

A change in the approach to forecasting Holyrood conversion rate is necessary in this updated GRA filing due to the financial impact incurred by Hydro resulting from the low conversion rate in recent years. Table 2.21 outlines the losses to Hydro since 2009.

Table 2.21

Holyrood Fuel Conversion Performance and Hydro Financial Impact
2009 - 2014

	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast
Fuel Consumption ('000 bbls)	1,534.7	1,363.2	1,469.2	1,428.3	1,611.0	2,334.5
Actual Fuel Conversion Rate (kWh/bbl)	612	589	603	599	594	588
2007 TY Fuel Conversion Rate (kWh/bbl)	630	630	630	630	630	630
Hydro's Financial Loss ($ million)	2.4	4.9	3.5	3.9	5.1	8.8

Under the current mechanism of the RSP, there is no provision for Hydro to recover the additional fuel consumption costs due to lower fuel conversion rate at the prevailing Test Year fuel price. Hydro is only able to recover the additional fuel costs related to additional consumption and any change from the Test Year fuel price.[23] Hydro will be presenting further evidence and a proposal regarding the stabilization of costs relating to the fuel conversion rate.[24]

The forecast conversion factor for the 2015 Test Year is 607 kWh/bbl. This forecast results from a five-year regression analysis of conversion factor versus Holyrood gross monthly average unit loading, adjusted for fuel heating content (in BTUs/bbl). There is a station service factor of 6.6% applied to the gross energy production. The station service factor is based on the average experience over the past five year period (June 2009 - May 2014). The improvement in conversion rate to 607 kWh/bbl above recent experience is due to anticipated higher production requirements and a reduction in

[23] The cost related to the additional consumption at the actual fuel price minus the Test Year fuel price.
[24] In Vale's Expert Report (April 25, 2014) and in subsequent RFI response to NLH-V-002, it was proposed that changes in Holyrood fuel conversion efficiency should be accounted for in the RSP.

minimum operating time which will be enabled by the new CT at Holyrood. This is obtained through higher levels of average output for the Holyrood units. However, improvements in the fuel heating content are not anticipated.

The actual average fuel purchase prices for 2007 to 2013 and forecasts for 2014 and 2015 are indicated in Table 2.22.

Table 2.22

Holyrood No. 6 Fuel ($/bbl)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast
Average No. 6 Fuel Purchase Price	56.86	70.23	55.11	75.74	96.72	115.26	105.58	106.46	90.85

The forecast prices assume 0.7% sulfur content. The detailed monthly actual and forecast purchase prices are provided in Schedule VII. The fuel prices for June to September 2014 are referenced to the June 2014 Corporate forecast which is based on the May 2014 forecast of PIRA Energy Group. The fuel prices for October 2014 to December 2015 are referenced to the October 2014 Corporate forecast which is based on the September 2014 forecast of PIRA Energy Group.

The actual total Holyrood fuel expense was $107.4 million in 2007 and is forecast to rise to $244.9 million in 2015, a 128% increase over the eight-year period and a 79% increase from the 2007 Test Year, primarily driven by the increasing purchase prices.

Standby Generation Requirements and Related Costs

For the winter periods of 2014/2015 and 2015/2016 there are peaking requirements assumed for the Island Interconnected System CTs in order to maintain minimum generation reserve requirements. The requirements for the CTs are determined based on average forced outage rates of 10% for the Holyrood thermal units and 1% for Hydro's hydraulic units, and in consideration of the peak load forecast and Hydro's typical load duration curve.

The Island Interconnected System gas turbine and diesel production also assumes that each plant is exercised at rated output for one hour per month during the non-winter period for testing and for ensuring availability. These units are assumed to be exercised for four hours during each winter month (approximately once per week) for winter readiness and storm preparedness.

The total energy forecasted to be produced at the Island Interconnected System gas turbine and diesel generating plants is 11.4 GWh for the 2015, at an associated fuel cost of $3.6 Million.

2.6.2 Labrador Interconnected System

The majority of all energy consumed on the Labrador Interconnected System is purchased from CF(L)Co. The only exception is when the gas turbine and diesel generation in Happy Valley-Goose Bay are operated for Labrador Interconnected System outages or system support. The actual power purchase costs from CF(L)Co ranged from $1.9 million to $2.4 million for each of the years from 2007 to 2013. The costs are forecast to be $2.1 million and $1.9 million for 2014 and the 2015, respectively.
The other power purchase expenses for the Labrador Interconnected System relate to the annual costs for Hydro's share of expenses related to TwinCo's Wabush Terminal Station. These expenses were $0.76 million in 2007 and $0.27 million in 2008. In 2009 costs were $0.35 million and $0.49 million in 2010. In 2011 the costs were $0.58 million, while in 2012 they were $0.40 million. In 2013 the costs were $0.21 million. Costs are forecast to be $0.71 million in 2014. The variability of these costs is caused by variances in the major maintenance and equipment replacements undertaken by CF(L)Co on behalf of TwinCo.

As indicated in Section 2.2.5, at the end of 2014 the long-standing TwinCo arrangements expire and, as such, no costs related the Wabush Terminal Station are included in Hydro's Labrador Interconnected System power purchase costs for the 2015 Test Year. The costs for this equipment will now be part of the station costs as outlined in Section 2.4.2.

2.6.3 Isolated Systems

The primary source of power supply for Hydro's isolated systems throughout the Province is diesel generation. The Company has also availed of opportunities to supplement or displace diesel generation. On the L'Anse au Loup system, the Company displaces diesel generated energy by purchasing secondary energy from a regional Hydro-Québec hydroelectric plant. On the Ramea diesel system, Hydro continues with its energy receipts from wind generation. On the Mary's Harbour diesel system, until 2007, Hydro purchased energy from an independent hydro generator; however, the plant was shut down in 2007 and is in need of refurbishment. Schedule VIII presents Hydro's 2007 Test Year budgets, the actual diesel fuel and purchased power expenses for its isolated systems for 2007 to 2013, along with the forecast expenses for 2014 and 2015. Diesel fuel and purchased power expenses have increased from $12.1 million in the 2007 Test Year to $19.7 million in 2013. This increase reflects higher electricity requirements for isolated systems and the prices for petroleum in world markets. In 2014, expenses are forecast to increase to $23.2 million, primarily due to increasing supply requirements but also due to higher fuel prices. For 2015, the Company's isolated systems fuel and purchased power costs are forecast at $21.9 million.

2.7 HYDROELECTRIC PRODUCTION FORECAST

2.7.1 Introduction

This section describes the methodology used by Hydro to estimate its average annual hydroelectric energy production in the 2015 Test Year.

For the 2004 Test Year, Hydro prepared the average annual energy production forecast for hydraulic generation facilities using the 30 years of inflows from 1973 to 2002. However, during the 2003 GRA, Hydro's consultant, Hatch (formerly SGE Acres), provided evidence to confirm that it would be better to use the full hydrological record (dating back to 1950) after certain inconsistencies in the record had been resolved. In addition, Hatch recommended the use of a simulation model (SYSSIM), rather than a spreadsheet, to prepare the estimate. Hydro worked with Hatch to make the required adjustments to the hydrological record and to select and implement the SYSSIM model. The average energy value provided for the 2007 Test Year was based on the revised record and the SYSSIM modeling.

In addition to its use in preparation of the 2006 GRA, Hydro used the SYSSIM model to estimate hydroelectric production for budgeting, fuel forecasting, and other planning activities. However, over time, the model seemed less able to accurately determine the contribution of the hydraulic resources compared to the required thermal production. The model still provided results, but changes to the input, for example adding new wind resources, did not have the anticipated effect on the hydroelectric and thermal production estimates. This problem seemed to have been caused, or at least worsened, by the decrease in industrial load as a result of the paper mill closures and paper machine shutdowns on the island.

In anticipation of this GRA, Hydro again retained Hatch to provide advice on how to proceed – whether changes were possible to improve the SYSSIM model of the Hydro system or whether a new methodology was required. Hatch's advice was to switch to the VISTA DSS model. A letter from Hatch, describing the evolution of their modeling techniques and outlining their recommended approach for use in the GRA is attached as Exhibit 5.

2.7.2 Vista DSS Model

Background

Hydro first implemented the Vista DSS in the 1990s. Initially, only the LT (long-term) Vista module was implemented; LT Vista provides guidance on optimized unit dispatch on a weekly time step. In the 2008-2009 period, Hydro implemented the ST (short-term) Vista module which provides more detailed optimized dispatch on an hourly time step. Part of the implementation of the ST module was to add inflow forecasting capability to the model. Currently, Hydro uses seven-day hourly precipitation and temperature forecasts to produce inflow forecasts for use in hourly modeling.

Use of Vista for GRA

When planning for the 2006 GRA, Hydro worked with Hatch to assess the best methodology for determining the average hydroelectric capability of its system. At that time, the use of Vista was considered, but not chosen. Since 2006, various changes as noted in Exhibit 5 have been made to Vista which makes it more suitable for use in studies and budget forecasts. In particular, in preparation for Hydro's use of Vista for this GRA, Hatch added a new option which allows a value to be assigned to water in storage at the end of the simulation period. This means target water levels do not have to be set and Vista can make more realistic decisions at the end of the simulation period.

2.7.3 System Assumptions

Hydrology

As per Board Order No. P.U. 14(2004), simulations for this updated GRA were completed using all available hydrology from 1950 through 2013 inclusive, 64 years in total.

Inflows to each of Hydro's reservoirs are calculated daily from measured water levels and estimated outflows. At the end of each year, Hydro reviews the calculated inflows and makes any necessary adjustments. Adjustments include:

- Smoothing to remove calculated negative inflows, a common problem when back calculating inflows from water level changes; and
- Adjustments to the distribution of inflows between two reservoirs when the estimates of flow in the connecting canals are not well known.

Inflow data for recent years was added according to the methodologies recommended by Hatch during the last GRA.

Exploits Generation

Hydro's Vista model has always included generating plants on the Exploits River but prior to 2010 the generation was modeled as one pseudo plant of 92 MW for the combined output of Buchans, Grand Falls and Bishop's Falls. Star Lake was modeled separately, but still in a simplified form.

In 2010, Hatch was asked to develop a more realistic and complete representation of the Exploits plants in the Vista model. The Vista model now has realistic representations of each watershed and power plant. The total forecast generation included for the Exploits generation in 2015 is 776 GWh, as shown previously in Table 2.1.

Newfoundland Power and Non-Utility Generators (NUGS)

All hydroelectric generation sites on the Island Interconnected System are modeled in Vista.

NP's sites are modeled as one pseudo site with characteristics and input hydrology that result in a reasonable estimate of its generation. Several other small plants (Snook's Arm, Venam's Bight, Rattle Brook, and Roddickton mini-hydro) are included with NP's sites as they are too small to warrant modelling separately and have similar characteristics to NP's sites.

Deer Lake Power's plant on Grand Lake is modeled to a level of detail similar to that of Hydro's own system.

Estimates of generation from each wind farm and from CBPP's co-generation plant are included in the model as purchase contracts.

Thermal Generation

Holyrood was modeled similarly to the previous Application. It has a minimum production level set for each week of the year, reflecting the requirements for meeting peak loads and transmission constraints.

2.7.4 Impact on the Hydraulic Production Forecast

The hydraulic production forecast determined from the Vista model and used for 2015 in this updated Application is 4,604 GWh compared with the final forecast used in the 2007 Test Year of 4,472 GWh. The changes are due to an extension in the record of inflows to incorporate the data up until 2013, improvements in methodology and enhanced representation of the non-Hydro owned hydroelectric generation sources. The increase in hydraulic production is also due to improved utilization of inflows during the wetter sequences which is facilitated by the higher load and reduced spill. The combined impact results in an increase in the annual average hydroelectric production estimate for 2015 of 132 GWh. It should be noted that Exploits Generation as described in Section 2.7.3 is included in power purchases as Hydro does not currently own these assets.

2.8 RURAL DEFICIT

Revenues from Hydro's Rural Customers, with the exception of those on the Labrador Interconnected System, do not fully recover the cost to serve, resulting in a deficit (Revenue Deficit). The Rural Deficit has grown from $40.8 million in the 2007 Test Year to a forecast of $64.1 million in the 2015 Test Year, primarily due to increased supply costs. Controllable costs, primarily operating expenses, remain relatively consistent from year to year, despite increasing wages, general inflationary pressure on material supply costs and other costs.

Hydro's mandate to provide least-cost, safe and reliable power to all its customers remains its primary focus. Hydro continues to control its operating expenses using measures such as the CDM program which is mandated to develop and implement demand and energy conservation programs both internally and externally for customers. Such efforts reduce Hydro's costs and assist in reducing and/or limiting growth in supply costs.

Other dedicated efforts which are aimed at controlling the Rural Deficit include operating and capital initiatives such as capturing waste heat, monitoring diesel system fuel efficiency, utilizing commercial air flights rather than helicopter use, use of fuel efficient mix of engines to supply load, more effective planning and scheduling to minimize outages and delays, life cycle cost analysis for diesel engines, automatic meter reading, install of in-line heaters at diesel plants, e-billing, and in-house printing of customer bills. Hydro will continue to undertake initiatives to manage its costs of serving its Rural Customers in a manner that is consistent in providing reliable service and in minimizing the Rural Deficit.

List of Schedules:

SCHEDULE I	OPERATING EXPENSES BY FUNCTIONAL AREA
SCHEDULE II	ACTUAL AND FORECAST ELECTRICITY REQUIREMENTS FOR 2007 TO 2015 - ISLAND INTERCONNECTED SYSTEM
SCHEDULE III	ACTUAL AND FORECAST ELECTRICITY REQUIREMENTS FOR 2007 TO 2015 - LABRADOR INTERCONNECTED SYSTEM
SCHEDULE IV	ACTUAL AND FORECAST ELECTRICITY REQUIREMENTS FOR 2007 TO 2015 - ISOLATED SYSTEMS
SCHEDULE V	ENERGY SUPPLY AND FUEL EXPENSE FOR 2007 TO 2015 - ISLAND INTERCONNECTED SYSTEM
SCHEDULE VI	ENERGY PURCHASES BY SUPPLIER FOR 2007 TO 2015 - ISLAND INTERCONNECTED SYSTEM
SCHEDULE VII	MONTHLY NO. 6 FUEL PURCHASE PRICES FOR 2007 TO 2015
SCHEDULE VIII	ISOLATED FUEL AND PURCHASED POWER COSTS FOR 2007 TO 2015

Newfoundland and Labrador Hydro
Operating Expenses by Functional Area
($000's)

	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007 Actual Change	2015 Test Year	2015TY - 2007 Actual Change
Operations						
Thermal Generation	20,870	21,220	22,644	1,774	23,984	3,114
Deferred Major Extraordinary Repairs	2,109	-	-	(2,109)	-	(2,109)
Deferred Regulatory Costs	-	-	-	-	1,044	1,044
Hydro Generation	9,112	10,959	11,871	2,759	12,438	3,326
Generation	32,091	32,179	34,515	2,424	37,466	5,375
System Operations and Planning[1]	2,920	3,753	3,604	684	5,765	2,845
Deferred Regulatory Costs	50	-	-	(50)	-	(50)
System Operations and Planning	2,970	3,753	3,604	634	5,765	2,795
Transmission & Rural Operations	34,541	48,210	51,756	17,215	56,660	22,119
Deferred Major Extraordinary Repairs	-	-	-	-	249	249
Transmission & Rural Operations	34,541	48,210	51,756	17,215	56,909	22,368
Total Operations	69,602	84,142	89,875	20,273	100,140	30,538
Corporate Services						
Project Execution and Technical Services[1]	4,186	2,949	3,661	(525)	4,176	(10)
Deferred Regulatory Costs	61	-	-	(61)	-	(61)
Finance	11,908	11,753	17,561	5,653	16,881	4,973
Deferred Regulatory Costs	223	-	-	(223)	333	110
Allocation to non-regulated customer	(2,679)	(2,021)	(1,926)	753	(2,271)	408
Human Resources & Organizational Effectiveness	6,608	7,346	8,153	1,545	9,398	2,790
Leadership & Associates	2,762	1,534	2,031	(731)	1,986	(776)
Corporate Relations	5,022	6,109	6,713	1,691	7,536	2,514
Total Corporate Services	28,091	27,670	36,193	8,102	38,039	9,948
Operating Expenses	**97,693**	**111,812**	**126,068**	**28,375**	**138,179**	**40,486**

[1] Tables and certain numbers have been restated to reflect the transfer of Systems Planning Group formerly in Project Execution and Technical Services to Systems Planning.

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2015
Island Interconnected System

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Newfoundland Power	1,121.5	4,925.8	1,083.0	4,990.7	1,109.4	4,959.8	1,168.1	5,108.0	1,146.3	5,016.2	1,186.3	5,317.5	1,177.9	5,359.3	1,276.3	5,605.7	1,233.4	5,962.8	1,295.0	5,924.1
Hydro Rural Interconnected	84.8	392.0	79.9	400.0	88.9	411.7	87.5	415.3	81.7	406.5	95.5	437.6	88.8	445.6	95.8	458.0	95.4	467.5	95.2	463.9
Industrial Customers	126.9	930.2	135.8	816.2	106.1	726.3	104.6	394.2	65.7	369.5	61.9	310.9	64.7	409.6	64.1	351.3	79.0	433.4	81.5	621.4
Total Deliveries	1,307.6	6,248.0	1,258.4	6,206.9	1,264.0	6,097.8	1,332.7	5,917.5	1,245.2	5,792.2	1,329.0	6,066.0	1,313.3	6,214.5	1,410.0	6,415.0	1,382.5	6,863.7	1,448.3	7,009.4
Transmission Losses	39.9	196.4	64.6	182.1	59.0	196.0	57.3	195.5	59.8	210.3	69.8	220.6	71.9	226.1	90.8	242.6	48.4	232.7	50.7	225.7
Hydro Island Requirement	1,347.5	6,444.4	1,323.0	6,389.0	1,323.0	6,293.8	1,390.0	6,113.0	1,305.0	6,002.5	1,398.8	6,286.6	1,385.2	6,440.6	1,500.8	6,657.6	1,430.9	7,096.4	1,499.0	7,235.1

Notes:
1. The 2014 and 2015 Forecasts are sourced to the June 25, 2014 Island Operating Load Forecast.
2. Required NLH Net Generation MW's are NLH system coincident MW's and include customer firm demand requirements only. MWs in 2014 are December forecast values. MWs in 2015 are January
3. Demands for Total Deliveries and Transmission Losses are coincident with system peak. Actual transmission losses include station services.
4. Actuals reflect rounded values to the nearest tenth of a GWh.
5. Teck Resources is anticipated to cease operations in June 2015.
6. Industrial MW's for 2007-2013 reflect sum of annual maximum customer demands.

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2015
Labrador Interconnected System

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hydro Rural Interconnected																				
Happy Valley - Goose Bay	57.5	235.0	55.0	228.0	59.0	230.0	59.8	230.8	57.8	216.3	62.1	243.8	61.1	250.6	67.8	268.0	73.5	298.7	78.4	325.4
Churchill Falls	0.3	1.5		1.4		1.3		1.1		1.2		1.4		1.3		1.4	0.3	1.8	0.3	1.5
Wabush	15.1	62.0	15.7	63.8	17.6	66.1	17.5	67.6	16.1	62.7	17.5	72.8	18.0	77.4	21.7	83.4	20.5	93.4	22.6	100.0
Labrador City	50.6	207.0	49.0	201.5	49.0	201.2	51.5	203.7	48.5	190.0	50.8	212.7	50.5	216.2	53.5	222.1	51.7	236.0	58.7	261.2
Total	123.5	505.5	119.7	494.7	124.3	498.6	128.8	503.2	122.4	470.2	130.4	530.7	129.7	545.5	143.0	574.9	146.0	629.9	160.0	688.1
Department of National Defence	-	77.4	-	62.9	-	60.7	-	19.4	-	56.4	-	51.4	-	17.6	-	3.2	-	8.7	-	10.2
Iron Ore Company of Canada	82.0	312.5	88.8	257.1	95.4	337.2	82.6	161.9	90.8	302.9	83.2	128.9	63.4	180.2	84.9	200.6	76.6	139.4	57.0	148.2
Wabush Mines	-	0.2	-	0.2	-	0.2	-	0.1	-	0.1	-	0.1	-	0.1		-	-	-	4.0	6.0
Total Deliveries	170.4	895.6	162.4	814.9	173.9	896.7	165.0	684.6	171.0	829.6	182.1	711.1	182.6	743.4	194.6	778.7	204.8	778.0	195.4	852.6
Transmission Losses	21.6	115.4	22.3	75.0	25.8	91.9	44.1	65.7	24.2	81.1	39.7	69.2	21.3	75.7	27.2	79.8	25.8	75.5	24.6	53.4
Hydro Labrador Requirement	192.0	1,011.0	184.7	889.9	199.7	988.6	209.1	750.3	195.2	910.7	221.8	780.3	203.9	819.1	221.8	858.5	230.6	853.5	220.0	906.0

Notes:

1. The 2014 and 2015 Forecasts are sourced to the June 26, 2014 Labrador Operating Load Forecast.
2. Actual customer peaks are annual maximums. System peak excludes interruptible and secondary load. MWs in 2014 are December forecast values. MWs in 2015 are January forecast values.
3. Demands for Total Deliveries and Transmission Losses are coincident with system peak.
4. Sales to CFB Goose Bay and Wabush Mines are secondary sales.
5. Actuals reflect rounded values to the nearest tenth of a GWh.
6. In 2013 Happy Valley - Goose Bay includes the Muskrat Falls Contruction Site consumption (3.456 GWh).

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2015
Isolated Systems

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh
Labrador Isolated																				
Davis Inlet	1,468	6,629	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
L'Anse au Loup	3,740	16,884	3,974	17,556	4,451	18,495	4,463	20,363	4,688	20,912	4,931	23,292	5,043	22,049	5,756	24,073	5,669	24,661	5,736	24,953
Others	8,661	35,700	8,539	35,340	9,536	36,421	9,050	37,644	9,421	37,296	9,208	38,754	8,814	38,207	9,281	39,504	10,310	44,316	10,448	44,911
Total (excluding Davis Inlet)	12,401	52,584	12,513	52,896	13,987	54,916	13,513	58,007	14,109	58,208	14,139	62,046	13,857	60,256	15,037	63,577	15,979	68,977	16,184	69,864
Island Isolated	2,844	8,577	2,323	8,043	2,664	8,707	2,623	8,934	2,221	7,528	2,293	7,876	2,277	7,621	2,200	7,797	2,274	7,679	2,263	7,645
Total Isolated		61,161		60,939		63,623		66,941		65,736		69,922		67,877		71,374		76,656		77,509

Notes:
1. Forecast source is NLH Spring 2013 Rural Operating Load Forecast.
2. Peaks are non-coincident net annual maximums.
3. Net production excludes station services.
4. Operations ceased at Davis Inlet in early 2006, when the community moved to Natuashish.
5. Natuashish is operated by Hydro for the Department of Indian and Northern Affairs with full cost recovery.

Newfoundland and Labrador Hydro
Energy Supply and Fuel Expense for 2007 to 2015
Island Interconnected System

	2007 Test Year	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast
Total Energy Requirement (GWh)[3]	6,444.4	6,389.0	6,293.7	6,113.0	6,002.4	6,286.6	6,440.7	6,657.6	7,096.4	7,239.0
Hydraulic Production (GWh)	4,472.1	4,689.4	4,771.0	4,199.5	4,273.8	4,512.4	4,595.0	4,688.3	4,702.6	4,603.6
Energy Receipts and Purchases (GWh)[1][2][4]	414.9	453.9	450.6	981.6	948.4	905.3	994.2	1,012.3	1,017.8	1,031.0
Gas Turbine/Diesels Production (GWh)	3.0	(10.0)	(8.1)	(7.9)	(10.6)	(8.5)	(4.3)	(0.5)	3.0	11.4
Holyrood Production (GWh)	1,554.5	1,255.6	1,080.2	939.9	803.1	885.3	855.8	957.4	1,373.0	1,593.0
Holyrood No. 6 Fuel Conversion Factor (kWh/bbl)	630	614	625	612	589	603	599	594	588	607
Holyrood No. 6 Fuel Consumption (bbl)	2,467,396	2,044,648	1,728,681	1,534,707	1,363,179	1,469,169	1,428,337	1,610,966	2,334,546	2,624,371
Average No. 6 Fuel Purchase Price ($/bbl)	56.71	56.86	70.23	55.11	75.74	96.72	115.26	105.58	106.46	90.85
No. 6 Fuel Production Cost ($000)	136,867	107,369	123,734	80,585	100,674	135,136	164,001	171,786	255,841	244,913
Gas Turbine/Diesel Production Cost ($000)	528	420	1,370	840	1,120	687	596	1,255	6,417	3,561

Notes:
1. After February 12, 2009, data includes Nalcor Exploits base generation at Grand Falls, Bishop's Falls and Buchans originally used for Grand Falls paper mill operations.
2. Energy received from Nalcor Exploits base generation was stored, rather than purchased, prior to 2011.
3. Total energy requirements excludes transferred energy amounts transferred from Hydro to CBPP of 8.55 GWh, 12.30 GWh, and 30.34 GWh, in 2009, 2010 and 2011, respectively.
4. Total energy receipts and purchases excludes energy amounts transferred from CBPP to Hydro of 8.55 GWh and 22.36 GWh, in 2009 and 2011, respectively.

Newfoundland and Labrador Hydro
Energy Purchases by Suppliers for 2007 to 2015
Island Interconnected System

Supplier	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000
NP at Hydro Request	-	-	0.05	-	0.46	108	0.52	119	0.20	15	0.09	7	0.10	114	0.97	533	3.26	733	-	-
CBPP Secondary[1]	-	-	0.39	11	0.08	2	6.96	207	4.46	(74)	3.92	-	6.25	321	8.24	80	9.20	-	-	-
ACI-GF Secondary[2]	20.59	689	64.12	2,282	29.58	1,361	7.41	237	-	-	-	-	-	-	-	-	-	-	-	-
Star Lake[4]	142.45	10,432	147.79	10,813	147.69	10,940	148.50	10,255	135.83	11,232	129.82	5,193	144.45	5,778	140.61	5,624	144.99	5,893	142.18	5,687
Rattle Brook	14.59	1,128	11.91	913	13.69	1,131	15.59	1,202	17.42	1,380	18.66	1,490	14.63	1,181	14.76	1,229	13.70	1,127	15.00	1,254
Corner Brook Cogen	100.24	10,086	92.54	8,632	74.09	7,956	55.74	5,525	51.54	5,469	50.50	5,917	47.84	6,906	55.89	9,260	48.93	9,805	51.07	10,281
Exploits River Project	137.00	10,757	137.13	10,801	177.19	13,798	179.95	14,006	112.40	8,664	-	-	-	-	-	-	-	-	-	-
St. Lawrence Wind	-	-	-	-	7.82	536	100.64	7,248	100.46	7,072	110.00	7,777	103.84	7,383	96.38	6,876	99.54	7,117	104.80	7,514
St. Lawrence Wind Ecoenergy Incentive Credit[3]		-		-		-		(620)		(620)		(685)		(586)		(632)		(588)		(638)
Fermeuse Wind	-	-	-	-	-	-	53.74	4,443	82.80	6,255	87.96	6,674	91.20	6,952	95.52	7,313	81.72	6,268	84.41	6,488
Fermeuse Wind Ecoenergy Incentive Credit		-		-		-		(386)		(620)		(663)		(683)		(715)		(534)		(632)
Nalcor Grand Falls, Bishops Falls and Buchans[4]	-	-	-	-	-	-	-	-	-	-	510.63	20,425	585.90	23,436	599.73	23,989	611.94	24,384	633.50	25,340
CBPP Capacity Assistance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.21	80	7.71	6,126	-	1,680
Vale Capacity Assistance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	442
Total Power Purchases	414.87	33,092	453.93	33,452	450.60	35,832	569.05	42,236	505.11	38,773	911.58	46,135	994.21	50,802	1,012.31	53,637	1,020.99	60,331	1,030.96	57,416

Notes:
1. Adjustment required in 2010 to account for June, 2009 metering issue
2. ACI-GF secondary ceased on February 12, 2009
3. Ecoenergy Incentive Credits are paid to Hydro quarterly at $0.0075/kwh on the eligible production (up to a maximum of 82.78 GWh annually)
4. Energy purchased from Nalcor generation at Grand Falls, Bishop's Falls, Buchans and Star Lake in 2011, 2012, 2013 2014, and 2015 is at $0.04/kWh.

Newfoundland and Labrador Hydro
Monthly No. 6 Fuel Purchase Prices for 2007 to 2015
($/bbl)

	2007		2008	2009	2010	2011	2012	2013	2014	2015
	Forecast	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Forecast(1)(2)	Forecast
January	56.40	43.65	73.98	45.52	75.99	82.71	110.99	103.39	111.97	92.00
February	55.25	46.81	71.41	45.80	72.73	92.02	116.71	112.64	118.69	90.10
March	57.35	48.63	72.43	46.75	72.53	102.20	127.24		120.93	91.70
April	55.95						120.63	100.96	117.53	92.90
May	54.50	57.10							110.59	91.50
June	53.75		104.86						112.80	93.00
July	52.85	56.23							114.40	90.90
August	53.10	57.56							118.00	92.90
September	52.70								116.40	92.70
October	54.65					107.03			93.20	94.00
November	57.35	71.44	49.01	78.66	79.27	114.70	103.46	105.89	92.30	90.80
December	60.65	73.43	43.30	74.75	82.74			103.89	90.00	88.80
Weighted Purchase Price	56.71	56.86	70.23	55.11	75.74	96.72	115.26	105.58	106.46	90.85

Notes:
1. There were no purchases in months with a blank.
2. In 2014 actual fuel purchase prices are indicated to the end of May.

Newfoundland and Labrador Hydro
Isolated Fuel and Purchased Power Costs for 2007 to 2015
($000)

	2007 Test Year	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast
Diesel Fuel										
Davis Inlet	1,564									
Other Hydro Diesel	10,391	10,340	14,937	12,522	12,266	15,642	15,791	16,430	19,667	18,592
Total (excluding Davis Inlet)	10,391	10,340	14,937	12,522	12,266	15,642	15,791	16,430	19,667	18,592
Purchased Power										
L'Anse au Loup	1,567	1,586	2,254	1,643	2,054	2,890	2,931	3,056	3,329	3,055
Ramea	121	60	101	94	114	108	296	221	221	232
Mary's Harbour	44	18	-	-	-	-	-	-	-	-
Total	1,732	1,664	2,355	1,737	2,168	2,998	3,227	3,277	3,550	3,287
Total	**12,123**	**12,004**	**17,292**	**14,259**	**14,434**	**18,640**	**19,018**	**19,707**	**23,216**	**21,879**

Notes:
1. L'Anse Au Loup fuel purchases include deferred fuel savings.
2. 2014 and 2015 Forecast sourced to October 2014 Isolated Fuel and Power Purchase budgets.