Newfoundland Power Inc.

Operating Costs by Function
2013 to 2017F
($000s)

	Function	Actual 2013	Actual 2014	Actual 2015	Forecast 2016	Forecast 2017
1	Distribution	9,226	8,994	8,903	9,026	9,291
2	Transmission	928	1,289	1,034	1,041	1,065
3	Substations	2,629	2,627	2,646	2,725	2,805
4	Power Produced	2,877	2,985	2,808	3,026	3,111
5	Administrative & Engineering Support	6,866	8,248	7,375	7,673	7,897
6	Telecommunications	1,418	1,552	1,409	1,351	1,378
7	Environment	243	210	238	290	299
8	Fleet Operations & Maintenance	1,885	1,912	1,778	1,705	1,593
9						
10	**Electricity Supply**	**26,072**	**27,817**	**26,191**	**26,837**	**27,439**
11						
12	Customer Services	9,458	9,750	8,843	9,337	9,107
13	Conservation	717	802	707	778	801
14	Uncollectible Bills	897	1,490	1,313	1,310	1,337
15						
16	**Customer Services**	**11,072**	**12,042**	**10,863**	**11,425**	**11,245**
17						
18	Information Systems	3,175	3,370	3,655	3,953	4,150
19	Financial Services	1,707	1,751	1,779	1,883	1,941
20	Corporate & Employee Services	13,243	13,400	13,852	14,259	13,940
21	Insurances	1,197	1,243	1,260	1,241	1,266
22						
23	**General**	**19,322**	**19,764**	**20,546**	**21,336**	**21,297**
24						
25	**Gross Operating Cost**	**56,466**	**59,623**	**57,600**	**59,598**	**59,981**

1st Revision Note: Updated for 2015 actuals and revised forecasts for 2016 and 2017.

Newfoundland Power Inc.

Operating Costs by Breakdown
2013 to 2017F
($000s)

		Actual 2013	Actual 2014	Actual 2015	Forecast 2016	Forecast 2017
1	Regular and standby	$ 28,735	$ 29,678	$ 29,700	$ 30,258	$ 31,242
2	Temporary	2,554	2,437	1,832	2,040	1,599
3	Overtime	2,615	3,394	2,409	2,817	2,908
4	**Total Labour**	**33,904**	**35,509**	**33,941**	**35,115**	**35,749**
5						
6	Vehicle Expenses	1,881	1,901	1,786	1,698	1,586
7	Operating Materials	1,568	1,841	1,580	1,641	1,674
8	Inter-Company Charges	53	41	35	50	50
9	Plants, Subs, System Oper & Bldgs	2,153	2,312	2,367	2,269	2,314
10	Travel	1,278	1,277	1,014	1,198	1,222
11	Tools and Clothing Allowance	1,141	1,191	1,130	1,133	1,155
12	Miscellaneous	1,476	1,430	1,381	1,387	1,418
13	Taxes and Assessments	1,011	1,040	1,123	1,150	1,173
14	Uncollectible Bills	897	1,490	1,313	1,310	1,337
15	Insurance	1,197	1,243	1,260	1,241	1,266
16	Severance & Other Employee Costs	84	58	72	73	74
17	Education, Training, Employee Fees	390	292	297	337	346
18	Trustee and Directors' Fees	397	431	462	467	476
19	Other Company Fees	1,820	2,222	2,506	2,689	2,053
20	Stationery & Copying	308	266	230	279	285
21	Equipment Rental/Maintenance	677	769	746	803	819
22	Telecommunications	1,622	1,710	1,621	1,586	1,617
23	Postage	1,452	1,508	1,562	1,553	1,584
24	Advertising	365	388	353	456	465
25	Vegetation Management	1,993	1,789	1,766	1,827	1,863
26	Computing Equipment & Software	799	915	1,055	1,336	1,455
27	**Total Other**	**22,562**	**24,114**	**23,659**	**24,483**	**24,232**
28						
29	**Gross Operating Cost**	**$ 56,466**	**$ 59,623**	**$ 57,600**	**$ 59,598**	**$ 59,981**

1st Revision Note: Updated for 2015 actuals and revised forecasts for 2016 and 2017.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Statements of Income
($000s)

		Actual			Forecast	
		2013	**2014**	**2015**	**2016E**	**2017E**
1	Revenue from rates	586,904	619,504	639,631	662,704	666,202
2	Excess earnings	(68)	-	-	-	-
3	Transfers from (to) the RSA	10,436	4,039	7,414	3,296	1,844
4		597,272	623,543	647,045	666,000	668,046
5						
6	Purchased power expense	392,928	404,550	424,430	449,647	451,206
7	Amortization of weather normalization reserve	(2,335)	(2,335)	(2,335)	-	-
8	Demand management incentive account adjustments	(383)	628	-	-	-
9		390,210	402,843	422,095	449,647	451,206
10						
11	Contribution	207,062	220,700	224,950	216,353	216,840
12						
13	Other revenue	7,445	5,570	5,206	4,842	4,770
14						
15	Other expenses:					
16	Operating expenses[1]	53,641	56,927	55,157	58,174	59,569
17	Employee future benefit costs	25,624	24,244	26,355	18,564	15,852
18	Deferred cost recoveries and amortizations	(768)	3,990	3,990	-	-
19	Depreciation	46,964	49,288	51,851	54,627	57,623
20	Finance charges	35,624	35,791	35,161	35,383	36,745
21		161,085	170,240	172,514	166,748	169,789
22						
23	Income Before Income Taxes	53,422	56,030	57,642	54,447	51,821
24	Income taxes[1]	14,866	16,201	16,529	15,777	15,127
25						
26	Net Income	38,556	39,829	41,113	38,670	36,694
27	Preferred Dividends	563	557	556	552	552
28						
29	Earnings applicable to Common Shares[1]	37,993	39,272	40,557	38,118	36,142
30						
31	**Rate of Return and Credit Metrics**					
32	Rate of Return on Rate Base (percentage)	8.10%	7.83%	7.48%	6.99%	6.65%
33	Regulated Return on Book Equity (percentage)	9.16%	9.15%	8.98%	8.03%	7.30%
34	Interest Coverage (times)	2.3	2.3	2.3	2.2	2.1
35	CFO Pre-W/C + Interest / Interest (times)	3.7	3.9	3.8	3.9	3.7
36	CFO Pre-W/C / Debt (percentage)	19.5%	18.6%	17.9%	18.2%	16.2%

[1] Shown after adjustment for non-regulated expenses.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Statements of Retained Earnings
($000s)

		Actual			Forecast	
		2013	**2014**	**2015**	**2016E**	**2017E**
1	Balance - Beginning	323,886	351,279	366,426	395,934	413,193
2	Net income for the period	49,920	37,840	39,314	36,548	34,405
3	Allocation of Part VI.1 tax	741	981	245	252	252
4		374,547	390,100	405,985	432,734	447,850
5						
6	Dividends					
7	Preference shares	563	557	556	552	552
8	Common shares	22,705	23,117	9,495	18,989	10,733
9		23,268	23,674	10,051	19,541	11,285
10	Balance - End of Period	351,279	366,426	395,934	413,193	436,565

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Balance Sheets
($000s)

	Actual			Forecast	
	2013	**2014**	**2015**	**2016E**	**2017E**
Assets					
Current assets					
Cash	$ 159	$ -	$ -	$ -	$ -
Accounts receivable	90,499	82,073	80,600	89,311	95,051
Income taxes receivable	1,391	3,593	9,105	-	-
Materials and supplies	1,228	1,315	1,435	1,447	1,476
Prepaid expenses	1,080	1,315	1,304	1,315	1,341
Regulatory assets	31,891	29,726	14,545	16,810	13,021
	126,248	118,022	106,989	108,883	110,889
Property, plant and equipment	914,948	984,268	1,038,108	1,083,262	1,148,953
Intangible assets	15,412	16,064	18,264	21,457	23,115
Regulatory assets	340,359	327,793	330,814	322,309	318,919
Defined benefit pension plans	-	-	-	-	3,254
Other assets	1,874	1,284	1,301	1,188	1,160
	$ 1,398,841	$ 1,447,431	$ 1,495,476	$ 1,537,099	$ 1,606,290
Liabilities and Shareholders' Equity					
Current Liabilities					
Short-term borrowings	$ -	$ 3,843	$ 2,404	$ -	$ -
Accounts payable and accrued charges	81,905	80,443	80,719	89,869	88,233
Interest payable	7,786	6,444	7,246	7,115	6,925
Defined benefit pension plans	248	244	239	233	228
Other post employment benefits	3,239	2,695	2,971	3,377	3,667
Regulatory liabilities	2,335	2,335	-	-	-
Current installments of long-term debt	34,453	70,000	53,750	(1,646)	44,119
	129,966	166,004	147,329	98,948	143,172
Regulatory liabilities	135,507	136,053	139,768	145,013	150,772
Defined benefit pension plans	6,366	14,706	6,643	1,862	-
Other post employment benefits	93,381	82,548	83,565	85,649	87,619
Other liabilities	840	660	1,286	700	700
Deferred income taxes	120,940	126,194	128,322	130,925	133,068
Long-term debt	481,260	475,571	513,369	581,549	575,134
Shareholders' Equity					
Common shares	70,321	70,321	70,321	70,321	70,321
Preference shares	8,981	8,948	8,939	8,939	8,939
Retained earnings	351,279	366,426	395,934	413,193	436,565
	430,581	445,695	475,194	492,453	515,825
	$ 1,398,841	$ 1,447,431	$ 1,495,476	$ 1,537,099	$ 1,606,290

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Statements of Cash Flows
($000s)

		Actual			Forecast	
		2013	2014	2015	2016E	2017E
1	**Cash From (Used In) Operating Activities**					
2	Net Earnings	$ 49,920	$ 37,840	$ 39,314	$ 36,548	$ 34,405
3						
4	**Items not affecting cash:**					
5	Amortization of property, plant and equipment	48,839	51,376	54,172	56,794	59,581
6	Amortization of intangible assets and other	2,763	2,760	2,790	3,111	3,554
7	Change in long-term regulatory assets and liabilities	6,973	7,618	(1,649)	5,174	2,309
8	Income tax liability	(12,814)	-	-	-	-
9	Deferred income taxes	(878)	(241)	(698)	2,603	2,143
10	Employee future benefits	(61)	(1,767)	4,832	3,978	556
11	Other	(204)	322	(318)	(230)	(238)
12		94,538	97,908	98,443	107,978	102,310
13						
14	Change in non-cash working capital	(3,754)	4,692	4,617	4,185	(6,169)
15		90,784	102,600	103,060	112,163	96,141
16						
17	**Investing Activities**					
18	Capital expenditures	(88,655)	(113,438)	(111,236)	(101,667)	(120,573)
19	Intangible asset expenditures	(3,134)	(3,158)	(4,748)	(6,123)	(5,028)
20	Contributions from customers and security deposits	2,727	3,687	2,508	5,450	1,550
21	Other	72	47	551	(473)	28
22		(88,990)	(112,862)	(112,925)	(102,813)	(124,023)
23						
24	**Financing Activities**					
25	Change in short-term borrowings	(685)	3,843	(1,439)	(2,404)	-
26	Net proceeds (repayment) of committed credit facility	(42,000)	64,500	(47,000)	(25,755)	45,767
27	Proceeds from long-term debt	70,000	-	75,000	75,000	-
28	Repayment of long-term debt	(5,200)	(34,453)	(6,250)	(36,250)	(6,600)
29	Proceeds from related party loan	33,000	240,000	35,500	-	-
30	Repayment of related party loan	(33,000)	(240,000)	(35,500)	-	-
31	Payment of debt financing costs	(382)	(80)	(386)	(400)	-
32	Redemption of preference shares	(100)	(33)	(9)	-	-
33	Dividends					
34	Preference Shares	(563)	(557)	(556)	(552)	(552)
35	Common Shares	(22,705)	(23,117)	(9,495)	(18,989)	(10,733)
36		(1,635)	10,103	9,865	(9,350)	27,882
37						
38	**Change in Cash**	159	(159)	-	-	-
39	**Cash (Bank Indebtedness), Beginning of Year**	-	159	-	-	-
40	**Cash (Bank Indebtedness), End of Year**	$ 159	$ -	$ -	$ -	$ -

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Average Rate Base[1]
($000s)

	Actual			Forecast	
	2013	**2014**	**2015**	**2016E**	**2017E**
Plant Investment	826,099	879,631	937,986	987,519	1,042,782
Additions to Rate Base					
Defined Benefit Pension Costs	100,636	102,549	101,384	96,802	94,045
Credit Facility Costs	120	36	64	48	32
Cost Recovery Deferral - Seasonal Rates	94	82	59	25	-
Cost Recovery Deferral - Hearing Costs	322	483	161	-	-
Cost Recovery Deferral - Regulatory Amortizations	2,767	1,661	554	-	-
Cost Recovery Deferral - 2012 Cost of Capital	1,472	883	294	-	-
Cost Recovery Deferral - 2013 Revenue Shortfall	1,126	1,689	563	-	-
Cost Recovery Deferral - Conservation	1,156	3,511	6,200	8,893	11,991
Customer Finance Programs	1,405	1,249	1,174	1,174	1,136
	109,098	112,143	110,453	106,942	107,204
Deductions from Rate Base					
Weather Normalization Reserve	4,931	3,349	(1,386)	(2,205)	-
Other Post Employee Benefits	19,066	27,975	35,822	42,519	48,719
Customer Security Deposits	846	750	974	993	700
Accrued Pension Obligation	4,173	4,480	4,795	5,111	5,428
Future Income Taxes	2,189	2,201	1,899	1,919	4,105
Demand Management Incentive Account	143	87	223	-	-
Excess Earnings	-	25	49	49	49
	31,348	38,867	42,376	48,386	59,001
Average Rate Base Before Allowances	903,849	952,907	1,006,063	1,046,075	1,090,985
Cash Working Capital Allowance	6,526	6,404	6,739	7,093	7,121
Materials and Supplies Allowance	5,445	5,619	6,280	6,328	6,624
Average Rate Base At Year End	915,820	964,930	1,019,082	1,059,496	1,104,730

[1] All amounts shown are averages.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Weighted Average Cost of Capital
($000s)

		Actual			Forecast	
		2013	**2014**	**2015**	**2016E**	**2017E**
1	**Average Capitalization**					
2	Debt	504,185	532,234	559,350	574,642	599,539
3	Preference Shares	9,031	8,965	8,944	8,939	8,939
4	Common Equity	414,578	429,174	451,501	474,884	495,199
5		927,794	970,373	1,019,795	1,058,465	1,103,677
6	**Average Capital Structure**					
7	Debt	54.35%	54.85%	54.85%	54.29%	54.32%
8	Preference Shares	0.97%	0.92%	0.88%	0.84%	0.81%
9	Common Equity	44.68%	44.23%	44.27%	44.87%	44.87%
10		100.00%	100.00%	100.00%	100.00%	100.00%
11						
12						
13	**Cost of Capital**					
14	Debt[1]	7.06%	6.72%	6.50%	6.15%	6.12%
15	Preference Shares	6.23%	6.21%	6.22%	6.18%	6.18%
16	Common Equity	9.16%	9.15%	8.98%	8.03%	7.30%
17						
18						
19	**Weighted Average Cost of Capital**					
20	Debt	3.84%	3.69%	3.57%	3.34%	3.31%
21	Preference Shares	0.06%	0.06%	0.05%	0.05%	0.05%
22	Common Equity	4.09%	4.05%	3.98%	3.60%	3.28%
23		7.99%	7.80%	7.60%	6.99%	6.64%

[1] Cost of debt is shown net of AFUDC. This is consistent with the cost of debt used in the calculation of return on rate base. For regulatory reporting purposes, the embedded cost of debt shown in Return 25 of the 2013 and 2014 Annual Report to the Board can be reconciled to the reported cost of debt above as follows:

	2013	2014
Cost of Debt (Line 14)	7.06%	6.72%
AFUDC	0.18%	0.27%
Cost of Debt - Return 25	7.24%	6.99%

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Rate of Return on Rate Base
($000s)

		Actual			Forecast	
		2013	**2014**	**2015**	**2016E**	**2017E**
1	Regulated Return on Equity	38,042 [1]	39,272	40,557	38,118	36,142
2	Return on Preferred Equity	563	557	556	552	552
3		38,605	39,829	41,113	38,670	36,694
4						
5	Finance Charges					
6	Interest on Long-term Debt	35,123	36,327	35,020	35,421	37,091
7	Other Interest	1,075	626	1,119	790	505
8	Amortization of Bond Issue Expenses	302	254	242	218	213
9	AFUDC	(891)	(1,435)	(1,240)	(1,067)	(1,087)
10		35,609	35,772	35,141	35,362	36,722
11						
12	Return on Rate Base	74,214	75,601	76,254	74,032	73,416
13						
14	Average Rate Base	915,820	964,930	1,019,082	1,059,496	1,104,730
15						
16	Rate of Return on Rate Base	8.10%	7.83%	7.48%	6.99%	6.65%

[1] The regulated return on equity for 2013 includes a $49,000 (net of income taxes) adjustment for excess earnings. See Return 13, line 2, of the 2013 Annual Report to the Board.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Inputs and Assumptions

Energy Forecasts : Energy forecasts are based on economic indicators taken from the Conference Board of Canada, Provincial Outlook, Winter 2016, Economic Forecast, dated February 4, 2016.

Revenue Forecast : The revenue forecast is based on the Customer, Energy and Demand forecast dated February 2016.

Forecast revenues for 2016 and 2017 reflects, (i) recovery through the RSA of amounts associated with the Energy Supply Cost Variance Adjustment Clause (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs, (iii) recovery through the RSA of amounts associated with the July 1, 2015 Hydro supply cost rate increase, (iv) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (iv) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio; all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 8 (2011), P.U. 13 (2013) and P.U. 18 (2015).

Purchased Power Expense : Purchased power expense reflects Newfoundland & Labrador Hydro's rates approved by the P.U.B. and the Customer, Energy and Demand Forecast dated February 2016.

Purchased power expense for 2013 to 2015 reflects the 3-year amortization of the December 31, 2011 balance in the Weather Normalization reserve of $7.0 million (before-tax).

Purchased Power expense also reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007). This mechanism provides for recovery of demand costs that are in excess of unit cost demand costs included in the most recent test year.

Employee Future Benefit Costs : Pension funding is based on the actuarial valuation dated as at December 31, 2014.

Pension expense and OPEBs expense discount rate is 4.10% for 2016 and 2017.

Forecast return on pension assets is assumed to be 5.75% for 2016 and 2017.

Cost recovery deferrals: In Order P.U. 13 (2013), the Board approved a 3-year amortization of (i) $1.0 million in hearing costs related to the 2013/2014 general rate application, (ii) $2.5 million in costs related to the 2012 cost of capital approved by the Board in Order No. P.U. 17 (2012), (iii) $4.7 million in costs related to the 2011 and 2012 deferred costs approved by the Board in Order Nos. P.U. 30 (2010) and P.U. 22 (2011), and (iv) $4.0 million in costs related to a 2013 revenue shortfall amount.

The 2015 to 2017 forecasts include the deferred recovery over a 7-year period of certain conservation program costs as reflected in the Application.

Depreciation Rates : Depreciation rates are based on the 2010 depreciation study.

Depreciation costs include an $89,000 reserve variance adjustment resulting from the 2010 depreciation study.

Newfoundland Power Inc.

Financial Performance
2013 to 2017E
Inputs and Assumptions

Operating Costs : Operating forecasts for 2016 reflect most recent management estimates. Operating forecasts for 2016 and 2017 reflect projected increases of 3.25% per year for labour, and non labour increases based upon the GDP deflator.

Capital Expenditure : Capital Expenditures for 2016 and 2017 are based on the 2016 capital budget approved on September 8, 2015.

Short-Term Interest Rates : Average short-term interest rates are assumed to be 1.83% for 2016 and 2.55% for 2017.

Long-Term Debt : A $75.0 million long-term debt issue was completed in September 2015. The debt is forecast for 30 years at a coupon rate of 4.446%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

A $75.0 million long-term debt issue is forecast to be completed in November 2016. The debt is forecast for 30 years at a coupon rate of 5.00%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

Dividends : Common dividend payouts are forecast based on maintaining a target common equity component near 45%.

Income Tax : Income tax expense reflects a statutory income tax rate of 29% for 2016 and 2017.

1st Revision Note: Updated for 2015 actuals and revised forecasts for 2016 and 2017.

Credit Rating Reports:
Moody's and DBRS

MOODY'S INVESTORS SERVICE

CREDIT OPINION
5 February 2016

Update

Rate this Research

RATINGS

NEWFOUNDLAND POWER INC.

Domicile	St. John's, Newfoundland, Canada
Long Term Rating	Baa1
Type	LT Issuer Rating - Dom Curr
Date	03 Aug 2009
Outlook	Stable
Date	08 Jun 2005

Please see the ratings section at the end of this report for more information.

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Newfoundland Power Inc.

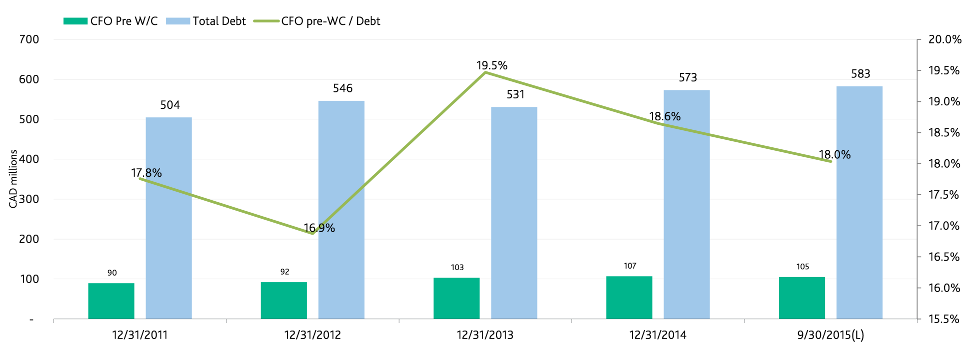
Update to Discussion of Key Credit Factors

Summary Rating Rationale

NPI's Baa1 issuer rating reflects the company's low business risk as a vertically integrated cost-of-service regulated utility with no unregulated business activities. Approximately 93% of NPI's power requirements are purchased from provincially owned Newfoundland & Labrador Hydro (Hydro), the cost of which is passed through to ratepayers. NPI's allowed Return on Equity (ROE) is 8.80% for 2013-2015, and we view the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) as one of the more supportive regulators in Canada because regulatory decisions are timely and balanced, deferral accounts reduce the risks from factors beyond management's control and NPI's 45% equity capital is among the highest authorized levels in Canada. The Baa1 rating is constrained by the risk of future cost recovery associated with the Province of Newfoundland and Labrador's sizeable Muskrat Falls hydroelectric project. This politically sensitive project is large relative to the provincial economy and is expected to place considerable upward pressure on the future electricity rates of NPI, a credit negative. The A2 rating of NPI's senior secured FMB reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets.

Exhibit 1

Historical CFO Pre W/C, Total Debt and CFO Pre W/C to Debt



Source: Moody's Financial Metrics

Credit Strengths

» Low risk regulated utility, primarily a T&D, with 93% purchased power from provincial generators

» Supportive regulatory environment

» Stable cash flow metrics with CFO pre-W/C to debt in the mid to high teens

Credit Challenges

» Upward pressure on rates due to the Muskrat Falls project

» Increased risks of timely cost recovery upon completion Muskrat Falls expected in 2018

Rating Outlook

The stable rating outlook reflects the PUB's regulation of NPI which we consider credit supportive. We expect the regulatory environment to remain supportive to credit quality, with a suite of timely recovery mechanisms, along with our expectation that relatively stable cash flow generation and the capital structure of NPI will continue to generate sustained CFO pre-WC to debt at the high end of the range of 15% to 17%.

Factors that Could Lead to an Upgrade

NPI's rating would likely be upgraded if CFO pre-WC to debt is forecast to be sustained above 17%. However, an upgrade of NPI's rating is unlikely without further clarity on the timing and size of the increases in electricity rates in relation to the Muskrat Falls hydroelectric project.

Factors that Could Lead to a Downgrade

We consider a downward revision in NPI's rating to be unlikely in the near term. However, NPI's rating would likely be downgraded if we perceived a meaningful reduction in the level of regulatory support combined with a sustained deterioration in NPI's financial metrics such as CFO pre-WC to debt falling into the low teens.

Key Indicators

Exhibit 2

Newfoundland Power Inc.

	12/31/2011	12/31/2012	12/31/2013	12/31/2014	9/30/2015(L)
CFO pre-WC + Interest / Interest	3.4x	3.5x	3.7x	3.9x	3.9x
CFO pre-WC / Debt	17.8%	16.9%	19.5%	18.6%	18.0%
CFO pre-WC – Dividends / Debt	7.8%	14.9%	15.2%	14.6%	15.8%
Debt / Capitalization	51.5%	51.9%	49.7%	50.7%	49.9%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics™
Source: Moody's Financial Metrics

Detailed Rating Considerations

LOW-RISK BUSINESS MODEL

NPI's rating reflects the company's low business risk as a cost of service regulated utility. NPI owns and operates a vertically integrated electric utility located on the island portion of the province of Newfoundland and Labrador and dominates that market, which is geographically isolated and effectively protected from potential competition. NPI serves roughly 90% of the province's electricity customers. The market is mature and NPI's electricity sales have tended to grow at a relatively low and predictable rate of 1-2% and we expect modest growth to continue. Historically, growth has not taxed NPI either operationally or financially due to relatively timely recovery of capital and operating costs.

Although NPI is vertically integrated, NPI's owned generation assets are regulated and represent only 14% of NPI's net property, plant and equipment at year-end 2014. Accordingly, we consider the business risk of NPI to be lower than that of a typical vertically integrated utility, which is often exposed to commodity price and volume risks or the operational, financial and environmental risks associated with electricity generation. However, NPI faces uncertainties due to the timing and size of expected rate increases in association with the Muskrat Falls hydroelectric project.

SUPPORTIVE REGULATORY AND BUSINESS ENVIRONMENT

NPI's operations benefit from a well-developed regulatory framework and business environments that we consider credit supportive. We consider the PUB's regulation of NPI to be credit supportive primarily because of a track record of reasonably timely and balanced decisions that enable NPI to generate stable and predictable cash flow and earn its allowed ROE which has not been directly subject to political interference. NPI has access to courts for disputes with the PUB.

The PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly reduce the risk of cost disallowances and support NPI's ability to fully recover costs on a timely basis. NPI submits a proposed capital plan for PUB approval annually before the next fiscal year. Furthermore, NPI is required to obtain PUB pre-approval for the issuance of any First Mortgage Bonds (FMB) or the incurrence of credit facilities with maturities exceeding one year, which we see as credit positives.

Several other cost recovery mechanisms reduce NPI's exposure to unexpected costs due to variations in purchased power costs, weather and pension and other post-employment benefit (OPEB) costs. While NPI foregoes some upside potential, the stability and predictability of its cash flows are increased. For example, the Rate Stabilization Account (RSA) facilitates timely recovery of purchased power costs in excess of those forecasted for rate-making purposes. This is particularly important since the marginal cost of power that NPI obtains from Hydro exceeds the average supply costs embedded in customer rates. The RSA provides for the amortization of the under or over collection over a 12 month period. Other mechanisms include the Weather Normalization Account, Conservation and Demand Management Deferral and the Demand Management Incentive Account (which limits NPI's exposure to variation in purchased power costs due to demand to 1% of demand costs reflected in the test year for rate-making purposes).

NPI is allowed to file a rate application based on a forward test year and forecast rate base. We view these mechanisms positively because they reduce revenue lag associated with large capital projects. NPI's allowed ROE of 8.8% has remained at that level for the period 2013-2015. While the ROE remains relatively low, it is mitigated by one of the highest deemed equity levels in Canada at 45%. NPI's outperformance, as suggested by CFO pre-W/C to debt of over 19% in 2013, 2014 and on an LTM basis as of September 30, 2015, reflected changes in regulated assets and liabilities and pension liability reductions. However, with the current allowed ROE, deemed equity layer and depreciation rate, we expect NPI to achieve sustainable CFO pre-W/C to debt consistent with our expectations and the current rating. On October 16, 2015, NPI filed its 2016/2017 general rate application with a decision expected in H1 2016. We do not expect the outcome to lead to a material change in credit quality, necessitating a rating action.

NPI IS INDEPENDENT OF FORTIS INC.

While NPI is one of a number of utility operating companies owned by Fortis, we consider NPI, like sister companies FortisAlberta Inc. (FAB: Baa1 stable), FortisBC Inc. (FBC: Baa1 stable) and FortisBC Energy Inc. (FEI: A3 stable), to be operationally and financially independent from Fortis, a credit positive Fortis has consistently demonstrated good management and support of its subsidiaries and we view NPI's access to the executive and strategic support of Fortis to be a credit positive. While we don't expect it, if required, and consistent with Fortis precedent, we have assumed that Fortis Inc. would provide extraordinary support to NPI, provided that the parent had the economic incentive and sufficient resources to do so. The credit quality of Fortis does not constrain the ratings of NPI.

Liquidity Analysis

NPI's liquidity arrangements are considered adequate in the context of its relatively stable cash flow and funding requirements.

In 2016, NPI plans to spend about $107 million on capital expenditures and pay dividends in amounts commensurate with maintaining the 45% deemed equity layer. Additionally, as of 30 September 2015, NPI had $37 million in short-term debt which relates primarily to a bond maturity in May 2016. With estimated cash flow from operations in the range of $110-120 million, we expect that any modest free cash flow shortfall is funded through NPI's bank credit facilities and adjustments to dividends paid which we expect to be about $20 million in 2016.

The company's core liquidity facility is a $100 million syndicated committed revolving credit facility that matures in August 2019. While the credit agreement contains a covenant that NPI maintain its debt to capitalization ratio at or below 65%, it does not include a material adverse change (MAC) clause or representation and warranty declaration prior to drawdown. This facility was undrawn and fully available at 30 September 2015. The company's next debt maturity is in May 2016.

Structural Considerations

The A2 rating of NPI's senior secured FMB reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets. This is consistent with the two notch differential between most senior secured debt ratings and senior unsecured debt ratings of investment-grade regulated utilities operating in North America. The differential is based on our analysis of the history of regulated utility defaults, which indicates that regulated utilities have experienced lower loss given default rates (higher recovery rates) than non-financial, non-utility corporate issuers.

Profile

Headquartered in St. John's, Newfoundland, Newfoundland Power Inc. (NPI) is a vertically integrated electric utility serving a customer base of over 260,000 residential and commercial customers. NPI operates under cost of service regulation and is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) under the Public Utilities Act (the Act). NPI purchases the majority of its power from Newfoundland and Labrador Hydro (not rated). NPI's installed generating capacity of 139 MW provides about 7% of its power supply. NPI is a wholly-owned subsidiary of Fortis Inc. (FTS, not rated), which is primarily a diversified electric and gas utility holding company also based in St. John's.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors

Newfoundland Power Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2015		Moody's 12-18 Month Forward View As of 2/2/2016 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	3.9x	Baa	3.6x - 4x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	19.1%	Baa	15% - 17%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.6%	Baa	11% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	50.1%	Baa	48% - 51%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching			0	0
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned				Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2015(L); Source: Moody's Financial Metrics™
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Ratings

Exhibit 4

Category	Moody's Rating
NEWFOUNDLAND POWER INC.	
Outlook	Stable
Issuer Rating -Dom Curr	Baa1
First Mortgage Bonds -Dom Curr	A2

Source: Moody's Investors Service

REPORT NUMBER 1014190

MOODY'S INVESTORS SERVICE

Rating Report

Newfoundland Power Inc.

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Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
First Mortgage Bonds	A	Confirmed	Stable
Preferred Shares - cumulative, redeemable	Pfd-2	Confirmed	Stable

Rating Update

On August 13, 2015, DBRS Limited (DBRS) confirmed the Issuer Rating and First Mortgage Bonds rating of Newfoundland Power Inc. (Newfoundland Power or the Company) at "A," and the Preferred Shares – cumulative, redeemable rating at Pfd-2, all with Stable trends. The confirmations reflect the stable nature of the Company's regulated electricity distribution business and its solid financial risk profile.

Newfoundland Power's business risk profile continues to be supported by the reasonable regulatory regime in Newfoundland and Labrador. The Company, which is regulated by the Board of Commissioners of Public Utilities (PUB), operates under a cost-of-service (COS) framework, which allows Newfoundland Power to recover all prudently spent operating expenses and earn a reasonable return. The Company currently has an allowed return on equity (ROE) of 8.80% and regulated capital structure of 45% common equity, which is comparable to its peers across Canada. Newfoundland Power also benefits from having a Rate Stabilization Account (RSA) and a Weather Normalization Account (WNA), which help reduce volatility in its earnings. These accounts limit the Company's exposure to power price risk as the RSA passes through to customers changes in the cost and quantity of fuel burned by the Company's main power supplier, Newfoundland and Labrador Hydro (NLH; rated "A" with a Stable trend by DBRS), while the WNA stabilizes earnings during extreme weather conditions.

Newfoundland Power filed an application with the PUB in April 2015 to approve a return on rate base for 2016 of 7.38%, a 2016 cost-recovery deferral of approximately $4.0 million and to defer the Company's next general rate application (GRA) filing to on or before June 1, 2016. The PUB denied the application and confirmed that the Company will be required to file its next GRA by October 16, 2015, to establish customer electricity rates for 2016. DBRS does not expect any material changes from the GRA but notes that a lower approved ROE is a possibility due to the current low interest rate environment. A modest decrease in the allowed ROE is not expected to have a material impact on the Company's operations.

The Company's financial risk profile remains solid with all key credit metrics in line with the current rating category. Newfoundland Power is currently experiencing elevated capital expenditures (capex; $117 million of gross capex in 2014) in order to maintain its distribution infrastructure and to connect new customers to the system. The Company, which has forecast average capex of $108 million for the next five years, has funded its capex and dividends through internally generated cash flow while modest free cash flow deficits have been funded with debt. DBRS expects the Company to continue to manage these deficits prudently through dividend management (quarterly common share dividends decreased to $0.23 per share for 2015, from $0.56 per share in 2014) and debt financing in order to maintain its leverage in line with the regulatory capital structure.

Financial Information

	12 mos. to June 30	For the year ended December 31				
(CA$ millions where applicable)	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
Total debt in capital structure	55.4%	55.3%	54.6%	55.2%	55.9%	53.7%
Cash flow/Total debt	16.2%	17.7%	18.2%	16.9%	18.5%	18.6%
EBIT gross interest coverage (times)	3.20	3.06	2.95	2.74	2.88	2.76
(CFO+interest)/(Interest+sinking fund payment)	3.12	3.18	3.16	2.90	3.02	3.01

Issuer Description

Newfoundland Power is a regulated utility that primarily distributes, but also generates and transmits, electricity to approximately 260,000 customers throughout the island portion of the Province of Newfoundland and Labrador (the Province). Newfoundland Power is a wholly owned subsidiary of Fortis Inc. (rated A (low) with a Stable trend by DBRS).

Rating Considerations

Strengths	Challenges

Strengths

1. Stable and supportive regulatory environment
Newfoundland Power operates in a stable and supportive regulatory environment that is based on COS regulation. The PUB allows for the pass-through of purchased power costs and an RSA is in place to absorb fluctuations in purchased power costs relating primarily to the cost of fuel oil used by NLH to generate electricity. Furthermore, the Company also has a WNA to stabilize earnings during extreme weather conditions.

2. Solid financial profile
Newfoundland Power has maintained a solid financial profile, underpinned by the Company's reasonable financial leverage and stable cash flows. During the last 12 months ended June 30, 2015 (LTM 2015), Newfoundland Power's total debt in capital structure remained low at 55.4%, while its cash flow-to-debt and EBIT interest coverage ratios remained solid at 16.2% and 3.20x, respectively.

3. Stable customer base
Newfoundland Power has a stable customer base, with power sales consisting solely of those to residential and commercial customers.

Challenges

1. Reliance on one major power supplier
Newfoundland Power relies heavily on NLH for its power supply, sourcing approximately 93% of its power requirements from this provider. The cost of power purchased from NLH is largely influenced by the market price of bunker C fuel, which is passed through to Newfoundland Power's customers through the RSA. Although the Company's rate increases have been reasonable, higher rates, driven by the high cost of oil in recent years and NLH's high capex program over the next few years, could make it more difficult for the Company to receive approval for future rate increases. However, NLH is looking to reduce its exposure to highly expensive and volatile oil. The Muskrat Falls project could potentially replace the oil-fired power generated at the Holyrood Thermal Generating Station with cleaner hydro-generated power.

2. Managing forecast risk
The Company's ability to accurately and consistently forecast electricity demand going forward, with respect to forecasting sales and managing the demand management incentive account (DMIA), is a challenge. However, through the DMIA, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs. In the deliberation of the final value to be placed in the DMIA, the PUB considers the merits of the Company's conservation and demand management activities.

3. Limited population growth
Electricity consumption growth in Newfoundland and Labrador is largely driven by growth in the customer base, which is dependent on population growth. Over the years, population growth in the Province has been relatively flat, as it is limited by the Province's geographic isolation.

Earnings and Outlook

(CA$ millions where applicable)	12 mos. to June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Net revenues	228	227	214	203	204	197
EBITDA	170	167	158	146	147	143
EBIT	115	113	107	98	104	100
Gross interest expense	36	37	36	36	36	36
Earning before taxes	50	49	46	45	50	51
Net income before non-recurring items	39	38	36	35	32	36
Reported net income	39	38	50	37	32	36
Actual return on equity	8.7%	8.6%	8.6%	8.9%	8.2%	8.9%

2014 Summary

- Earnings increased in 2014 largely due to higher electricity sales and the rebasing of customer rates effective July 1, 2013, reflecting growth in the rate base.
- This was partially offset by (1) higher operating costs related to the restoration and customer service efforts following the loss of generation supply from NLH and power interruptions in January 2014 and (2) higher depreciation due to the higher asset base.
- Reported net income in 2013 was positively impacted by $12.8 million of income tax recovery recorded in the year and a $1.2 million gain on the sale of land.

2015 Summary/Outlook

- Earnings in LTM 2015 increased modestly due to (1) lower operating costs compared to Q1 2014, which was impacted by the above-mentioned power interruptions and (2) lower interest expenses following the maturity of $29 million of first mortgage sinking fund bonds in August 2014.
- DBRS expects Newfoundland Power's earnings to be slightly higher in 2015, compared to 2014, reflecting the increase in the Company's rate base.

Financial Profile

(CA$ millions where applicable)	12 mos. to June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Net income before non-recurring items	39	38	36	35	32	36
Depreciation & amortization	56	54	52	48	43	44
Deferred income taxes and other	(2)	6	7	1	13	9
Cash flow from operations	**93**	**98**	**95**	**84**	**89**	**88**
Dividends paid	(17)	(24)	(23)	(11)	(51)	(16)
Capital expenditures	(123)	(113)	(89)	(82)	(79)	(75)
Free cash flow (bef. working cap. changes)	**(47)**	**(39)**	**(18)**	**(9)**	**(41)**	**(3)**
Changes in non-cash work. cap. items	12	5	(4)	(8)	(7)	6
Net free cash flow	**(35)**	**(34)**	**(22)**	**(17)**	**(48)**	**3**
Acquisitions & investments	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	(1)	45	0
Net equity change	(0)	(0)	(0)	0	(0)	0
Net debt change	35	34	22	17	(0)	(4)
Other	(0)	(0)	(0)	0	(0)	(0)
Change in cash	**0**	**(0)**	**0**	**(0)**	**(4)**	**(1)**
Total debt	575	552	518	496	478	475
Total debt in capital structure	55.4%	55.3%	54.6%	55.2%	55.9%	53.7%
Cash flow/Total debt	16.2%	17.7%	18.2%	16.9%	18.5%	18.6%
EBIT gross interest coverage (times)	3.20	3.06	2.95	2.74	2.88	2.76
Dividend payout ratio	43.1%	62.6%	64.8%	32.6%	156.2%	45.7%

Financial Profile (CONTINUED)

2014 Summary

- Newfoundland Power's financial profile remained solid with key credit metrics in line with the current rating category.
- The Company's cash flow from operations increased in 2014 largely due to the higher net income before non-recurring items for the year.
- Newfoundland Power had gross capex of approximately $117 million in 2014, with around $59 million spent on maintaining the distribution network and to connect new customers to the system. The higher capex for the year also reflected $14 million of supplemental capex for the replacement of the submarine cable system that supplies electricity to Bell Island.
- Newfoundland Power utilizes its annual dividend to maintain a long-term capital structure of 55% debt and 45% equity, as approved by the PUB for rate-setting purposes. In 2014, Newfoundland Power paid approximately $24 million in dividends to maintain its leverage in line with the approved capital structure.
- The Company incurred a free cash flow deficit of approximately $39 million in 2014, which was funded with debt.

2015 Summary/Outlook

- The Company's key credit metrics remained stable in LTM 2015. Although the cash flow-to-debt ratio decreased due to lower cash flow from operations and a higher debt load, it remained commensurate with the current rating category. The decrease in cash flow from operations was due to the timing of payments to NLH for power purchases.
- The PUB approved Newfoundland Power's 2015 capital plan of $94 million in October 2014. The Company has spent approximately $52 million as of June 30, 2015.
- The Company decreased its quarterly common share dividends to $0.23 per share, from $0.56 per share in 2014, in order to maintain its leverage in line with the regulatory capital structure.
- In April 2015, the PUB approved Newfoundland Power's application to issue up to $100 million of Series AO First Mortgage Bonds by December 31, 2015. The issuance is expected to be used to repay short-term borrowings ($91.5 million outstanding as of June 30, 2015).
- DBRS expects the Company to continue to maintain its approved capital structure through dividend management and debt financing.

Long-term Debt Maturities and Liquidity

- Newfoundland Power has a $100 million committed revolving unsecured credit facility expiring in August 2019 ($91.5 million outstanding as at June 30, 2015) and a $20 million uncommitted demand facility ($0 outstanding as at June 30, 2015).
- The credit facilities contain a covenant that states that the Company shall not declare or pay any dividends or make any other restricted payments if the debt-to-capitalization ratio exceeds 65%.

(CA$ millions — as at June 30, 2015)	2015-2016	2016-2017	2018-2019	Thereafter	Total
First mortgage sinking fund bonds	35.9	10.2	10.2	427.3	483.6
Related party loan	0.0	0.0	0.0	0.0	0.0
Credit facilities (unsecured)	91.5	0.0	0.0	0.0	91.5
Demand facility (uncommitted)	0.0	0.0	0.0	0.0	0.0
Total	**127.4**	**10.2**	**10.2**	**427.3**	**575.1**

Note: Gross debt; debt issue costs not subtracted from total debt.

- The debt repayment schedule is very modest in the near term. The most notable maturity was in 2014, which included the Series AD (approximately $29.0 million), which was repaid by the Company on August 1, 2014.

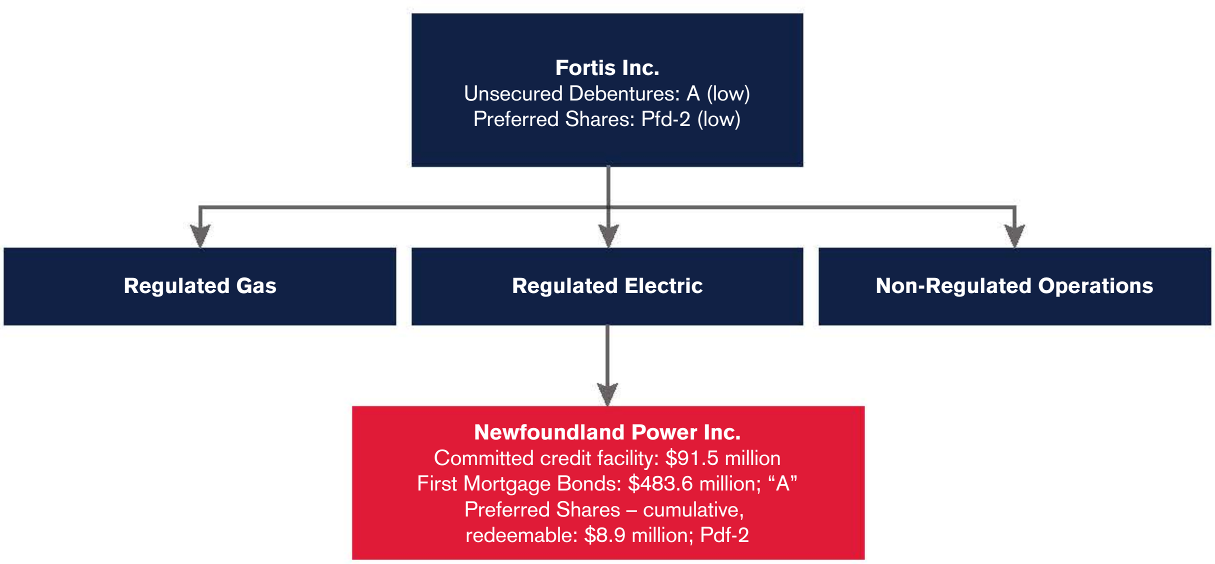
Long-term Debt Maturities and Liquidity (CONTINUED)

Securities Outstanding (CA$ millions)
First mortgage sinking fund bonds:

(CA$ millions)		June 30, 2015
$40 million Series AE, due 2016	10.900%	30.8
$40 million Series AF, due 2022	10.125%	31.2
$40 million Series AG, due 2020	9.000%	32.0
$40 million Series AH, due 2026	8.900%	32.8
$50 million Series AI, due 2028	6.800%	42.0
$75 million Series AJ, due 2032	7.520%	66.0
$60 million Series AK, due 2035	5.441%	54.0
$70 million Series AL, due 2037	5.901%	64.4
$65 million Series AM, due 2039	6.606%	61.1
$70 million Series AN, due 2043	4.805%	69.3
		483.6
	Related party loan	0.0
	Credit & demand facilities	91.5
		575.1
	Less: current portion	127.4
		447.7

- The First Mortgage Bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.
- The Company must meet an Earnings Test, whereby the net earnings are at least two times the annual interest charges on all bonds outstanding after any proposed additional bond issue. Net earnings are considered in a period of any 12 consecutive months terminating within 24 months preceding the delivery of such additional bonds.
- Second, the Company must meet the Additional Property Test, whereby the additional bonds must not exceed 60% of the fair value of the additional property.
- Given the availability of funds under the credit facilities and stable cash flow from operations, the Company's liquidity remains adequate to fund both working capital requirements and cash flow deficits.

Organizational Structure



As at June 30, 2015.

Regulation

Regulatory Overview

- Newfoundland Power is regulated by the PUB, which is responsible for setting electricity rates, approving capex and deciding on the appropriate capital structure and ROE for rate-setting purposes.
- Rates are set based on a cost-of-service methodology.
- On April 17, 2013, the PUB issued the Order on Newfoundland Power's 2013/2014 GRA, which established the Company's allowed ROE at 8.80% and common equity at 45% for the 2013 to 2015 rate years. This is consistent with the cost of capital allowed in 2012. DBRS views the capital structure as favourable and the ROE as reasonable when compared to other Canadian jurisdictions.
- The operation of the Automatic Adjustment Formula has been suspended until the next GRA.
- On July 1, 2014, customer electricity rates increased by approximately 2.0% on average due to the operation of the annual Rate Stabilization Plan.
- The Company's 2014 capital plan totalling $108.8 million was approved by the PUB and included $14.5 million associated with replacing the submarine cable system that supplies electricity to Bell Island.
- The PUB approved Newfoundland Power's 2015 capital plan of $94.2 million on October 9, 2014. The PUB additionally fixed the Company's average rate base for the year ending December 31, 2013, at $915.8 million.
- On July 1, 2015, customer electricity rates decreased by approximately 5.25% on average due to (1) a 10.0% rate decrease associated with the annual operation of the Rate Stabilization Plan, and (2) a 4.75% interim rate increase in the wholesale electricity rate charged by NLH to the Company.
- As a result of the elimination of the residential energy rebate by the Province effective July 1, 2015, residential customers will see an average rate increase of approximately 3.1%.
- Newfoundland Power filed an application with the PUB on April 15, 2015, to approve a return on rate base for 2016 of 7.38% with a range of 7.20% to 7.56%, a 2016 cost-recovery deferral of approximately $4.0 million and to defer the Company's next GRA filing to on or before June 1, 2016. The PUB denied the application on July 15, 2015, and confirmed that the Company will be required to file its next GRA by October 16, 2015, to establish customer electricity rates for 2016.

Regulator-Approved Accounts

- Deferral accounts are used to smooth the impact of realized expenses and events differing from forecast.
- ***Weather Normalization Reserve (WNR):*** The WNR reduces earnings volatility by adjusting electricity purchases and sales to eliminate the variance between normal weather conditions, based on long-term averages, and actual realized weather conditions.
- ***Rate Stabilization Account (RSA):*** The RSA allows Newfoundland Power to pass through costs related to changes in the price and quantity of fuel charged by NLH to the end consumer. On July 1 of each year, customer rates are recalculated in order to amortize, over the subsequent 12 months, the balance in the RSA as of March 31 of the current year. In the absence of rate regulation, these transactions would be accounted for in a similar manner; however, the amount and timing of the recovery would not be subject to PUB approval. To the extent that actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. Effective January 1, 2008, the PUB ordered that variations in purchased power expense caused by differences between the actual unit cost of energy and the cost reflected in customer rates be recovered from (refunded to) customers through the RSA.
- ***Demand Management Incentive Account (DMIA):*** Through the DMIA, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. Balances in this account are recorded as a regulatory asset or regulatory liability on Newfoundland Power's balance sheet. The final balance of regulatory assets and liabilities is determined by the PUB, which takes into consideration the merits of the Company's conservation efforts and demand management activities.
- ***Pension Expense Variance Deferral Account (PEVDA):*** The PEVDA is utilized when differences exist between the defined benefit pension expense calculated in accordance with designated accounting standards and the pension expense approved by the PUB for rate-setting purposes.
- ***Other Post-Employment Benefits:*** The other post-employment benefits cost deferral account (OPEB) is utilized when differences exist between the OPEB expense calculated in accordance with designated accounting standards and the OPEB expense approved by the PUB for rate-setting purposes.
- ***Excess Earnings Account (EEA):*** Any earnings which exceed the upper limit of the allowed range of return on rate base set by the PUB are credited to the Company's EEA. Amounts credited to the EEA are subject to further order of the PUB.

Newfoundland Power Inc.

(CA$ millions)	June 30	Dec. 31	
Assets	**2015**	**2014**	**2013**
Cash & equivalents	0	0	0
Accounts receivable	74	82	90
Regulatory assets	26	30	32
Prepaid expenses & other	5	6	4
Total Current Assets	**106**	**118**	**126**
Net fixed assets	1,005	984	915
Future income tax assets	182	177	171
Intangibles	16	16	15
Regulatory assets	149	151	169
Investments & others	4	4	4
Total Assets	**1,462**	**1,450**	**1,401**

	June 30	Dec. 31	
Liabilities and Equity	**2015**	**2014**	**2013**
S.T. borrowings	0	4	0
Accounts payable	50	80	82
Current portion L.T.D.	127	70	34
Other current liab.	18	18	18
Total Current Liab.	**195**	**172**	**135**
Long-term debt	448	478	484
Provisions	229	233	230
Deferred income taxes	126	120	116
Other L.T. liab.	1	1	6
Preferred shares	9	9	9
Common equity	454	437	422
Total Liab. & SE	**1,462**	**1,450**	**1,401**

	12 mos. to June 30	For the year ended December 31				
Balance Sheet & Liquidity & Capital Ratios	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
Current ratio	0.54	0.69	0.94	0.77	1.10	1.04
Total debt in capital structure	55.4%	55.3%	54.6%	55.2%	55.9%	53.7%
Cash flow/Total debt	16.2%	17.7%	18.2%	16.9%	18.5%	18.6%
(Cash flow-dividends)/Capex (times)	0.62	0.66	0.80	0.88	0.48	0.96
Dividend payout ratio	43.1%	62.6%	64.8%	32.6%	156.2%	45.7%
Coverage Ratios (times)						
EBIT gross interest coverage	3.20	3.06	2.95	2.74	2.88	2.76
EBITDA gross interest coverage	4.75	4.52	4.36	4.05	4.07	3.95
Fixed-charges coverage	3.14	3.00	2.88	2.68	2.82	2.69
Profitability Ratios						
EBITDA margin	74.5%	73.7%	73.9%	72.0%	72.2%	72.7%
EBIT margin	50.2%	49.9%	49.9%	48.6%	51.2%	50.6%
Profit margin	17.1%	16.7%	16.8%	17.1%	15.9%	18.1%
Return on equity	8.7%	8.6%	8.6%	8.9%	8.2%	8.9%
Return on capital	6.3%	6.5%	6.6%	6.8%	6.6%	6.8%

Operating Statistics

	For the year ended December 31				
Electricity sales — breakdown (GWh)	**2014**	**2013**	**2012**	**2011**	**2010**
Residential	3,613	3,531	3,441	3,407	3,311
General service	2,286	2,232	2,211	2,146	2,108
Total sales	**5,899**	**5,763**	**5,652**	**5,553**	**5,419**
Growth in volume throughputs	2.4%	2.0%	1.8%	2.5%	2.3%
Customers					
Residential	224,824	221,995	218,290	214,515	211,091
Commercial	34,055	33,623	33,241	32,648	32,335
Total	**258,879**	**255,618**	**251,531**	**247,163**	**243,426**
Energy generated and purchased (GWh)					
Energy generated	430	429	432	422	425
Energy purchased	5,817	5,678	5,544	5,456	5,308
Energy generated + purchased	**6,247**	**6,107**	**5,976**	**5,878**	**5,733**
Less: transmission losses + internal use	348	344	324	325	314
Total Sales	**5,899**	**5,763**	**5,652**	**5,553**	**5,419**
System losses and internal use	5.9%	6.0%	5.7%	5.9%	5.8%
Installed generation capacity (MW)					
Hydroelectric	97	97	97	97	97
Gas turbine	37	37	37	37	37
Diesel	5	5	6	7	7
Total	**139**	**139**	**140**	**140**	**140**
Native peak demand (MW)	1,343	1,281	1,241	1,166	1,206
Rate base ($ millions)	965	916	883	876	875
Growth in rate base	5%	4%	1%	0%	3%

Rating History

	Current	2014	2013	2012	2011	2010
Issuer Rating	A	A	A	A	NR	NR
First Mortgage Bonds	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, August 13, 2015.

Previous Report

- Newfoundland Power Inc., August 13, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Statements of Income
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Revenue from rates	662,704	669,160	666,202	680,421
2	Transfers from (to) the RSA	3,296	6,457	1,844	2,533
3		666,000	675,617	668,046	682,954
4					
5	Purchased power expense	449,647	448,896	451,206	448,648
6	Demand management incentive account adjustments	-	-	-	-
7		449,647	448,896	451,206	448,648
8					
9	Contribution	216,353	226,721	216,840	234,306
10					
11	Other revenue[1]	4,842	4,805	4,770	4,832
12					
13	Other expenses:				
14	Operating expenses[2]	58,174	58,574	59,569	59,969
15	Employee future benefit costs	18,564	18,564	15,852	15,852
16	Deferred cost recoveries and amortizations	-	(1,128)	-	564
17	Depreciation	54,627	55,528	57,623	58,555
18	Finance charges	35,383	35,446	36,745	36,873
19		166,748	166,984	169,789	171,813
20					
21	Income Before Income Taxes	54,447	64,542	51,821	67,325
22	Income taxes[2]	15,777	18,719	15,127	19,636
23					
24	Net Income	38,670	45,823	36,694	47,689
25	Preferred Dividends	552	552	552	552
26					
27	Earnings Applicable to Common Shares[2]	38,118	45,271	36,142	47,137
28					
29	**Rate of Return and Credit Metrics**				
30	Rate of Return on Rate Base (percentage)	6.99%	7.66%	6.65%	7.64%
31	Regulated Return on Book Equity (percentage)	8.03%	9.50%	7.30%	9.50%
32	Interest Coverage (times)	2.2	2.5	2.1	2.5
33	CFO Pre-W/C + Interest / Interest (times)	3.9	4.1	3.7	4.0
34	CFO Pre-W/C / Debt (percentage)	18.2%	19.3%	16.2%	18.2%

[1] Other revenue for proposed excludes interest on the RSA.
[2] Shown are after adjustment for non-regulated expenses.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Statements of Income
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Balance - Beginning	395,934	395,934	413,193	416,527
2	Net income for the period	36,548	43,701	34,405	45,400
3	Allocation of Part VI.1 Tax	252	252	252	252
4		432,734	439,887	447,850	462,179
5					
6	Dividends				
7	Preference shares	552	552	552	552
8	Common shares	18,989	22,808	10,733	26,420
9		19,541	23,360	11,285	26,972
10	Balance - End of Period	413,193	416,527	436,565	435,207

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Balance Sheets
($000s)

		2016		2017	
		Existing	Proposed	Existing	Proposed
1	**Assets**				
2	**Current assets**				
3	Accounts receivable	$ 89,311	$ 91,184	$ 95,051	$ 94,825
4	Materials and supplies	1,447	1,447	1,476	1,476
5	Prepaid expenses	1,315	1,315	1,341	1,341
6	Regulatory assets	16,810	20,704	13,021	16,102
7		108,883	114,650	110,889	113,744
8					
9	**Property, plant and equipment**	1,083,262	1,083,191	1,148,953	1,148,823
10	**Intangible assets**	21,457	21,457	23,115	23,115
11	**Regulatory assets**	322,309	323,673	318,919	319,319
12	**Defined benefit pension plans**	-	-	3,254	3,254
13	**Other assets**	1,188	1,188	1,160	1,160
14		$ 1,537,099	$ 1,544,159	$ 1,606,290	$ 1,609,415
15					
16					
17	**Liabilities and Shareholders' Equity**				
18	Current Liabilities				
19	Accounts payable and accrued charges	89,869	90,424	88,233	90,659
20	Interest payable	7,115	7,115	6,925	6,925
21	Defined benefit pension plans	233	233	228	228
22	Other post employment benefits	3,377	3,377	3,667	3,667
23	Current installments of long-term debt	(1,646)	664	44,119	44,863
24		98,948	101,813	143,172	146,342
25					
26	**Regulatory liabilities**	145,013	145,967	150,772	152,799
28	**Defined benefit pension plans**	1,862	1,862	-	-
29	**Other post employment benefits**	85,649	85,649	87,619	87,619
30	**Other liabilities**	700	700	700	700
31	**Deferred income taxes**	130,925	130,832	133,068	132,354
32	**Long-term debt**	581,549	581,549	575,134	575,134
33					
34	**Shareholders' Equity**				
35	**Common shares**	70,321	70,321	70,321	70,321
36	**Preference shares**	8,939	8,939	8,939	8,939
37	**Retained earnings**	413,193	416,527	436,565	435,207
38		492,453	495,787	515,825	514,467
39		$ 1,537,099	$ 1,544,159	$ 1,606,290	$ 1,609,415

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Statements of Cash Flows
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Cash From (Used In) Operating Activities**				
2	Net Earnings	$ 36,548	$ 43,701	$ 34,405	$ 45,398
3					
4	**Items not affecting cash:**				
5	Amortization of property, plant and equipment	56,794	57,887	59,581	60,714
6	Amortization of intangible assets and other	3,111	3,111	3,554	3,554
7	Change in long-term regulatory assets and liabilities	5,174	3,742	2,309	3,273
8	Deferred income taxes	2,603	2,510	2,143	1,522
9	Employee future benefits	3,978	3,978	556	556
10	Other	(230)	(230)	(238)	(238)
11		107,978	114,699	102,310	114,779
12					
13	Change in non-cash working capital	4,185	(1,033)	(6,169)	(1,387)
14		112,163	113,666	96,141	113,392
15					
16	**Investing Activities**				
17	Capital expenditures	(101,667)	(101,667)	(120,573)	(120,573)
18	Intangible asset expenditures	(6,123)	(6,123)	(5,028)	(5,028)
19	Contributions from customers and security deposits	5,450	5,450	1,550	1,550
20	Other	(473)	(473)	28	28
21		(102,813)	(102,813)	(124,023)	(124,023)
22					
23	**Financing Activities**				
24	Change in short term borrowings	(2,404)	(2,404)	-	-
25	Net proceeds (repayment) of committed credit facility	(25,755)	(23,439)	45,767	44,203
26	Proceeds from long-term debt	75,000	75,000	-	-
27	Repayment of long-term debt	(36,250)	(36,250)	(6,600)	(6,600)
28	Payment of debt financing costs	(400)	(400)	-	-
29	Dividends				
30	Preference Shares	(552)	(552)	(552)	(552)
31	Common Shares	(18,989)	(22,808)	(10,733)	(26,420)
32		(9,350)	(10,853)	27,882	10,631
33					
34	**Change in Cash**	-	-	-	-
35	**Cash (Bank Indebtedness), Beginning of Year**	-	-	-	-
36	**Cash (Bank Indebtedness), End of Year**	$ -	$ -	$ -	$ -

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Average Rate Base[1]
($000s)

		2016		2017	
		Existing	Proposed	Existing	Proposed
1	Plant Investment	987,519	987,068	1,042,782	1,041,415
2					
3	Additions to Rate Base				
4	Defined Benefit Pension Costs	96,802	96,802	94,045	94,045
5	Credit Facility Costs	48	28	32	-
6	Cost Recovery Deferral - Seasonal/TOD Rates	25	25	-	-
7	Cost Recovery Deferral - Hearing Costs	-	400	-	600
8	Cost Recovery Deferral - 2016 Revenue Shortfall	-	400	-	601
9	Cost Recovery Deferral - Conservation	8,893	8,893	11,991	11,991
10	Customer Finance Programs	1,174	1,174	1,136	1,136
11		106,942	107,722	107,204	108,373
12					
13	Deductions from Rate Base				
14	Weather Normalization Reserve	(2,205)	(2,205)	-	-
15	Other Post Employee Benefits	42,519	42,519	48,719	48,719
16	Customer Security Deposits	993	993	700	700
17	Accrued Pension Obligation	5,111	5,111	5,428	5,428
18	Future Income Taxes	1,919	1,794	4,105	3,728
19	Excess Earnings	49	25	49	-
20		48,386	48,237	59,001	58,575
21					
22	Average Rate Base Before Allowances	1,046,075	1,046,553	1,090,985	1,091,213
23					
24	Cash Working Capital Allowance	7,093	8,304	7,121	8,323
25					
26	Materials and Supplies Allowance	6,328	6,485	6,624	6,788
27					
28	Average Rate Base At Year End	1,059,496	1,061,342	1,104,730	1,106,324

[1] All amounts shown are averages.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Weighted Average Cost of Capital
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Average Capitalization**				
2	Debt	574,642	575,797	599,539	601,066
3	Preference Shares	8,939	8,939	8,939	8,939
4	Common Equity	474,884	476,552	495,199	496,188
5		1,058,465	1,061,288	1,103,677	1,106,193
6					
7	**Average Capital Structure**				
8	Debt	54.29%	54.26%	54.32%	54.33%
9	Preference Shares	0.84%	0.84%	0.81%	0.81%
10	Common Equity	44.87%	44.90%	44.87%	44.86%
11		100.00%	100.00%	100.00%	100.00%
12					
13					
14	**Cost of Capital**				
15	Debt	6.15%	6.15%	6.12%	6.13%
16	Preference Shares	6.18%	6.18%	6.18%	6.18%
17	Common Equity	8.03%	9.50%	7.30%	9.50%
18					
19					
20	**Weighted Average Cost of Capital**				
21	Debt	3.34%	3.34%	3.32%	3.33%
22	Preference Shares	0.05%	0.05%	0.05%	0.05%
23	Common Equity	3.60%	4.27%	3.28%	4.26%
24		6.99%	7.66%	6.65%	7.64%

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Rate of Return on Rate Base
($000s)

		2016		2017	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Regulated Return on Equity	38,118	45,271	36,142	47,137
2	Return on Preferred Equity	552	552	552	552
3		38,670	45,823	36,694	47,689
4					
5	Finance Charges				
6	Interest on Long-term Debt	35,421	35,421	37,091	37,091
7	Other Interest	790	852	505	633
8	Amortization of Bond Issue Expenses	218	218	213	213
9	AFUDC	(1,067)	(1,067)	(1,087)	(1,087)
10		35,362	35,424	36,722	36,850
11					
12	Return on Rate Base	74,032	81,247	73,416	84,539
13					
14	Average Rate Base	1,059,496	1,061,342	1,104,730	1,106,324
15					
16	Rate of Return on Rate Base	6.99%	7.66%	6.65%	7.64%

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Inputs and Assumptions

Energy Forecasts :	Energy forecasts are based on economic indicators taken from the Conference Board of Canada, Provincial Outlook, Winter 2016, Economic Forecast, dated February 4, 2016.
Revenue Forecast :	The revenue forecast is based on the Customer, Energy and Demand forecast dated February 2016.
	Forecast revenues for 2016 through 2017 reflects, (i) recovery through the RSA for January to July 2016 of amounts associated with the Energy Supply Cost Variance Adjustment Clause (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs, (iii) recovery through the RSA of amounts associated with the July 1, 2015 Hydro supply cost rate increase (iv) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (iv) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio; all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 8 (2011), P.U. 13 (2013) and P.U. 18 (2015).
Purchased Power Expense :	Purchased Power expense reflects Newfoundland & Labrador Hydro's rates approved by the P.U.B. and the Customer, Energy and Demand Forecast dated February 2016.
	Purchased Power Expense for the Existing forecasts reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007).
	Variances in demand costs under the Proposed forecasts are reflected in the 2016/2017 revenue requirements.
Employee Future Benefit Costs :	Pension funding is based on the actuarial valuation dated as at December 31, 2014.
	Pension expense and OPEBs expense discount rate is 4.10% for 2016 and 2017.
	Forecast return on pension assets is assumed to be 5.75% for 2015 through 2017.
Cost Recovery Deferrals:	The 2016 and 2017 forecasts include the deferred recovery over a 7-year period of certain conservation program costs as reflected in the Application.
	The 2016 and 2017 forecasts also include the deferred recovery over a 30 month period of $1.41 million due to a July 1, 2016 rate implementation date.

Newfoundland Power Inc.

Comparative Financial Forecasts
2016 & 2017
Inputs and Assumptions

Depreciation Rates : Depreciation costs for 2016 and 2017 include an $626,000 reserve variance adjustment resulting from the 2014 depreciation study.

Operating Costs : Operating forecasts for 2016 and 2017 primarily reflect projected increases of 3.25% per year for labour and non-labour increases based upon the GDP deflator.

The 2016 and 2017 forecasts include the deferred recovery over a 3-year period of $1.2 million in external costs related to the 2016 general rate application.

Capital Expenditure : Capital Expenditures for 2016 and 2017 are based on the 2016 capital budget approved on September 8, 2015.

Short-Term Interest Rates : Average short-term interest rates are assumed to be 1.83% for 2016 and 2.55% for 2017.

Long-Term Debt : A $75.0 million long-term debt issue was completed in September 2015. The debt was issued for 30 years at a coupon rate of 4.446%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

A $75.0 million long-term debt issue is forecast to be completed in November 2016. The debt is forecast for 30 years at a coupon rate of 5.00%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

Dividends : Common dividend payouts are forecast based on maintaining a target common equity component of 45%.

Income Tax : Income tax expense reflects a statutory income tax rate of 29% for 2016 and 2017.

1st Revision Note: Updated for revised forecasts for 2016 and 2017.

Newfoundland Power Inc.

Forecast Average Rate Base[1]
2016 &2017
($000s)

		2016P	2017P
1	Plant Investment	987,068	1,041,415
2			
3	Additions to Rate Base		
4	Defined Benefit Pension Costs	96,802	94,045
5	Credit Facility Costs	28	-
6	Cost Recovery Deferral - Seasonal/TOD Rates	25	-
7	Cost Recovery Deferral - Hearing Costs	400	600
8	Cost Recovery Deferral - 2016 Revenue Shortfall	400	601
9	Cost Recovery Deferral - Conservation	8,893	11,991
10	Customer Finance Programs	1,174	1,136
11		107,722	108,373
12			
13	Deductions from Rate Base		
14	Weather Normalization Reserve	(2,205)	-
15	Other Post Employee Benefits	42,519	48,719
16	Customer Security Deposits	993	700
17	Accrued Pension Obligation	5,111	5,428
18	Future Income Taxes	1,794	3,728
19	Excess Earnings	25	-
20		48,237	58,575
21			
22	Average Rate Base Before Allowances	1,046,553	1,091,213
23			
24	Cash Working Capital Allowance	8,304	8,323
25			
26	Materials and Supplies Allowance	6,485	6,788
27			
28	Average Rate Base At Year End	1,061,342	1,106,324

[1] Based upon proposed rates. All amounts shown are averages.

1st Revision Note: Updated for revised forecasts for 2016 and 2017.

Newfoundland Power Inc.

2016 Revenue Requirements[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	449,647	(751)	448,896
3	Operating Costs	58,174	400	58,574
4	Employee Future Benefit Costs	18,564	-	18,564
5	Amortization of Deferred Cost Recoveries	-	(1,128)	(1,128)
6	Depreciation	54,627	901	55,528
7	Income Taxes	15,777	2,942	18,719
8		596,789	2,364	599,153
9				
10	**Return on Rate Base**	74,032	7,215	81,247
11				
12	**2016 Revenue Requirement**	670,821	9,579	680,400
13				
14	**Deductions**			
15	Other Revenue[2]	(4,842)	37	(4,805)
16	Interest on Security Deposits	24	-	24
17	2013 Excess Earnings[3]	-	(68)	(68)
18	Energy Supply Cost Variance Adjustments	(5,461)	784	(4,677)
19	Other	2,162	(3,876)	(1,714)
20		(8,117)	(3,123)	(11,240)
21				
22	**2016 Revenue Requirement from Rates[4]**	662,704	6,456	669,160

[1] See *Section 5.3 2016 and 2017 Revenue Requirements* for a summary of the Company's 2016 Revenue Requirements proposals.

[2] Excludes equity component of capitalized interest and interest on the RSA.

[3] 2013 Excess Earnings as shown in Return 13 of the 2013 Annual Report to the Board.

[4] Existing revenue requirement for 2016 excludes price elasticity impacts related to revenue of $757,000. The required revenue increase of $7,213,000 in 2016 (see *Exhibit 9, (1st Revision)* , page 1 of 2, line 1, column E) is comprised of $6,456,000 and price elasticity impacts related to revenue of $757,000 (see *Exhibit 9, (1st Revision)* , page 1 of 2, line 1, column D).

Newfoundland Power Inc.

2017 Revenue Requirements[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	451,206	(2,558)	448,648
3	Operating Costs	59,569	400	59,969
4	Employee Future Benefit Costs	15,852	-	15,852
5	Amortization of Deferred Cost Recoveries	-	564	564
6	Depreciation	57,623	932	58,555
7	Income Taxes	15,127	4,509	19,636
8		599,377	3,847	603,224
9				
10	**Return on Rate Base**	73,416	11,123	84,539
11				
12	**2017 Revenue Requirement**	672,793	14,970	687,763
13				
14	**Deductions**			
15	Other Revenue[2]	(4,770)	(62)	(4,832)
16	Interest on Security Deposits	24	-	24
17	2013 Excess Earnings	-	-	-
18	Energy Supply Cost Variance Adjustments	(5,869)	5,869	-
19	Other	4,024	(6,558)	(2,534)
20		(6,591)	(751)	(7,342)
21				
22	**2017 Revenue Requirement from Rates[3]**	666,202	14,219	680,421

[1] See *Section 5.3, 2016 and 2017 Revenue Requirements* for a summary of the Company's 2017 Revenue Requirements proposals.

[2] Excludes equity component of capitalized interest and interest on the RSA.

[3] Existing revenue requirement for 2017 excludes price elasticity impacts related to revenue of $2,471,000. The required revenue increase of $16,690,000 in 2017 (see *Exhibit 9, (1st Revision)* , page 2 of 2, line 1, column E) is comprised of $14,219,000 and price elasticity impacts related to revenue of $2,471,000 (see *Exhibit 9, (1st Revision)* , page 2 of 2, line 1, column D).

1st Revision Note: Updated for revised forecasts for 2016 and 2017.

Newfoundland Power Inc.

2016 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	574,642	1,155	575,797
4	Preference Shares	8,939	-	8,939
5	Common Equity	474,884	1,668 [1]	476,552
6		1,058,465	2,823	1,061,288
7				
8	**Average Capital Structure**			
9	Debt	54.29%	(0.03%)	54.26%
10	Preference Shares	0.84%	0.00%	0.84%
11	Common Equity	44.87%	0.03% [1]	44.90%
12		100.00%	0.00%	100.00%
13				
14	**Cost of Capital**			
15	Debt	6.15%	0.00%	6.15%
16	Preference Shares	6.18%	0.00%	6.18%
17	Common Equity	8.03%	1.47% [1]	9.50%
18				
19	**Weighted Average Cost of Capital**			
20	Debt	3.34%	0.00%	3.34%
21	Preference Shares	0.05%	0.00%	0.05%
22	Common Equity	3.60%	0.67%	4.27%
23		6.99%	0.67%	7.66%
24				
25	**Return on Rate Base**			
26	Return on Debt	35,362	62	35,424
27	Return on Preference Shares	552	-	552
28	Return on Common Equity	38,118	7,153 [1]	45,271
29		74,032	7,215	81,247

[1] Reflects the Company's proposed return on common equity of 9.5 percent in 2016.

Newfoundland Power Inc.

2017 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	599,539	1,527	601,066
4	Preference Shares	8,939	-	8,939
5	Common Equity	495,199	989 [1]	496,188
6		1,103,677	2,516	1,106,193
7				
8	**Average Capital Structure**			
9	Debt	54.32%	0.01%	54.33%
10	Preference Shares	0.81%	0.00%	0.81%
11	Common Equity	44.87%	-0.01% [1]	44.86%
12		100.00%	0.00%	100.00%
13				
14	**Cost of Capital**			
15	Debt	6.12%	0.01%	6.13%
16	Preference Shares	6.18%	0.00%	6.18%
17	Common Equity	7.30%	2.20% [1]	9.50%
18				
19	**Weighted Average Cost of Capital**			
20	Debt	3.32%	0.01%	3.33%
21	Preference Shares	0.05%	0.00%	0.05%
22	Common Equity	3.28%	0.98%	4.26%
23		6.65%	0.99%	7.64%
24				
25	**Return on Rate Base**			
26	Return on Debt	36,722	128	36,850
27	Return on Preference Shares	552	-	552
28	Return on Common Equity	36,142	10,995 [1]	47,137
29		73,416	11,123	84,539

[1] Reflects the Company's proposed return on common equity of 9.5 percent in 2017.

1st Revision Note: Updated for revised forecasts for 2016 and 2017.

Newfoundland Power Inc.

2016 Revenue Requirement to Revenue From Rates Reconciliation
($000s)

		Existing	Proposed	Difference	Price Elasticity[3]	Proposed Increase[4]
		A	**B**	**C**	**D**	**E**
1	**Revenue From Rates**	662,704 [1]	669,160 [2]	6,456 [5]	757	7,213
2						
3	**RSA Charges[6]**	(6,300)	(6,292)	8	(8)	-
4						
5	**MTA Charges**	16,280	16,425	145	19	164
6						
7	**Total**	672,684	679,293	6,609	768	7,377

[1] 2016 Revenue from existing rates from *Exhibit 7, (1st Revision)* , page 1 of 2.

[2] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from *Exhibit 7, (1st Revision)* , page 1 of 2. Revenue from proposed rates reflect revenue from existing rates for January to June plus revenue from proposed rates for July to December.

[3] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.

[4] Difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C plus Column D).

[5] *Exhibit 7, (1st Revision)* of the Application indicates a required increase in 2016 revenue from rates of $6,456,000 net of elasticity effects. This increase in revenue requirement includes the effect of the 2016 revenue shortfall amortization.

[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2015.

Newfoundland Power Inc.

2017 Revenue Requirement to Revenue From Rates Reconciliation
($000s)

	Existing A	Proposed B	Difference C	Price Elasticity[3] D	Proposed Increase[4] E
Revenue From Rates	666,202[1]	680,421[2]	14,219[5]	2,471	16,690
RSA Charges[6]	(6,313)	(6,288)	25	(25)	-
MTA Charges	16,334	16,687	353	60	413
Total	676,223	690,820	14,597	2,506	17,103[7]

[1] 2017 Revenue from existing rates from *Exhibit 7, (1st Revision)*, page 2 of 2.
[2] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from *Exhibit 7, (1st Revision)*, page 2 of 2.
[3] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.
[4] Difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C plus Column D).
[5] *Exhibit 7, (1st Revision)* of the Application indicates a required increase in 2017 revenue from rates of $14,219,000, net of elasticity effects. This increase in revenue requirement includes the effect of the 2016 revenue shortfall amortization.
[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2015.
[7] See *Exhibit 10, (1st Revision)*, Column E.

1st Revision Note: Updated for revised revenue requirement from rates for 2016 and 2017.

Newfoundland Power Inc.

2017 Average Customer Billing Impacts
($000s)

Forecast Impacts by Rate Class Under Existing and Proposed Rates
(includes July 1, 2015 RSA and MTA)

	Category	Existing Rates	Adjustment Due to Price Elasticity	Adjusted Existing Rates	Proposed Rates	Increase	Rate Increase
1		(A) [1]	(B) [2]	(C) [3]	(D) [4]	(E) [5]	(F) [6]
2							
3	1.1 Domestic	427,877	(2,320)	425,557	438,874	13,317	3.1%
4	1.1S Domestic Seasonal	2,141	-	2,141	2,208	67	3.1%
5	Total Domestic	430,018	(2,320)	427,698	441,082	13,384	3.1%
6							
7	2.1 General Service 0-100 kW	90,681	(176)	90,505	92,803	2,298	2.5%
8	2.3 General Service 110-1000 kVA	100,142	-	100,142	100,158	16	0.0%
9	2.4 General Service over 1000 kVA	36,224	-	36,224	37,143	919	2.5%
10	Total General Service	227,047	(176)	226,871	230,104	3,233	1.4%
11							
12	4.1 Street and Area Lighting	16,282	-	16,282	16,695	413	2.5%
13	Forfeited Discounts	2,876	(10)	2,866	2,939	73	2.5%
14							
15	**Total**	676,223	(2,506)	673,717	690,820	17,103	2.5%

[1] Column A is the forecast revenue plus RSA and MTA under existing rates, based on the 2017 test year sales forecast without elasticity impacts. See *Exhibit 9, (1st Revision)* , page 2 of 2, Column A.

[2] Column B is the elasticity impact on existing customer billings reflecting a 2.5% average increase in customer rates.

[3] Column C is the forecast customer billings under existing rates including elasticity impacts (Column A + Column B).

[4] Column D is the forecast customer billings under proposed rates including elasticity impacts. See *Exhibit 9, (1st Revision)* , page 2 of 2, Column B.

[5] Column E is the difference between forecast under proposed rates and that under existing rates adjusted for elasticity (Column D - Column C).

[6] Column F is the forecast rate increase (Column E / Column C).

1st Revision Note: Updated for revised revenue requirement from rates for 2016 and 2017.

NEWFOUNDLAND POWER INC.
Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
Domestic - Rate #1.1		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.19/month
Exceeding 200 Amp Service	$20.70/month	$21.19/month
Energy Charge - All kilowatt hours	10.573 ¢/kWh	10.904 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.19/month
Exceeding 200 Amp Service	$20.70/month	$21.19/month
Prompt Payment Discount	1.5%	1.5%
Domestic - Rate #1.1S		
Basic Customer Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.19/month
Exceeding 200 Amp Service	$20.70/month	$21.19/month
Energy Charge		
Winter Seasonal	11.526 ¢/kWh	11.857¢/kWh
Non-Winter Seasonal	9.276 ¢/kWh	9.607 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	$15.70/month	$16.19/month
Exceeding 200 Amp Service	$20.70/month	$21.19/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.
Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
G.S. 0-100 kW (110 kVA) - Rate #2.1		
Basic Customer Charge		
Unmetered	NA	$17.44/month
Single Phase	$21.93/month	$21.44/month
Three Phase	NA	$27.44/month
Demand Charge Regular	$9.10/kW - winter	$9.29/kW - winter
	$6.60/kW - other	$6.79/kW - other
Energy Charge		
First 3,500 kilowatt-hours	10.534 ¢/kWh	10.807 ¢/kWh
All excess kilowatt-hours	7.791 ¢/kWh	7.994 ¢/kWh
Maximum Monthly Charge	18.775 ¢/kWh + B.C.C.	19.247 ¢/kWh + B.C.C.
Minimum Monthly Charge		
Unmetered	NA	$17.44/month
Single Phase	$21.93/month	$21.44/month
Three Phase	$36.03/month	$33.44/month
Prompt Payment Discount	1.5%	1.5%
G.S. 110-1000 kVA - Rate #2.3		
Basic Customer Charge	$50.08/month	$50.08/month
Demand Charge	$7.86/kVA-winter	$7.86/kVA-winter
	$5.36/kVA-other	$5.36/kVA-other
Energy Charge		
First 150 kWh per kVA of demand (max. 50,000)	9.156 ¢/kWh	9.156 ¢/kWh
All Excess kWh	7.286 ¢/kWh	7.286 ¢/kWh
Maximum Monthly Charge	18.775 ¢/kWh + B.C.C.	19.247 ¢/kWh + B.C.C.
Minimum Monthly Charge	$50.08/month	$50.08/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.
Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
G.S. 1000 kVA and Over - Rate #2.4		
Basic Customer Charge	\$85.13/month	\$87.26/month
Demand Charge	\$7.41/kVA-winter \$4.91/kVA-other	\$7.54/kVA-winter \$5.04/kVA-other
Energy Charge		
First 75,000 kWh	8.605 ¢/kWh	8.822 ¢/kWh
All Excess kWh	7.041 ¢/kWh	7.220 ¢/kWh
Maximum Monthly Charge	18.775 ¢/kWh + B.C.C.	19.247 ¢/kWh + B.C.C.
Minimum Monthly Charge	\$85.13/month	\$87.26/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

Street and Area Lighting Rates

		July 1, 2015 Existing Rates	July 1, 2016 Proposed Rates
Fixtures			
Sentinel/Standard			
High Pressure Sodium	100W	$16.78	$17.29
	150W	21.13	21.23
	250W	29.88	29.34
	400W	41.17	40.13
Post Top			
High Pressure Sodium	100W	$18.20	$18.70
Poles			
Wood		$7.24	$6.57
30' Concrete or Metal, direct buried		10.46	9.38
45' Concrete or Metal, direct buried		14.74	15.37
25' Concrete or Metal, Post Top, direct buried		7.99	6.97
Underground Wiring (per run)			
All sizes and types of fixtures		$12.80	$15.98

FIVE-YEAR CONSERVATION PLAN:
2016 – 2020

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND POWER
A FORTIS COMPANY

October 2015

CONTENTS

1.0 EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro ("Hydro") and Newfoundland Power have offered customer energy conservation programs on a joint and coordinated basis under the *takeCHARGE* brand since 2009. These programs provide a range of information and financial supports to help customers manage their energy usage.

The joint *Five-Year Conservation Plan: 2016-2020* (the "2016 Plan") builds on this experience, and continues to reflect the principles underlying two previous joint, multi-year conservation plans developed by Hydro and Newfoundland Power (the "Utilities").[1] It reflects refinement of the opportunities identified in a recently updated conservation potential study (the "2015 CPS") through in-depth local market research and program cost benefit analysis.

The 2016 Plan represents both growth and evolution of the Utilities' joint customer energy conservation program portfolio. It includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. The approach outlined in this plan will remain flexible to address the changing provincial landscape, in terms of customer expectations, market conditions for energy efficient products, and electrical system costs. The 2016 Plan also addresses customer support and education, program planning and evaluation processes, as well as the Utilities' costs and cost recovery arrangements.

The total estimated energy savings for 2016 through 2020 are 883 GWh.[2] Total estimated costs through this period are $41.1 million.

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[1] The *Five-Year Energy Conservation Plan: 2008-2013* was filed with the Board on June 27, 2008. The *Five-Year Energy Conservation Plan: 2012-2016* was filed on September 14, 2012.

[2] The energy savings indicated throughout the *Five-Year Energy Conservation Plan: 2016-2020* represent *gross* energy savings achieved by customers. These savings reflect all technologies installed by participating customers since program implementation. *Net* energy savings would reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings; and (ii) program *free ridership* (an estimate of participants who would have chosen the more efficient product without the program).

2.0 BACKGROUND

2.1 Planning Context

Hydro and Newfoundland Power have collaborated on customer energy conservation program planning and delivery for the past 8 years. The programs offered jointly under the takeCHARGE brand have included a variety of information and financial supports which help customers manage their energy usage. The Utilities' provision of energy conservation programming is responsive to customer expectations, supports efforts to be responsible stewards of electrical energy resources and is consistent with provision of least cost, reliable electricity service. Initiatives address conservation opportunities for customers in each sector: residential, commercial and industrial.

The Utilities' practice has been to refresh their joint strategic plans for customer conservation programming every three to four years. This ensures programs achieve long term goals while being responsive to changes in customer expectations, market barriers, technology developments, and economics. Current program offerings are based on the Five Year Energy Conservation Plan: 2012-2016 ("the 2012 Plan").

One of the key inputs into the 2016 Plan was the outcome of the Conservation Potential Study ("CPS"), completed by the Utilities in 2015. The CPS identified cost-effective energy and demand reduction measures, outlined general parameters for program development, and quantified achievable energy savings potential by sector and end-use. The results of the CPS are considered with the Utilities' experience and other factors in the local market to determine potential programs and energy saving targets for the 2016 Plan.

The Utilities' conservation planning is coordinated with overall planning for the electrical system. Significant changes to the Island Interconnected System are anticipated to occur in this planning period. Interconnection of the Muskrat Falls hydroelectric development is forecast for 2018 and will include the Island's first connection to the

North American grid. As a result, there is uncertainty with respect to the marginal cost of energy and capacity on the Island Interconnected System beyond 2017.

Schedule A provides the current forecast marginal cost of energy and capacity for 2015-2035.[3] The forecast indicates a decrease in the marginal cost of energy beginning in 2018. This effectively reduces the value of energy savings arising from customer energy conservation programming, and limits the types of programs that can be cost effectively offered.

Costs of electricity supply additions are expected to be incorporated into customer rates starting in 2018, putting upward pressure on customers' rates. This is expected to increase customers' motivation to conserve energy to manage their electricity costs. Also, the recent economic slowdown is anticipated to continue into this planning period and will influence customer behaviour with regards to conservation.

The 2008 and 2012 Five Year Conservation and Demand Management Plans, delivered jointly by the Utilities, had focused primarily on energy conservation. This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Generating Station) which justified such a focus. The events of recent winters have since brought to light issues with peak load and generation capacity on the Island Interconnected System which are anticipated to continue into this planning period. The 2016 Plan therefore considers demand management opportunities as well as energy conservation.

The Utilities have been offering some form of customer energy conservation programming since 1991, and have achieved significant energy savings over this time. The current forecast, particularly for insulation, anticipates diminishing returns. For example, the remaining potential for energy savings through insulation upgrades has

[3] The marginal costs used to determine cost effectiveness of the customer energy conservation programs are based on the most recent marginal cost forecast as projected by Hydro in February 2015. These estimates are currently under review by Hydro to incorporate the forecast interconnection with the North American grid. Once more current estimates are available, they will be incorporated in the screening process.

been impacted by changes to the National Building Code requiring basement insulation in new homes, as well as barriers to retrofitting many of the eligible existing homes. This is consistent with experience in other North American jurisdictions where utility programming has harvested the “low hanging fruit” and subsequently has moved on to address more challenging and costly opportunities.

Energy conservation programming has also been affected by technology advancements and changes to standards. Lighting product standards changes have effectively eliminated availability of incandescent bulbs for consumers. At the same time, LED technology has advanced and become more affordable and available. The pace of this change has been even faster than anticipated in the 2012 Plan. This is demonstrated by higher than projected uptake in the Utilities’ Instant Rebate component of the Small Technologies program.

The Utilities continue to work with the Provincial Government, through the Office of Climate Change and Energy Efficiency, regarding policy development for energy conservation and efficiency, and particularly potential impacts and approaches to building codes, product standards and broader market transformation objectives.

Many of the influences on the provincial energy conservation market can be seen in other North American jurisdictions. In recent years, many jurisdictions have experienced decreasing marginal costs of energy and increasing program costs due to maturing conservation programs. As a result, utilities and program administrators have revised their approach to economic analysis of energy conservation. The Utilities have conducted research on current economic evaluation practices. A summary of this research is provided in Schedule B. It indicates that Canadian jurisdictions use the Total Resource Cost (“TRC”) test as their primary benefit cost test for program screening, with the Program Administrator Cost test as a secondary test. Only one of the seven Canadian utilities researched used Ratepayer Impact Measure as a primary benefit cost test for program screening. In the United States, most jurisdictions follow similar practices with over 70% using TRC as the primary benefit cost test and 2% using Ratepayer Impact Measure for program screening.

2.2 Energy Conservation Programs

Based on the 2012 Plan, the Utilities have jointly offered customer energy conservation programs which provide both information and financial incentives to encourage customer installation of energy efficient technologies.[4] In addition, Hydro has offered programming for its customers, such as incentives for commercial customers in its isolated system service territories, where market conditions and system costs differ.

Table 1 shows, by sector, the portfolio of programs that have been offered under the 2012 Plan.[5]

Table 1
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation Thermostat ENERGY STAR Window[6] HRV Block Heater Timer Small Technologies Isolated Systems Community Program	Lighting Business Efficiency Program Isolated Business Efficiency Program	Industrial Energy Efficiency Program

4 Once installed, these more energy efficient technologies provide energy savings for the customer throughout the life of the product. For example, an HRV has an estimated life of 15 years and will result in energy savings benefits throughout that period.

5 The Utilities also engage in demand management activities, including Newfoundland Power's Curtailable Service Rate Option and Hydro's interruptible load arrangements with its Industrial Customers.

6 The ENERGY STAR Window Program concluded at the end of 2014.

Schedule D summarizes the energy savings and costs for the customer energy conservation programs offered by the Utilities from 2009 through 2015.

Residential Programs

Table 2 provides a summary of residential customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).[7]

Table 2
Residential Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	2010	2011	2012	2013	2014	2015F	Total
Energy Savings	2.5	7.1	18.6	28.5	38.4	51.5	65.7	**212.3**

The takeCHARGE residential programs are expected to result in aggregate energy savings of approximately 212.3 GWh by the end of 2015.[8]

Insulation Program

As a result of the updates to the National Building Code in 2012, several changes were made to the Insulation Program. New homes are no longer eligible and the minimum R-value requirements for existing homes have been increased. As well, the rebate structure was revised to provide a higher, easy-to-calculate rebate. Customers can receive an incentive of 75% of basement wall or ceiling insulation material costs up to $1,000, and 50% of attic insulation material costs up to $1,000.

[7] Energy savings include savings arising from all technologies installed by all participants since program implementation. This reflects the fact that these technologies provide energy savings benefits for the customer throughout the life of the product.

[8] Since implementation in 2009, there have been approximately 36,650 participants and over 638,000 at-the-cash rebates were provided on energy efficient products in the takeCHARGE residential customer programs.

Thermostat Program

High efficiency programmable and electronic thermostat replacements allow customers to conserve energy at relatively low cost and effort. Eligibility for the programs is limited to electrically heated homes, determined on the basis of annual energy usage.

ENERGY STAR Window Program

This program concluded at the end of 2014. After 5 years, and over 9,200 participating customers, the program had achieved its objective of making more efficient windows the standard in the local market.

Heat Recovery Ventilator Program

This program promotes the installation of high efficiency heat recovery ventilators (“HRVs”). HRVs have been widely used in new home construction in the province since the 1990s, to control humidity and air quality. The HRV program has experienced lower than projected participation since its launch in late 2013.[9] There has been improvement in 2015, and the Utilities will continue to monitor and evaluate this program in order to find opportunities to increase participation.

Block Heater Timer Program

Hydro provided giveaways and at-the-cash coupons for block heater timers to customers in Hydro’s Labrador Interconnected System from 2012-2014. While vehicle engine block heaters are used extensively in this area, timers are rarely used. Instead of using electricity throughout the night, block heater timers allow vehicle owners to reduce the amount of time that electricity is used to warm the vehicle engine. Due to lack of participation this program was not continued past 2014 but commercial customers can take advantage of this technology through the Business Efficiency Program (“BEP”) or the Isolated Systems Business Efficiency Program (“ISBEP”).

[9] The Utilities have received feedback regarding low customer knowledge of home ventilation, with many customers being unaware of the purpose of a HRV in their home and how it can save energy. Also, there are complexities in the supply chain for acquiring a high efficiency HRV which can be problematic for potential participants.

Small Technologies

The small technologies program is supported by retail partners and appeals to a broad customer group as it does not involve a major home renovation. The program uses different marketing approaches for two different groups of energy efficient products.

The Instant Rebate component offers relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home.[10] Participation and energy savings results in the first two years of the program have exceeded the forecast in the 2012 plan. The Appliance and Electronics component offers incentives that are relatively higher value and available by mail-in and online application throughout the year.[11]

Isolated Systems Community Program

Following two pilot programs in 2010 and 2011, Hydro launched a full-scale, energy efficiency direct install program in 2012. The program includes direct installations of energy efficient products at no cost to homes and businesses.[12] The program also focuses on customer education and building capacity in the communities by hiring and training local representatives. These representatives work in their own communities to promote the program, provide information on energy use, and install the products.

[10] Products include LED lighting, motion sensors, timers, dimmer switches, smart power strips and more.
[11] Products include energy efficient clothes washers, full-size refrigerators, full-size freezers and TVs.
[12] Products include low-flow showerheads and aerators, CFLs, smart power strips, and hot water tank and pipe insulation.

Commercial Programs

Table 3 provides a summary of commercial customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).

Table 3
Commercial Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	2010	2011	2012	2013	2014	2015F	Total
Energy Savings	0.2	0.9	2.4	3.3	3.9	6.5	11.4	**28.6**

The takeCHARGE commercial programs will result in estimated aggregate energy savings of approximately 28.6 GWh by the end of 2015.[13]

Commercial Lighting Program

The Commercial Lighting Program targets reduced energy use through efficient lighting in commercial buildings, including high performance T8 and T5 fluorescent lighting and LED exit signs. This program has primarily been promoted through local lighting distributors by discounting lighting products at time of purchase.

The Business Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings from custom projects, and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency improvement projects. It also includes rebates for specific measures on a per unit basis.

[13] Since implementation in 2009, there have been over 1,050 participants in the takeCHARGE commercial customer programs.

Isolated Systems Business Efficiency Program

This program is targeted toward commercial customers located in Hydro's isolated system communities. This custom program provides incentives based on the energy savings from efficiency improvement projects. This allows customers to implement energy efficient technologies that are suitable for their specific buildings, equipment and operations.

Industrial Programs

Table 4 provides a summary of industrial customer energy savings achieved through Utility customer energy conservation programs from 2009 through 2015(F).

Table 4
Industrial Program Energy Savings
2009 through 2015(F)
(GWh)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015(F)**	**Total**
Energy Savings	-	-	0.2	3.3	3.3	25.6	25.6	58.0

The takeCHARGE Industrial Energy Efficiency program will result in estimated aggregate energy savings of approximately 58.0 GWh by the end of 2015.[14]

The Industrial Energy Efficiency Program is a custom program that responds to the unique needs of Hydro's transmission level industrial customers. This program provides financial support for engineering feasibility studies of efficiency projects and for project implementation costs. The Industrial program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011 and the last being submitted in 2013. No projects were completed in 2013 as focus was put on feasibility studies for work to be completed in 2014. The program then underwent an assessment by an external third party in 2014 and was re-launched as a full program in 2015.

[14] Since implementation in 2009, there have been 5 projects completed under the takeCHARGE Industrial Energy Efficiency Program.

2.3 Education & Support

The Utilities continue to provide energy efficiency education and support to customers through a variety of channels, which include a joint website, outreach activities, school presentations and partnerships with other organizations.

Table 5 shows the number of customer-initiated contacts with the Utilities for energy conservation information from 2010 through 2015 YTD.

Table 5
Customer Contacts for
Energy Conservation Information

	2010	2011	2012	2013	2014	2015YTD
Contact Centre Inquiries	11,704	12,624	9,793	9,630	10,830	5,328
Website Visits	52,013	72,996	49,202	76,278	186,003	197,973

The majority of customers chose electronic means of communication with the Utilities to obtain information on energy conservation and rebate programs. This is consistent with promotion of the takeCHARGE website as the primary resource for customer inquiries and information. Customer visits to the takeCHARGE website grew by 144% from 2013 to 2014. Activity in the first eight months of 2015 shows continued growth, with approximately 80% of website visits via a mobile device. This increase is related to increased promotion, changes to existing programs, and addition of new programs.

The Utilities have participated in an average of 214 community outreach events each year since 2012. This included presentations to retailers and suppliers, senior citizens, trade allies and other groups. takeCHARGE information booths were displayed at home shows, trade fairs, and retail stores across the province. The Utilities also offer a number of outreach events, such as the annual takeCHARGE of Your Town Challenge and Energy Efficiency Week. Through these outreach activities, members of the takeCHARGE team assisted customers with their energy efficiency questions, while raising awareness of energy conservation and the takeCHARGE rebate programs.

Over the last three years the takeCHARGE *Kids in Charge* K-I-C Start school program, has provided energy efficiency and conservation education support to students throughout Newfoundland and Labrador. This has included delivering in classroom presentations and an annual contest for primary and elementary students. In 2014, takeCHARGE partnered with the Provincial Office of Climate Change and Energy Efficiency to extend this program through the Hotshots pilot program.[15] As a result, in 2014-15 school year, over 11,000 students in 106 schools throughout the province participated in 448 presentations about energy conservation.

Trade allies play an integral role in helping customers make knowledgeable decisions regarding energy conservation and related home improvements. Retail partners display information about takeCHARGE programs and energy efficiency products in their stores and in flyers, as well as during special promotional events.[16] Similarly, the Utilities are continuing to grow a network of business to business service providers and suppliers that support the commercial and industrial sectors.[17]

The Utilities have also developed partnerships with a variety of other organizations that share common goals for the province's conservation market, including the Association of Newfoundland and Labrador Realtors, the Canadian Home Builders Association, Newfoundland and Labrador Housing Corporation, and the Canadian Mortgage and Housing Corporation.

[15] Through the HotShots pilot, the Province provided funding and support for additional in-class presentations, curriculum linked teacher materials, and a contest for high school students.

[16] The Utilities continue to work with over 160 retail store partners, 11 manufacturers/distributors, and approximately 50 HRV installers.

[17] These include lighting equipment manufacturers and distributors, electrical and HVAC contractors, and engineering firms.

Table 6 shows costs for education and support for the period 2009-2015(F).

Table 6
Conservation Education & Support
Costs 2009-2015(F)
($000s)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015(F)**	**Total**
Education	666	486	428	426	501	647	693	3,847
Support	236	206	219	222	186	174	158	1,401
Total	**902**	**692**	**647**	**648**	**687**	**821**	**851**	**5,248**

2.4 Planning & Evaluation

Planning

The focus of the Utilities' CDM planning process is to develop a 5-year plan for the implementation of comprehensive customer energy conservation and demand management programs around the technologies that were determined to have conservation potential in the provincial market. The completion of the CPS in 2015 effectively initiated the development of the 2016 Plan.

Programs are developed and revised through consultation with the various market stakeholders, such as government, trade allies and local interest groups, to gather feedback on program delivery strategy.

Table 7 shows costs for conservation planning for the period 2009-2015(F).[18]

Table 7
Conservation Planning
Costs 2009-2015(F)
($000s)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Planning	401	429	509	404	462	958	1,202	4,365

Variations in annual conservation planning costs primarily reflect the periodic nature of the Utilities' program planning and research activities.

Research

In 2013, the Utilities completed a joint Commercial Facility Equipment Inventory ("CFEI") on 54 commercial facilities.[19] This research provided information on how commercial customers use electricity, through an inventory and analysis of all mechanical and electrical equipment in each facility.[20] This data was used as a direct input into the CPS conducted in 2015.

In 2014, Newfoundland Power and Hydro jointly conducted a survey to gather information regarding electricity end uses in the residential sector. The information gathered was used to assess potential electricity savings opportunities, and was used as a direct input into the current planning cycle. These results are also being taken into account in making adjustments to the *takeCHARGE* programs. For example, because

[18] Conservation planning costs include costs related to surveys and research, development of the potential study and the five-year plan, and general administration.

[19] The CFEI was completed by CBCL Limited, a consultant that conducted on-site facility audits for participating commercial customers. CBCL Limited is a leading employee owned multidisciplinary engineering and environmental consulting firm in Atlantic Canada.

[20] The CFEI found, for example, that the food retail sector are the largest users of electricity on a square footage basis of the customers audited, followed by the manufacturing/fish processing sector.

of survey findings regarding the prevalence of CFLs, these have been removed from the Instant Rebates Program beginning in the fall of 2015.[21]

Newfoundland Power completed research on ductless mini-split heat pumps ("MSHP") from 2013 to 2015. The objectives of this research were to assess the current MSHP market in Newfoundland, the use of the MSHP as a supplementary heat source and the potential impact of MSHPs on the electricity system. The results indicate that MSHP are more efficient and do save energy compared to electric baseboard heat.[22] This analysis also shows that there is not likely to be peak demand reduction on the electricity system from installation of MSHPs.[23] Customer demand for MSHP products has grown significantly in recent years and continues to be strong. However, there are issues with availability of qualified installers and customer understanding of product quality requirements.

In the fall of 2014, Newfoundland Power launched a pilot program to assess the economic, market, and technical feasibility of direct load control to reduce overall peak demand. This pilot was initiated in response to the constraints on system capacity that became evident after the events in January of 2013 and 2014. The pilot involved controlling hot water tanks in approximately 500 customer homes in Paradise and Mount Pearl. Demand reduction achieved by the direct load control events on average was 0.6 kW per participant, and for events that included all participants, approximately

21 Customers were asked what types of lighting they use in areas of their house where they spend the most time: 63% reported that they use incandescent bulbs, 53% CFLs, and 18% LEDs (multiple responses allowed). In another question, 31% of respondents claimed to have changed all their bulbs to more energy efficient types, and 45% indicated that they have begun to change to more energy efficient types.

22 Approximately half of the homes in the study recorded energy savings after installation of the MSHP. In these homes, electricity usage declined by an average of 5,300 kWh or 19% per year, with savings ranging from 7% to 50%. The remaining homes recorded an increase or no change in energy usage. This appears to reflect factors such as heating of additional living space, fuel switching, or operational issues with the MSHP.

23 Savings at time of system peak are dependent on a number of factors such as the efficiency and defrost cycle of the MSHP system, and temperature. A high efficiency MSHP may be capable of providing peak savings in warmer parts of the province but not in colder regions, while a less efficient MSHP may not be capable of providing peak savings in any region. On colder weekdays, the study observed little difference in the load profile of the MSHP homes vs. electric baseboard homes, and occasionally the MSHP homes' peak load was slightly higher.

298 kW of demand reduction was achieved. The Pilot results also indicate that a full scale provincial program does not meet the economic requirements.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project, which is supported by the Utilities and administered by Hydro, began in September 2014 and aims to assess whether real time display of energy use has a positive effect on electricity conservation behavior. The pilot involves approximately 750 customers: 250 with an in-home display device, 250 with an in-home display device as well as electricity conservation information in a monthly mail out, and 250 with only the electricity conservation information. Monitoring of participants will continue until January 2016 and the final report will be submitted to Government by end of March 2016.

Evaluation

The customer energy conservation programs are continuously evaluated by the Utilities on their energy savings, market impacts and delivery process effectiveness. Additional review by external third party evaluators has also been conducted. Program evaluation findings are used to refine program design and implementation details on an ongoing basis, as well as support further planning.

For example, the third party residential program evaluation in 2013 found that two-thirds of windows sold in the province were ENERGY STAR, which supported the Utilities' decision to conclude the ENERGY STAR Windows Program.[24]

Economic and energy savings evaluation of the customer energy conservation programs is performed annually. Program participants are required to provide certain information on program rebate applications. This information ranges from technical data, such as the R-value of installed insulation, or efficiency rating of a HRV to the type of heating in the home and its geographic location. Analysis of this data allows the

[24] The 2013 residential program evaluation was conducted DNV GL- Energy, headquartered in Burlington, Massachusetts, and specializing in evaluating programs that promote energy efficiency, demand response, and distributed generation.

Utilities to accurately estimate the energy savings for each program and perform industry standard economic cost-benefit tests.

2.5 CDM Costs & Cost Recovery

Table 8 provides a summary of the customer energy conservation program and general costs of the Utilities from 2009 through 2015(F).[25]

Table 8
Conservation Costs
2009 through 2015 (F)
($000s)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015F**	**Total**
Programs								
Residential	1,386	2,322	3,473	3,436	3,921	4,277	5,188	24,003
Commercial	79	95	216	214	355	926	1,388	3,273
Industrial	57	226	103	173	89	1,244	19	1,910
Total Programs	1,522	2,643	3,791	3,823	4,365	6,447	6,595	29,186
General	1,303	1,121	1,156	1,052	1,149	1,779	2,054	9,614
Total	**2,825**	**3,764**	**4,947**	**4,875**	**5,514**	**8,226**	**8,649**	**38,800**

The Utilities' costs related to conservation programs have increased from approximately $2.8 million in 2009 to $8.6 million in 2015. This primarily reflects the addition of new customer energy conservation programs in 2013, specifically the Small Technologies Program and the Business Efficiency Program. This also reflects the increased levels of customer participation and rebates related to the joint takeCHARGE program portfolio. The expansion of customer programs has also resulted in increasing energy savings.

25 This cost summary does not include (i) costs related to programs offered independently by the Utilities prior to June 2009; (ii) costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management); and (iii) costs related to Hydro's interruptible service arrangements with its Industrial Customers.

Details of the Utilities' customer energy conservation program and general costs are provided in Schedule C.

The Utilities each bear the costs related to the provision of customer energy conservation programming in their own service territory. General conservation and program costs, such as customer rebates and costs related to responding to customer inquiries are incurred directly by each utility. Costs which are incurred jointly, such as provincial mass media advertising, are split on an 85% / 15% basis between Newfoundland Power and Hydro, respectively.[26]

Cost Recovery

Newfoundland Power's current conservation cost recovery practice reflects Board Order No. P.U. 13 (2013). Conservation program costs are deferred and amortized over a seven-year period. Through the annual operation of the Company's Rate Stabilization Adjustment, customer rates are adjusted to reflect any difference between the conservation program costs included in the most recent test year and the costs actually incurred. Newfoundland Power's annually recurring general conservation costs related to providing general customer information, community outreach and planning are expensed in the year in which the costs are incurred.

Hydro's current customer rates, as approved by the Board in Order No. P.U. 8 (2007), include recovery of approximately $0.4 million in costs related to management and planning of conservation programming. In each year from 2009 to 2014, inclusive, Hydro has deferred recovery of direct program costs related to the expansion of customer energy conservation programming under the 2008 Plan and 2012 Plan.[27] As of August 14, 2015, associated with a general rate application filed by Hydro on July 30, 2013, and an amended general rate application filed by Hydro on November 10, 2014,

[26] This approach to division of jointly incurred costs reflects the proportion of customers served by each utility.

[27] The deferred recovery of these costs in 2009, 2010, 2011, 2012, 2013, and 2014 were approved by the Board in Order Nos. P.U. 14(2009), P.U. 13(2010), P.U. 4(2011), P.U. 3(2012), P.U. 35(2013), and P.U. 43(2014), respectively.

the Consumer Advocate, Newfoundland Power, the Industrial Customer Group and Vale, with participation by Board Hearing Counsel, have engaged in negotiations with Hydro. As a result, these parties agreed that "Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved."[28]

3.0 PLAN: 2016-2020

3.1 Conservation Potential & Program Selection

The programs included in the 2016 Plan have been selected based on a number of considerations. Opportunities identified in the 2015 CPS are a key input and these have been further assessed by the Utilities in terms of engineering, market and economic viability. Consideration has also been given to the experience of the Utilities and others in the local marketplace, feedback from customers, as well as experience shared from other Canadian jurisdictions.

Conservation Potential Study

In June 2015, a comprehensive study was completed of electricity conservation and demand management potential for the province.[29] This Conservation Potential Study estimated the potential for electrical energy and demand savings by sector and by electricity system from 2015-2029. It also identified specific technologies available to assist in achieving that potential. The CPS essentially provides a framework, consistent with current North American practices, within which to assess conservation programming. The findings enabled the Utilities to quickly focus on cost effective technologies and begin assessment of market characteristics to guide program concept development.

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28 Newfoundland and Labrador Hydro – Amended General Rate Application – Parties' Settlement Agreement dated August 14, 2015.

29 ICF International (previously called Marbek) conducted Conservation Potential Studies for the Utilities in 2007 and 2015. ICF International is a leading environmental and energy management consultancy and has extensive experience conducting Conservation Potential Studies in Canada.

Electrical system marginal costs of supply are used in the CPS to screen the economic viability of more efficient technologies.[30] For the current CPS, these costs were based on the most recent marginal cost forecast as projected by Hydro in February 2015.[31] These estimates are currently under review. Once Hydro's marginal cost study is completed, the CPS results will be reassessed. If such a review results in changes to the list of cost effective technologies with conservation potential, these will be considered in future updates to the 2016 Plan.

Figure 1 shows the baseline provincial energy usage forecast which was input to the 2015 CPS (the reference case), and the upper and lower achievable potentials estimated by the Potential Study.[32]

30 Technologies are considered to be economically viable when the cost of saving one kWh or kW of electricity is equal to, or less than, the marginal cost of supplying the electricity.

31 The 2015 CPS included an analysis of the sensitivity of potential technologies to changes in marginal costs. The analysis was based on a range of + 30% to – 10% of the February 2015 forecast marginal costs. It indicated a modest level of variability in technology viability and resulting conservation results. Please see CPS, section 7.5 Energy Efficiency Supply Curve, filed with the Board September 15, 2015.

32 The reference case is based on the provincial energy usage forecast from 2014. After this study was completed the energy usage forecast decreased due to the economic downturn, mainly in the industrial sector. The achievable potential is defined as the portion of the economic conservation potential that is achievable through utility interventions and programs given institutional, economic and market barriers. The upper achievable potential is considered to be the best case scenario with all market barriers removed, such as capital cost and product accessibility. The lower achievable potential is considered a business as usual scenario with the existing market barriers remaining in place.

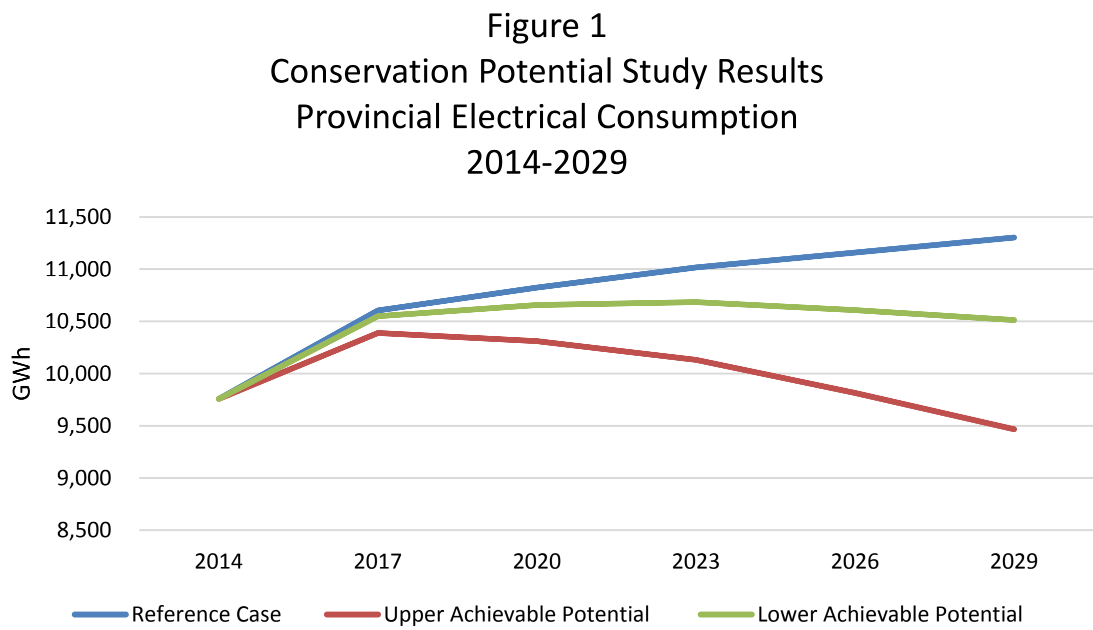


Figure 1 shows that, over time, the cumulative effects of implementing cost effective efficient technologies can significantly reduce forecast growth in electricity usage.[33]

Figures 2 and 3 show the results of the CPS regarding achievable demand reduction potential from energy efficiency measures ("Energy Efficiency") and from demand response specific measures ("Demand Response") by 2020.[34]

[33] At the end of the first estimation interval, in 2017, the CPS shows a range of 55 GWh for the lower achievable potential savings and 215 GWh for the upper achievable potential savings. This compares with annual savings of approximately 116 GWh currently estimated in the Plan for the same timeframe.

[34] The Commercial and Industrial sector includes Hydro's large transmission level Industrial customers as well as Newfoundland Power's general service customers.

Figure 2
Lower Achievable Demand
Reduction Potential
Island Interconnected System
2020
(MW)

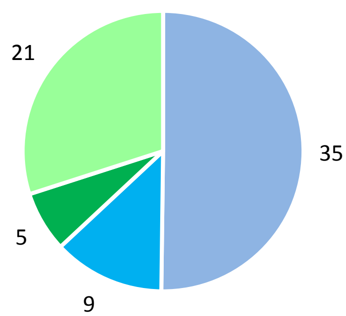
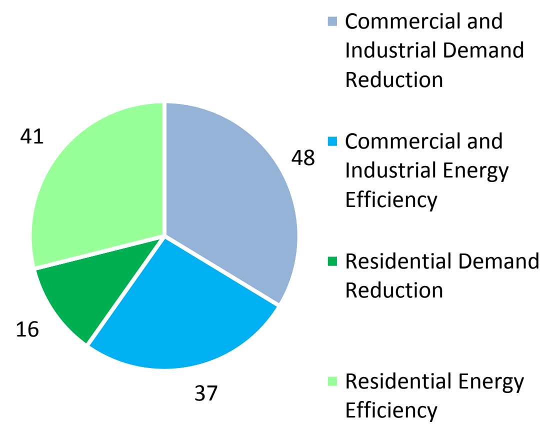


Figure 3
Upper Achievable Demand
Reduction Potential
Island Interconnected System
2020
(MW)



Figures 2 and 3 show 70 MW for the lower potential and 142 MW for the upper potential demand reduction on the Island Interconnected System.[35] Installation of energy efficiency measures that reduce consumption during times of peak demand account for approximately 43% and 55% of the lower and upper achievable demand reduction, respectively, by 2020.[36]

The majority of the demand reduction potential was identified in the Commercial and Industrial sectors. Specifically, the Industrial sector represents about 87% and 74% of the total lower and upper achievable demand reduction, respectively. The demand reduction technologies identified through the CPS as having the most potential included curtailable load arrangements with commercial and industrial customers and direct load control of residential hot water tanks.

[35] 21+35+9+5=70 and 41+16+37+48= 142
[36] (21+9)/70=43% and (37+41)/142=55%.

Selection

The technologies that passed the economic screening of the CPS were reviewed in detail to assess their possible inclusion in the 2016 Plan. Local market research was conducted to identify barriers to broader adoption of more efficient technologies, such as capital cost, market availability and awareness. This included consultation with market stakeholders and trade allies, as well as discussions with other utilities.

Once existing market barriers were identified, a program strategy was then developed to attempt to overcome those barriers. Costs associated with the program were considered and the cost effectiveness of the program determined.[37] This more detailed review of program costs and benefits can cause a technology that had passed economic screening in the CPS to fail the economic tests required of CDM programs.

Economic Screening

The Utilities' economic screening of the customer energy conservation programs has previously required a positive result for both the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") cost-benefit tests.[38] Recent research indicates Canadian and U.S. utility practice has changed to focus on the TRC and Program Administrator Cost ("PAC") tests.[39]

The Utilities recommend adoption of the TRC as the primary means of program economic screening, and the PAC as a secondary means. This is consistent with current North American practice, and is appropriate based on the electrical system marginal costs and program objectives in this jurisdiction. Based on this recommendation the programs included in the 2016 Plan passed economic screening

[37] Program cost estimates include marketing, delivery and administration, incentives, measurement and verification, and evaluation.

[38] In Order No. P.U.7 (1996-97), the Board required customer conservation programs to be evaluated with respect to rate impact, as well as the total resource costs. The Utilities' have interpreted this Order to require a TRC of 1.0 and a RIM of 0.8 as described in *Newfoundland Power Inc. – 2009 Conservation Cost Deferral Application, Section 2: Proposed Customer Program Portfolio* filed with the Board October 29, 2008.

[39] See Section 2.1, page 4, and Schedule B.

based on the TRC and PAC.[40] The Utilities' will continue to monitor changes to economic screening practices to appropriately reflect evolving program characteristics and electrical system costs.

3.2 Conservation & Demand Management Programs

The 2016 Plan builds on the outcomes of the 2012 plan as well as the experience of the Utilities. Programs included in the 2016 Plan address conservation opportunities in all three sectors: residential, commercial, and industrial. The 2016 Plan includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. These conservation programs are broadly consistent with programs offered by utilities in other jurisdictions.

Table 9 shows, by sector, the portfolio of programs to be offered under the 2016 Plan.

Table 9
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation Thermostat HRV Small Technologies Isolated Systems Community Program Benchmarking	Business Efficiency Program Isolated Business Efficiency Program	Industrial Energy Efficiency Program

[40] Application of the RIM test would result in elimination of a number of programs, including Benchmarking, HRV, and Small Technologies.

Residential Programs

Insulation, Thermostat and HRV Programs

These existing joint incentive programs primarily target space heating energy savings, and will continue to be offered as part of the 2016 Plan. The remaining eligible market for the Insulation and Thermostats programs has been declining in recent years. The HRV program has had limited participation due to barriers related to customer understanding and market complexity. These programs will be continuously evaluated to ensure program cost effectiveness.

Small Technology Program

The jointly offered Small Technologies program will continue to use different marketing approaches for the two different groups of energy efficient products.

The Instant Rebate component will continue to offer relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home. As part of the 2016 Plan, Instant Rebates will include additional technologies.[41] It is anticipated that this component will end during 2018 as LED lighting becomes the norm in the residential lighting market.[42] Most of the energy savings benefits in this program are related to customers' early adoption of LED lighting from less efficient technologies, and energy savings from non-lighting products are not expected to be sufficient to offset the program delivery costs.

Incentives for the Appliance and Electronics component will continue to be available through 2017. At that time, anticipated reductions in marginal costs on the electricity system will effectively reduce the value of energy saving benefits, causing the program to fail economic screening.

[41] As part of the 2016 Plan, Instant Rebates will include additional technologies, such as faucet aerators, door bottom weather stripping, door adhesive weather stripping, window insulation kits, electrical outlet gaskets, and caulking.

[42] The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Isolated Systems Community Program

The existing format for this program will continue to be offered to customers in Hydro's isolated system communities through 2017. Information and feedback collected in 2014 and 2015, particularly for the direct install component, will be used to evaluate and plan for the Isolated Systems Community Program beyond 2017.

An Appliance Retirement component will be added to this program beginning in 2016, targeting at least one community. Older inefficient appliances will be removed from participating homes and routed for appropriate disposal.[43]

Benchmarking

This new joint program will promote customer behaviour changes to encourage more efficient energy use. Benchmarking involves using social norms to encourage neighbourly competition to reduce electricity consumption. This program will include comparison of participant households' energy consumption with their energy history and that of similar households. Participants will also receive personalized home energy reports that provide household specific electricity usage information and savings tips to help them reduce energy use and lower their electricity bills. This program will be available to customers from 2016 to 2019.

Commercial Programs

Lighting Program

Beginning in 2016, existing commercial lighting program products will become prescriptive rebates under the Business Efficiency Program, including the fluorescent high bay, high performance T8 fluorescent lamp and LED exit sign. This change will allow for more specific marketing initiatives and increased awareness of the rebates available for these technologies.

[43] This component will be evaluated to determine whether a broader program would be cost effective.

Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts have become the market standard. Industry partners indicate that approximately 55% of ballasts sold in the province in 2014 meet the program efficiency criteria.[44]

Business Efficiency Program

The Business Efficiency Program, offered jointly by the Utilities, will continue to provide custom and prescriptive incentives to commercial customers for energy efficiency improvements. Continued growth in customer participation and energy savings are anticipated for this program. The Utilities will increase the customer education and awareness component of this program to include sector-based identification of energy efficiency opportunities. New technologies will also be added to the program's list of prescriptive incentives.[45]

Isolated Systems Business Efficiency Program

This program will continue through 2020, and will be offered to Hydro's commercial customers located in isolated system communities. The program will continue to provide incentives based on the energy savings of customer projects, similar to the Business Efficiency Program.

Industrial Programs

Industrial Energy Efficiency Program

Through 2020, this customized program will continue to offer support and financial incentives based on energy savings for retrofit of industrial process equipment for Hydro's transmission level industrial customers.[46]

44 Note that U.S. Federal Regulations are now equivalent to this ballast efficiency specification.

45 These include: LED screw-in lamps, high bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems, and low flow pre-rinse spray valves.

46 The Industrial Energy Efficiency Program's cost effectiveness and potential energy savings will be evaluated on a year to year basis.

Customer Energy Savings

Table 10 shows forecast customer energy reduction estimates for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 10
2016 Plan Energy Reduction Estimates
2016 through 2020
(GWh)

	2016	2017	2018	2019	2020	Total
Residential	80.4	102.7	118.1	123.5	111.7	536.4
Commercial	18.7	27.6	37.5	48.6	61.4	193.8
Industrial	30.6	30.6	30.6	30.6	30.6	153.0
Total	129.7	160.9	186.2	202.7	203.7	883.2

The programs in the 2016 Plan will result in estimated aggregate customer energy savings of approximately 883.2 GWh from 2016 through 2020. Customer energy savings are forecast to increase annually through 2020, due to expansion of the program portfolio and the addition of program technologies for the residential and commercial sectors.

Several program offerings are expected to be concluded during the planning period. These include the Small Technologies program and the Benchmarking program. Design of alternate programming for the residential sector is anticipated through the Utilities' program planning in 2018.

Demand Management

The previous conservation and demand management plans have focused primarily on energy conservation.[47] However, the Utilities' customer energy conservation programs have resulted in quantifiable demand savings.

The technologies identified through the CPS as having the most potential for demand reduction included direct load control of residential hot water tanks and curtailable load arrangements with commercial and industrial customers. Recent research has identified issues with the cost effectiveness of residential load control on the Island Interconnected System. As a result, this measure is not included in the 2016 Plan.[48] The Utilities will continue to pursue curtailment opportunities with their larger customers.[49]

A new component will also be added to the Business Efficiency Program ("BEP") to include a custom incentive for demand reduction measures that are economically viable and that provide measureable demand reduction during peak times.[50]

47 This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Station) which justified such a focus.

48 Although residential load control on the Island Interconnected System does not make economic sense, Hydro's isolated communities served by diesel generation have higher marginal costs which may make the program cost effective.

49 Hydro currently has interruptible load arrangements with its Industrial Customers which have potential for more than 90 MW of capacity assistance. Newfoundland Power currently has 16 customers participating in its Curtailable Rate Option, providing 10.4 MW of potential load reduction.

50 More information on the custom demand component of the BEP can be found in Schedule C.

Table 11 shows forecast customer demand reduction estimates for the customer energy conservation programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 11
2016 Plan Demand Reduction Estimates
2016 through 2020[51]
(MW)

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Residential	3.3	4.7	5.0	4.3	1.4	18.6
Commercial	2.1	2.0	2.3	2.5	2.8	11.7
Total	5.4	6.7	7.3	6.8	4.2	30.3

The Utilities' takeCHARGE customer energy conservation programs are forecast to achieve approximately 30.3 MW in peak demand reduction through 2020. This demand reduction will occur annually for the life of the installed technologies.[52]

[51] Hydro does not forecast demand reduction for their transmission level industrial customers.
[52] For example, a customer who installs basement insulation in 2014 will achieve approximately 0.9 kW of annual peak demand reduction for the next 20 years.

2016 Plan Program Costs

Table 12 shows forecast costs for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 12
2016 Plan Program Costs Estimates
2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Residential	5,987	6,308	4,540	3,048	2,042	21,925
Commercial	1,628	1,906	1,933	2,258	2,301	10,026
Industrial[53]	667	10	10	10	10	707
Total	8,282	8,224	6,483	5,316	4,353	32,658

The Utilities' costs related to programs in the 2016 Plan are forecast to be approximately $32.7 million over the five-year planning period. Forecast changes in program costs primarily reflect the expansion of programs and additional technology offerings anticipated from 2016 to 2018, and the conclusion of certain programs through the planning period.

3.3 Education & Support

The Utilities' customer education and support activities will continue to evolve to support changes in customer energy conservation programs and in the broader conservation market. The Utilities will continue to provide customer support and be responsive to customer expectations. Current activities, including customer outreach events, the takeCHARGE website and partnerships with industry stakeholders will be key elements of customer education.

[53] Forecasted Industrial program costs after 2016 are associated with program promotion and customer engagement. Given the small number of transmission level customers in the province, there is a high degree of uncertainty for participation in the program year to year. The forecasted amounts after 2016 will increase if customers avail of the program for feasibility assessments or incentives for energy efficiency retrofits. Projects will continue to be screened based on cost effectiveness to ensure the program remains above minimum economic thresholds.

The Utilities' educational initiatives will be expanded to include a program promoting mini-split heat pumps. The program components will include financing, education and marketing initiatives directed towards customers, and direct engagement with certified installers and suppliers. A marketing campaign will be launched to raise customer awareness of the benefits of this technology, how to choose a high quality product, as well as the necessity of having the system installed by qualified contractors. The eligibility criteria for on-bill financing of these systems will encourage the installation of high efficiency units, installed by qualified contractors.[54]

The Utilities will continue to build upon their experience offering the takeCHARGE K-I-C Start School Program. Marketing will continue to build awareness of the program amongst school boards and teachers. Teaching aids will be developed and be made available on the takeCHARGE website to assist in furthering conservation education after presentations are conducted. Updates will also be made to strengthen the message of conservation for younger students, and awareness-building contests will be offered for all age groups.

Table 13 shows forecast costs for conservation education and support for the period 2016 to 2020.

Table 13
Conservation Education & Support
Costs 2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Education	770	791	827	851	873	4,112
Support	171	175	181	184	191	902
Total	941	966	1,008	1,035	1,064	5,014

54 Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016.

3.4 Planning & Evaluation

Planning

The 2016 Plan incorporates research and analysis required for the next iteration of multi-year conservation portfolio planning by the Utilities.

Table 14 shows forecast planning costs included in the 2016 Plan.

Table 14
Conservation Planning Costs 2016-2020(F)
($000s)

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Planning	527	596	767	863	644	3,397

Variability in annual planning costs reflects the Utilities' multi-year planning cycle for customer conservation programs.

The Utilities anticipate development of the next multi-year plan for customer energy and demand conservation programming in 2018. Further clarity regarding electrical system cost dynamics is expected to be a factor in the next planning cycle.[55] Further assessment and adjustments to the programming contained in the 2016 Plan may also be required within the next three years as marginal cost forecasts are updated.

Research

The next update of the study of conservation potential in the province is being planned for 2020. In advance of this study, the Utilities will undertake a number of research projects regarding electricity end-use trends and the state of the local market for efficient technologies. For the residential sector, customer surveys will gather details on

[55] An updated marginal cost study is expected to be a key input to the next conservation plan in 2018 and the next CPS in 2019-2020.

the type of electrical equipment that customers have in their homes, as well as their energy-related behaviour and motivation. Research for the commercial sector will include on-site facility audits to collect data on mechanical and electrical equipment being used.

The residential lighting market will be evaluated in 2017 to determine whether the Small Technologies program should continue. This research is expected to include a socket saturation study, with onsite inventories, as well as customer surveying. This will provide the Utilities with detailed data regarding the remaining potential for energy efficient lighting replacements.

Hydro is currently investigating the implementation of an Isolated System Direct Load Control Pilot in the community of Postville, Labrador.[56] The community of Postville is served by diesel generation. The objective of this pilot will be to reduce the peak load in the community and defer investment in electrical system upgrades. The Utilities will also continue to coordinate conservation planning with electrical system planning, and will evaluate potential for conservation initiatives targeted in specific areas or communities that may provide a lower-cost alternative to electrical system upgrades.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project is ongoing and the final report will be submitted to Government by end of March 2016. The results of this pilot project will be used to assess whether this type of technology may be considered as part of future energy conservation programming.

During this planning period, the Utilities will also monitor developments in North American practices for economic evaluation and screening of conservation programs.[57]

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[56] The pilot will involve commercial and residential customers. It will include installing load controllers on hot water tanks, and commercial electric heating circuits, for commercial customers. Load controllers will only be activated during maximum system peak events. The customers that participate will receive incentives such as credits at the local store in Postville.

[57] While reliance on the TRC and PAC tests for primary economic screening is currently the norm in North American jurisdictions, modifications to the TRC methodology are being considered in a number of cases. These modifications primarily involve inclusion of customers' non-energy benefits from efficiency upgrade projects.

Evaluation

The customer program portfolio will continue to be evaluated in terms of its energy savings, market impacts and delivery process effectiveness. Additional review by third party evaluators is expected, reflecting the expanded program portfolio and delivery methods.[58] Program evaluation findings will be used to refine program design and implementation details on an ongoing basis, as well as support further planning.

Specific evaluation objectives in the 2016 Plan are to monitor market saturation of particular technologies as well as cost effectiveness of the programs. For example, the Instant Rebates component of the Small Technologies program will be evaluated and an exit strategy designed based on research into the pace and impact of LED sales growth in the local lighting market.

Similarly, the Utilities will continue to closely monitor the Insulation, Thermostat and HRV programs. These programs have unique challenges and barriers to program participation.[59] Evaluation of these programs will ensure they continue to satisfy cost effectiveness requirements.

In the case of new program introductions, post-implementation evaluations will be conducted within 12 months of program launch to ensure full assessment of program design assumptions, as well as marketing and delivery process effectiveness.

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[58] Evaluation costs are primarily reflected in the costs for each specific program.

[59] For the Insulation and Thermostat Programs, these barriers primarily reflect the inherent difficulty in renovating existing living spaces and the remaining market being increasingly hard-to-reach. For the HRV program, this reflects the low level of customer understanding and slow adoption by the supply chain.

3.5 Costs & Cost Recovery

Table 15 provides a summary of the Utilities' customer energy conservation program and general costs from 2016 through 2020.[60]

Table 15
Conservation Costs
2016 through 2020
($000s)

	2016	2017	2018	2019	2020
Program					
Residential	5,987	6,308	4,540	3,048	2,042
Commercial	1,628	1,906	1,933	2,258	2,301
Industrial	667	10	10	10	10
Total Programs	8,282	8,224	6,483	5,316	4,353
Education	770	791	827	851	873
Support	171	175	181	184	191
Planning	527	596	767	863	644
Total General Costs	1,468	1,562	1,775	1,898	1,708
Total	9,750	9,786	8,257	7,214	6,061

Costs related to the customer energy conservation programs outlined in the 2016 Plan are forecast to be $9.8 million in 2016 and 2017.[61] This increase primarily reflects the addition of a new program, and enhanced program technology offerings. Costs begin to decrease in 2018 from $8.3 million to $6.0 million in 2020. This decrease primarily reflects the conclusion of the Small Technologies program in 2018 and the conclusion of the Benchmarking program in 2019.

60 This cost summary does not include costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management) and costs related to Hydro's interruptible load arrangements.

61 All customer energy conservation programs outlined in the 2016 Plan are cost effective, and are justified on a cost of service basis.

Schedule E provides a summary of forecast energy savings, cost estimates and cost effectiveness analysis results for the programs in the 2016 Plan.[62]

Cost Recovery

The Utilities propose conservation cost recovery based on amortizing customer energy conservation program costs over seven years.[63] The amortization of program costs over a seven-year period is considered appropriate because of the extended nature of the energy savings benefits provided by program technologies.

The Utilities' annually recurring general conservation costs would continue to be expensed as incurred.[64]

4.0 OUTLOOK

The Utilities anticipate significant changes in the electrical system serving the province within the five years considered in this plan. The Muskrat Falls hydroelectric development and related interconnection to the North American grid will affect system operations and costs, as well as customer prices. The next iteration of multi-year conservation program planning is anticipated in 2018, to coincide with these events.

In the interim, the approach outlined in the 2016 Plan will remain flexible to address ongoing changes. The initiatives in the 2016 Plan are cost effective based on current information, and were assessed for sensitivity to changes in system costs. As the Utilities implement the program changes outlined in this Plan, they will continue to evaluate program offerings to ensure they create economic benefits and are responsive to evolving customer expectations and market conditions.

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62 Cost forecasts can be expected to be refined as detailed program design progresses in 2016.

63 Newfoundland Power has used this approach since 2013, based on Order No. P.U. 13 (2013). Hydro has proposed this approach in its ongoing general rate application, and the proposal has been agreed to by the parties to settlement negotiations in that matter.

64 While general customer energy conservation costs provide benefits to customers in terms of information, knowhow and advice, those benefits are not transparently quantifiable in the same manner as program benefits.

With growing customer awareness of conservation, and of the takeCHARGE brand, the Utilities will continue to seek opportunities to partner with complementary organizations and trade allies for customers' advantage. Information sharing and policy coordination with the Province will also continue, primarily through the Office of Climate Change and Energy Efficiency.

Table A-1 shows most recent marginal cost forecast as projected by Newfoundland and Labrador Hydro in February 2015.

Table A-1
Marginal Cost Projection
for the
Island Interconnected System
2015 - 2035

	Energy ($/MWh)	Capacity ($/KW – Yr)
2015	108	51
2016	133	70
2017	134	74
2018	47	98
2019	50	99
2020	54	108
2021	56	112
2022	59	115
2023	62	119
2024	65	123
2025	68	126
2026	70	126
2027	73	125
2028	76	125
2029	78	124
2030	81	124
2031	85	121
2032	88	118
2033	92	116
2034	96	113
2035	100	110

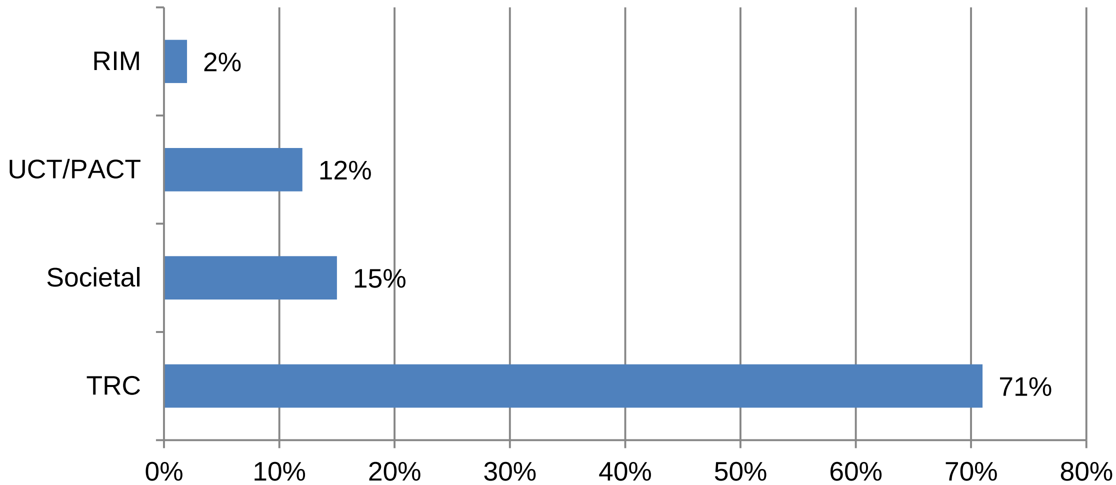
Notes:
1. Modeled as per NERA Economic Consulting marginal cost approach (2006).
2. Fuel costs per NLH corporate assumptions, January 2015.
3. Excludes transmission marginal costs.
4. Projection is at customer bulk delivery point.
5. Island Interconnected costs beyond 2017 reflect opportunity cost as per NERA approach.

Table B-1
Current Canadian
Utility Practice
Economic Evaluation Practices

Province	**Economic Test**				
	TRC	PAC	RIM	PCT[1]	SCT[2]
British Columbia	X[3]				
Ontario	X	X			
Nova Scotia	X	X			
Manitoba[4]	X		X	X	X
Saskatchewan	X	X			
Quebec	X		X[5]		
Prince Edward Island	X	X[6]		X	X[6]

1 Participant Cost Test ("PCT").
2 Societal Cost Test ("SCT").
3 British Columbia uses a modified TRC that includes non-energy benefits that are not traditionally included in the TRC.
4 Manitoba also considers the levelized resource cost, net utility benefit, utility net present value, levelized utility cost, and simple customer payback calculation.
5 Quebec considers the RIM as a secondary test.
6 Prince Edward Island considers the PAC and SCT as secondary tests.

Chart B-1
Current American Utility Practice
Economic Evaluation Practices
(Percent of States)



[7]

n=43

[7] Research conducted by the American Council for an Energy Efficient Economy (February 2012) "A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs".

Insulation Program

Program Description
The objective of this program is to increase the insulation level in residential basements, crawl spaces and attics. Increasing the insulation R-value in a home will result in space heating energy savings. The program components include rebates and financing, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.
Target Market: Residential
This program targets residential customers completing retrofit projects. Changes to the National Building Code of Canada implemented in December 2012 mandated that all new homes install basement insulation and increased the R-Value requirements in the attic. As a result, this program is only offered to existing homes (i.e. connected to the electricity grid before January 1, 2014) to exclude minimum building code compliance in new homes. Eligibility will continue to be limited to electrically-heated homes.
Eligible Measures
Eligible measures in this program include insulation upgrades to basements, crawl spaces and attics. Technical requirements will be approximately aligned with National Building Code of Canada.
Delivery Strategy
Delivery of this program will continue to be bundled with Thermostat, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio. Marketing initiatives include partnering with retailers and trade allies in the renovation industry, and target both do-it-yourself and professional installers. Tools and tactics will include retail point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through mail and online customer applications.

Insulation Program

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the impact on space heating energy, the practical difficulties of renovating an existing living space and a decreasing number of eligible participants. Experience with the existing program has shown participation to be responsive to awareness-building marketing activities.

Incentive Strategy

Incentives for this program include rebates and financing. In August 2014, the rebate structure was simplified and increased. Customers can now get a rebate of 75% of the cost of materials installed in the basement and 50% of the cost of materials in the attic. Rebates amounts are capped at $1,000.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, market saturation and cost effectiveness. A representative sample of installations will be inspected. Formal external evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	1,187	1,207	1,202	1,197	1,223	6,018
Estimated Cumulative Energy Savings (GWh)	30.0	33.1	36.1	38.9	41.8	180
Total Resource Cost						**2.5**

Thermostat Program

Program Description

The objective of this program is to encourage installation of programmable and high performance electronic thermostats in homes. Programmable and high performance electronic thermostats allow customers to better control the temperature of their homes and to set back the temperature during the night or while away. The program components consist of rebates, financing options, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers, including home retrofit and new home construction. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include both programmable and high performance electronic thermostats. All thermostats must have a setting precision of +/- 0.5 degrees Celsius or less.

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the Insulation, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers, electrical contractors, homebuilders and real estate professionals, to educate consumers regarding the energy savings and comfort benefits of programmable & high performance electronic thermostats. Tools and tactics include retail and model home point-of-sale materials, website, tradeshows, community outreach and trade ally activities. Rebates will be processed through mail and online customer applications.

Thermostat Program

Market Considerations

Barriers to installation of programmable and high performance electronic thermostats include lack of awareness of the potential for energy savings, difficulty programming, and reluctance to pay for an electrician to install the thermostats, and a decreasing number of eligible participants.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per high performance electronic thermostat and $10 per programmable thermostat. This continues to reflect incremental cost of the more efficient options. A time limit is no longer required for incentive redemption.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, market saturation, and cost effectiveness, and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	517	555	539	557	552	2,720
Estimated Cumulative Energy Savings (GWh)	9.7	11.1	12.5	13.8	15.2	62
Total Resource Cost						**2.8**

Small Technologies Program

Program Description

The objective of this program is to increase home energy efficiency and awareness by offering instant rebates on a variety of energy efficient technologies as well as online and mail in rebates for eligible appliances and electronics. This program also includes promotional events to raise awareness of the technologies and to engage the public.

Target Market: Residential

This program is marketed toward all residential customers province wide. All customers are eligible to participate regardless of age of home or heat source. A variety of marketing techniques such as TV news sponsorships, print, radio, online, website, as well as social media channels are used to engage customers.

Eligible Measures

Eligible measures in this program will vary over time and will be selected based on cost effectiveness, energy saving potential and market conditions. Instant rebates are available for small energy efficient items such as LEDs and smart power bars, and online and mail in customer applications are required for qualifying models of full-size refrigerators, clothes washers, TVs and full-size Energy Star freezers.

Six new measures will be added to the technology list in 2016. They are:

- Faucet aerators
- Door bottom weather stripping
- Door adhesive
- Window insulation kit
- Electrical outlet gaskets
- Caulking

Small Technologies Program

Delivery Strategy

Partnerships have been made with both chain and independent retailers to offer instant rebates to customers on a number of energy efficient products. Efforts to engage both urban and rural retailers have been made in order to ensure rebated products are available in all areas of the province.

Campaigns are held in the spring and fall each year. During each campaign, the Utilities set up in-store events at the participating locations to raise customer's awareness of the rebates and encourage use of energy efficient products.

Market Considerations

The technologies included in the program do not involve a major renovation. This program will allow the Utilities to reach customers that may not have been able to participate in the other incentive programs.

Incentive Strategy

Incentives for this program include instant rebates for small energy efficient items that will vary by year and campaign. Online and mail in customer applications are available for eligible appliances and electronics. The rebate value will be different for each technology offered, and will reflect incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. Exit interviews will be conducted during selected retail events. Formal evaluations will be conducted after the first year of implementation, and biannually during operation.

It is anticipated that this program will end after 2018. The Utilities expect that LEDs will make up the majority of bulbs that are sold in the province. If this occurs, the economics of the program will no longer be cost effective. The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Small Technologies Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	3,113	2,879	1,578	-	-	7,570
Estimated Cumulative Energy Savings (GWh)	23.8	33.3	38.2	37.4	36.5	169
Total Resource Cost						**1.3**

HRV Program

Program Description

The objective of this program is to increase the installation of higher efficiency Heat Recovery Ventilators (“HRV”). The program components include rebates and financing, and a variety of education and marketing tools.

Target Market

This program targets all residential customers regardless of heat source or age of home. Eligibility is available to all homes that install or replace an HRV.

Eligible Measures

Eligible measures in this program include all HRV models that have an SRE of 70% or more and meet the minimum fan efficacy requirements.

Delivery Strategy

Delivery of this program will be bundled with other takeCHARGE residential programs as part of the overall portfolio. Marketing initiatives include partnering with trade allies in the home building and renovation industry, particularly Heating Refrigeration and Air conditioning Institute certified installers. Tools and tactics include website presence, tradeshows, and trade ally activities. Rebates and financing will be processed through customer application.

Market Considerations

The market includes new construction and existing HRV replacement with an emphasis on existing replacements. Early HRV installations of the 1990s are at or near the end of their useful life, so many of these require replacement.

This program has faced a number of barriers such as understanding of what a HRV is and its purpose in the home, initial cost, and awareness of the benefits of selecting more efficient HRVs.

HRV Program

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $175 for qualifying HRV units. This reflects the incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. This program has experienced challenging barriers to program participation. Attempting to overcome these barriers can be administratively costly and may outweigh the benefits of program delivery. This program will be monitored to ensure that the participation goals are being met in each year to ensure the program remains cost effective. A representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	223	218	232	231	267	1,171
Estimated Cumulative Energy Savings (GWh)	0.7	1.0	1.3	1.6	2.0	7
Total Resource Cost						**1.3**

Benchmarking Program

Program Description
Energy social benchmarking is the analysis of a household's energy consumption and the comparison of its performance with its energy history and that of other similar households. Historic consumption information, tracking over time and comparisons with other households can encourage customers to reduce energy consumption. A printed paper report is delivered to participating customers via mail. These reports include a normative comparison that compares the customer to similar neighbors. The printed Home Energy Report is supplemented by access to an online web portal allowing for increased customer energy usage information and tips and resources to facilitate energy use reduction.
Target Market: Residential
The Benchmarking program is marketed to residential customers across the province. Customers will be selected into the program and can withdraw (opt-out) at any time.
Eligible Measures
A home’s energy use is compared anonymously to the usage patterns of other homes in the vicinity that are of similar size, age, heating type, etc. The Home Energy Report is designed to provide new information to help home owners understand their energy use and find ways to make the home more efficient.
Delivery Strategy
The program is delivered largely by a third party service provider that develops and issues the Home Energy Report and maintains the online web portal. takeCHARGE will oversee all aspects of the program to ensure greater customer insight into their home energy use. The program is available year round and will be supported with takeCHARGE marketing and communication efforts.

Benchmarking Program

Market Considerations

This program will allow the Utilities to reach customers that have not been able to participate in the other incentive programs. It will also allow takeCHARGE actively engage with customers using direct home energy consumption information. This program also allows for the cross promotion of existing takeCHARGE rebate programs as methods to reduce household consumption and to drive participation in these programs.

Incentive Strategy

No monetary incentive will be offered. It has been demonstrated that for this type of program that using social norm comparisons drives the greatest and longest lasting changes to household energy consumption.

Program Monitoring & Evaluation

The program is monitored for participation levels, service quality and cost effectiveness. Formal evaluation will be conducted very two years during operation.

Estimated Costs & Energy Savings

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	530	1,034	989	1,063	-	3,616
Estimated Cumulative Energy Savings (GWh)	0.3	8.0	13.8	15.6	-	38
Total Resource Cost						**1.0**

Mini Split Heat Pump Educational Initiative

Program Description

The objective of the program is to encourage customers to choose high efficiency mini split heat pumps (MSHP), installed by qualified contractors. When installed correctly, a high efficiency MSHP will provide space heating energy savings. The program components include financing, education and marketing initiatives directed towards customers, and direct engagement of certified installers. Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016, however the eligibility criteria for MSHP will be updated to support the uptake of high efficiency units.

Target Market

This program targets residential customers. New home construction and retrofit customers with electric baseboard heat are considered to have the greatest potential for participation, however customer eligibility to participate in financing will not be limited by heating fuel, age or type of dwelling.

Eligible Measures

Financing will now be limited to MSHP with an estimated Heating Seasonal Performance Factor (HSPF) of 9.6 or higher. This is aligned with the minimum HSPF required for certification of units meeting the “ENERGY STAR® Most Efficient 2015” designation. To qualify for financing the installation must be performed by a contractor that has the necessary permits and certification to perform electrical and refrigeration work in the province.

Delivery Strategy

Delivery will be a two pronged approach including marketing to customers and engaging eligible installers.

Marketing initiatives will include information on the takeCHARGE website as well as bill inserts and mass media advertising regarding the benefits of choosing the right heat pump and installer. Installer engagement will include information sessions, contests, and maintaining relationships with qualified installers.

Financing applications will be processed through customer application via the existing customer service channels (online or by phone).

An incentive could not be offered for this program because it does not pass the economic analysis.

Mini Split Heat Pump Educational Initiative

Market Considerations

One of the biggest barriers is a lack of customer awareness and availability of certified installers in rural areas. In order to achieve significant energy savings, the unit must be appropriate for the Newfoundland climate, properly installed and operated.

Other major barriers include identifying what to look for in an installer (i.e. what certification should be required) and difficulty of customers to find qualified installers. The upfront cost of highly efficient units is also a barrier for some customers.

Program Monitoring & Evaluation

This program will be monitored for participation level, and service quality. The criteria for eligible models and installers will also be continually reviewed to ensure the program is promoting units and installers that will provide customers the highest achievable energy savings at a reasonable cost.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	119	100	103	102	104	529

Business Efficiency Program

Program Description

The objective of the Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.

Target Market: Commercial

This program targets business owners and property managers who have an interest in making their businesses more energy efficient. The program includes a custom project approach which appeals primarily to large commercial customers. In 2016, the program will also include rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting, which appeal to small and medium sized customers as well.

Eligible Measures

The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in electrical energy and demand savings. The program excludes alternative energy and fuel switching.

Beginning in 2016 the custom stream of the Business Efficiency Program will also include incentives for demand reduction based on the options available at the customer's facilities as well as the amount of demand they are able to reduce during peak times.

Also beginning in 2016, the existing fluorescent High Bay program and the current Commercial lighting program (including high performance T8 fluorescent lamps and LED exit signs) will become prescriptive rebates under the Business Efficiency Program.[1] Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts are now considered to be the market standard.

The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems and low flow pre-rinse spray valves will be added to the prescriptive list of incentives.

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[1] Prescriptive incentive program are customer energy conservation programs that have per unit rebates for installing certain defined technologies. For example, providing a predefined rebate amount for a LED light bulb;

Business Efficiency Program

Delivery Strategy
The delivery strategy for this program is mainly through individual customer interactions. A walk through audit can help customers identify efficiency opportunities. Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products. The program will also target commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, retail point-of-sale materials, website and advertising in trade publications. Demonstration projects will be selected from program participants.
Market Considerations
Barriers to increased market penetration include initial cost, awareness of the program and available incentives, budget & planning cycles, technical know-how, and customer time constraints.
Incentive Strategy
Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at 10 cents/kWh for first year savings or project demand savings at $100 per kW per month over the December to March period. Demand saving projects require a minimum of 50 kW savings and be sustainable over 5 years. Incentives of up to $50,000 per site help garner interest and lower customer project costs. Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online submissions.
Program Monitoring & Evaluation
The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy or demand savings achieved are consistent with incentives paid.

Business Efficiency Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	1,519	1,791	1,813	2,133	2,171	9,427
Estimated Cumulative Energy Savings (GWh)	18.2	26.9	36.7	47.6	60.2	190
Total Resource Cost						**2.4**

Industrial Energy Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation projects. This program is a custom program to respond to the unique needs of the Newfoundland and Labrador industrial market, rather than a prescriptive technology approach.

Target Market: Industrial

This program targets existing, transmission level, industrial customers served by Newfoundland and Labrador Hydro.

Eligible Measures

Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.

Delivery Strategy

The program is managed internally, with external engineering services used as required. The utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects.

This program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011, and closed to new projects in 2013. The industrial pilot was reviewed in 2014 by an external party for performance; the review indicated the program matched or exceeded performance of comparable industrial CDM programs relative to the size of the industrial sector in the Newfoundland and Labrador market. The program was officially re-launched as an ongoing program in 2015, with the same structure as the pilot program.

Industrial Energy Efficiency Program

Market Considerations

This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources.

The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, budgeting and implementation timelines, and post-installation evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.

Incentive Strategy

Incentives for this program include an initial comprehensive energy audit for the site, funding assistance for feasibility studies, and financial assistance for project implementation based on energy savings.

Program Monitoring & Evaluation

The program will be regularly monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes.

Industrial Energy Efficiency Program

Estimated Costs & Energy Savings[2]						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	667	10	10	10	10	707
Estimated Cumulative Energy Savings (GWh)	30.6	30.6	30.6	30.6	30.6	153
Total Resource Cost						**1.7**

[2] While Customer audits have confirmed that there are several potential projects at Hydro's customers' sites, savings for the Industrial Energy Efficiency Program (IEEP) have only been forecasted for 2016 because there are only five transmission level industrial customers in Newfoundland and Labrador and participation depends on each company's capital budgets and focus for the year. As a result of such a small market and budget considerations, participation is extremely variable from year to year and difficult to forecast. The costs from 2017-2020 are the fixed administration costs associated with program promotion and customer engagement in the IEEP. The majority of costs are incurred after a project is submitted and passes economic screening. Projects for the Industrial EE Program will be evaluated on a yearly basis and projects with a TRC of 1.0 or greater will be completed.

Isolated Business Efficiency Program

Program Description
The objective of the Isolated Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.
Target Market: Commercial
This program targets business owners and property managers in Hydro's isolated diesel and L'Anse au Loup systems who have an interest in making their businesses more energy efficient. The program includes a custom project approach and also rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting.
Eligible Measures
The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in economical electrical energy savings. The program excludes alternative energy and fuel switching. The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, Electrically Commutated Motors for Evaporator fans, Cold climate air source heat pump systems and Low Flow Pre-rinse spray valves will be added to the prescriptive list of incentives.

Isolated Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentive. This allows for a wide range of eligible technologies and projects.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, and a website. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to products and access to specific technical skill sets in the evaluation of projects and technology. Hydro’s program staff will assist in addressing these gaps.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at the lesser of $0.4/kWh for first year savings or 80% of eligible project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online customer applications.

Isolated Business Efficiency Program

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy savings achieved are consistent with incentives paid.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	106	112	117	122	128	585
Estimated Cumulative Energy Savings (GWh)	0.5	0.7	0.8	1.0	1.2	4
Total Resource Cost						**1.6**

Isolated Systems Community Program

Program Description

The objective of this program is to provide a portfolio of technologies and opportunities to help residential and commercial customers in isolated diesel communities save electrical energy and to promote energy efficiency awareness.

Target Market

This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island, in Labrador, and the L'Anse au Loup system.

Eligible Measures

Measures will range from efficient lighting products, hot water saving products, pipe insulation, hot water tank insulation, commercial LED exit signs, and others that may be applicable.

An Appliance Retirement program is being planned for at least one community. Old inefficient appliances will be removed from participating homes and routed for appropriate disposal. This will save energy and money for the homeowner. This component will be evaluated to determine if it is economic to develop into a broader program.

The Isolated systems T12 replacement program will take place in 2-3 Isolated communities. This project will offer, free of charge to commercial customers, the supply and install of new High Performance T8 lamps and ballasts.

Delivery Strategy

Hydro has engaged Summerhill Group to deliver this program. They are using a number of delivery strategies, including hiring and training local representatives, to engage residential and commercial customers. Direct installs will be completed, whereby the customer receives the technology in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability. There is a heavy electric hot water heating penetration and opportunities exist in plug load and behavior based areas.

Commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues; this program will provide the one on one interaction needed to assist these customers. The technologies included in the program do not involve a major renovation. This program will allow the utility to reach customers that may not have been able to participate in the other incentive programs.

Following the 2015 direct install component, information collected in 2014 and 2015 will be used to plan for Isolated Systems Community programming beyond 2017. Costs and energy savings will be estimated once the technologies have been determined.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. A representative sample of direct installs will be surveyed for confirmation of continued installation and use. Formal evaluations will be conducted after each year of operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	415	415	-	-	-	830
Estimated Cumulative Energy Savings (GWh)	5.2	5.5	5.5	5.5	5.5	27
Total Resource Cost						**2.7**

Table D-1
Conservation Programs
Energy Reductions: 2012 – 2015(F)
by Sector
(GWh)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	15.8	20.6	24.0	27.0	87.4
Thermostat Program	4.5	5.8	7.0	8.4	25.7
ENERGY STAR Window Program	6.1	8.6	10.1	10.1	34.9
Coupon Program	0.3	0.3	0.3	0.3	1.2
HRV	0.0	0.0	0.2	0.4	0.6
Small Technologies	0.0	0.0	5.5	14.4	19.9
Isolated Systems Community Program	1.7	2.8	4.1	4.8	13.4
Block Heater Timer Program	-	0.3	0.3	0.3	0.9
Total Residential Portfolio	**28.4**	**38.4**	**51.5**	**65.7**	**184.0**
Commercial					
Lighting Rebate Program	3.3	3.9	5.8	6.5	19.5
BEP	-	-	0.6	4.5	5.1
Isolated Systems Business Efficiency Program	-	-	0.1	0.4	0.5
Total Commercial Portfolio	**3.3**	**3.9**	**6.5**	**11.4**	**25.1**
Industrial					
Industrial Energy Efficiency Program	3.3	3.3	25.6	25.6	57.8
Total Portfolio	**35.0**	**45.6**	**83.6**	**102.7**	**266.9**

Table D-2
Conservation Programs
Program Costs: 2012 – 2015(F)
by Sector
($000s)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	882	1,092	796	1,039	3,809
Thermostat Program	492	253	227	454	1,426
ENERGY STAR Window Program	1,173	1,634	698	7	3,512
Coupon Program	-	-	-	-	-
HRV	-	59	56	225	340
Small Technologies	-	4	1,877	2,884	4,765
Isolated Systems Community Program	858	871	615	579	2923
Block Heater Timer Program	31	8	8	-	47
Total Residential Portfolio	**3,436**	**3,921**	**4,277**	**5,188**	**16,822**
Commercial					
Lighting Rebate Program	121	128	373	790	1,412
BEP	-	112	457	532	1,101
Isolated Systems Business Efficiency Program	93	115	96	66	370
Total Commercial Portfolio	**214**	**355**	**926**	**1,388**	**2,883**
Industrial					
Industrial Energy Efficiency Program	173	89	1,244	19	1,525
Total Portfolio	**3,823**	**4,365**	**6,447**	**6,595**	**21,230**

Table E-1
Conservation Programs
Energy Reduction Estimates: 2016 – 2020
by Sector
(GWh)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	30.0	33.1	36.1	38.9	41.8	179.9
Thermostat Program	9.7	11.1	12.5	13.8	15.2	62.3
ENERGY STAR Window Program	10.1	10.1	10.1	10.1	10.1	50.5
Coupon Program	0.3	0.3	0.3	0.3	0.3	1.5
Isolated Systems Community Program	5.2	5.5	5.5	5.5	5.5	27.2
Small Technology Program	23.8	33.3	38.2	37.4	36.5	169.1
HRV Program	0.7	1.0	1.3	1.6	2.0	6.6
Benchmarking	0.3	8.0	13.8	15.6	-	37.7
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**80.4**	**102.7**	**118.1**	**123.5**	**111.7**	**536.4**
Commercial						
Isolated Systems Business Efficiency Program	0.5	0.7	0.8	1.0	1.2	4.3
Business Efficiency Program	18.2	26.9	36.7	47.6	60.2	189.6
Total Commercial Portfolio	**18.7**	**27.6**	**37.5**	**48.6**	**61.4**	**193.8**
Industrial						
Industrial Energy Efficiency Program	30.6	30.6	30.6	30.6	30.6	153.0
Total Portfolio	**129.7**	**160.9**	**186.2**	**202.7**	**203.7**	**883.2**

Table E-2
Conservation Programs
Program Cost Estimates: 2016 – 2020
by Sector
($000s)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	1,189	1,207	1,202	1,197	1,223	6,018
Thermostat Program	517	555	539	557	552	2,720
Isolated Systems Community Program	415	415	-	-	-	830
Small Technology Program	3,113	2,879	1,578	-	-	7,570
HRV Program	223	218	232	231	267	1,171
Benchmarking Program	530	1,034	989	1,063	-	3,616
Total Residential Portfolio	**5,987**	**6,308**	**4,540**	**3,048**	**2,042**	**21,925**
Commercial						
Isolated Systems Business Efficiency Program	106	112	117	122	128	585
Business Efficiency Program	1,522	1,794	1,816	2,136	2,173	9,441
Total Commercial Portfolio	**1,628**	**1,906**	**1,933**	**2,258**	**2,301**	**10,026**
Industrial						
Industrial Energy Efficiency Program	667	10	10	10	10	707
Total Programs Portfolio	**8,282**	**8,224**	**6,483**	**5,316**	**4,353**	**32,658**

Table E-3
Conservation Programs
Total Resource Cost Test Results
by Sector

	TRC Results
Residential	
Insulation Program	2.5
Thermostat Program	2.8
Isolated Systems Community Program	2.7
Small Technology Program	1.3
HRV Program	1.3
Benchmarking	1.0
Commercial	
Isolated Systems Business Efficiency Program	1.6
Business Efficiency Program	2.4
Industrial	
Industrial Energy Efficiency Program	1.7

Labour Forecast 2015-2017

March 2016

Table of Contents

1.0. BACKGROUND

This report contains detailed information concerning the method used by Newfoundland Power to forecast its test year full-time equivalents ("FTEs") and labour expense. In addition, it explains the assumptions used to determine forecast vacancies.[1]

Newfoundland Power's current labour requirements will tend to be consistent from year to year.[2] In managing its workforce, the Company matches overall capacity and capability with anticipated work requirements.

The method used to forecast labour requirements and FTEs for a test year reflects this basic workforce management philosophy.

2.0 FORECASTING WORKFORCE REQUIREMENTS

Forecasting the Work
The starting point in forecasting Newfoundland Power's annual labour requirements is the Company's annual capital and operational work requirements.[3]

Annual capital work requirements are principally based on specific expenditures required to replace deteriorated, defective or obsolete equipment, and to serve forecast customer and sales growth.[4]

Annual operating work requirements are principally focused on the maintenance and operation of the electrical system, response to customer inquiries, and commercial functions such as meter reading and billing.[5] These requirements tend to be stable over time. For this reason, historical expenditure, adjusted for changes in operating requirements, is the foundation for forecasting annual operating work requirements.

Workforce Options
Having determined the annual work requirements, the Company considers the amount of internal labour available to meet these requirements.

The Company's annual work requirements are met using a combination of regular employees, temporary employees and contractors. This approach permits Newfoundland Power to maintain

[1] In Order No. P. U. 32 (2007), the Board directed Newfoundland Power to include this information as part of its next general rate application.
[2] For the period from 2014 through 2017F, Newfoundland Power's workforce is forecast to decrease by 3.1% or 20.7 FTEs.
[3] In addition to capital and operating requirements, there are labour requirements for rechargeable and recoverable items. These include labour associated with material handling (i.e., stores) and vehicle service centre labour costs, which are recharged as overheads on operating and capital work. It also includes customer jobbing, third party provisioning services and inter-affiliate labour charges.
[4] These requirements are approved by the Board on a prospective basis each year through the Company's capital budget applications.
[5] Annual operating work requirements also include general support functions, such as information services, human resources and finance.

a highly skilled core workforce and reasonable flexibility to respond to variations in work requirements on a least cost basis.

Annual capital work requirements tend to be met by a combination of the Company's internal workforce and contractors. This is partly attributable to the variable nature of these work requirements.[6] It is also consistent with the deployment of the Company's internal workforce.[7]

Annual operating work requirements tend to be met by the Company's internal workforce.[8] This is partly attributable to stability of these work requirements on a year over year basis. It is also partly attributable to the specialized nature of these work requirements.[9]

Vacancy Assumptions

In determining the internal workforce available to execute the annual capital and operating work requirements, the Company assesses its internal workforce on an FTE basis.[10]

The actual FTEs for the most recently completed year reflect the impact of all vacancies in that year. In other words, the FTEs for the most recently completed year include only the actual paid hours *worked in that year*. For this reason, the FTEs for the most recently completed year are the basis Newfoundland Power uses for forecasting FTEs.

In forecasting FTEs, Newfoundland Power will make adjustments for future years. This is done to better predict availability of the internal workforce to meet work requirements. This, in turn, permits the Company to assess its workforce options.[11]

The typical adjustments to an FTE forecast include anticipated retirements, leaves of absence[12],

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6 The specific requirements of annual capital work have different labour requirements depending on the projects involved. For example, penstock construction requires riggers and welders. However, electrical system operations have no ongoing requirement for those skilled trades. Accordingly, such work would be performed by contractors.

7 Deployment of Powerline Technicians ("PLT") is an example of this. PLTs perform a mixture of operating and capital maintenance. In winter, Newfoundland Power's service obligations practically require it to have PLTs deployed across its service territory in sufficient numbers to respond to seasonal electrical system trouble. In the construction season, PLTs can be deployed to construction sites across the province as necessary.

8 Approximately 7% of Newfoundland Power's internal workforce is temporary labour. Use of temporary labour provides operating flexibility.

9 Specialized knowledge of electrical system operations is required for a great deal of operational work and is a core competency of Newfoundland Power's workforce. This specialized knowledge is typically not required to perform much of the capital work requirements of the Company.

10 Newfoundland Power calculates FTEs based on employee hours worked divided by total working hours in a year. For approximately 58% of the workforce, the total working hours in a year are 2,080. For the remainder, the total working hours in a year are 1,950. The FTE calculation reflects only hours worked and permits a better matching of work requirements to available workforce options than forecasting positions and applying a vacancy allowance.

11 From a practical perspective, forecast FTEs will become the basis for the Company's determination of hiring requirements and contract labour requirements.

12 Leaves of absence include maternity leave, absences due to long-term disability or workplace injury, education leave and other leaves of absence approved by the Company.

terminations and new hires. These adjustments reflect the timing and salary impacts of workforce changes. For example, in the case of retirements, differences in salary and timing gaps or overlaps among employees entering and leaving the workforce can be incorporated into the adjustments.[13] A similar approach is used for employees commencing leaves of absence and those returning from leave.

These adjustments are fully reflected in both forecast FTEs and labour costs. The forecast FTEs are a tool to assess the *internal* workforce available to meet overall work requirements. The forecast labour costs reflect salary and timing differences associated with changes in the internal workforce.

Newfoundland Power's assessment of its internal workforce is undertaken in the context of its total forecast labour requirements. These total labour requirements are a function of forecast capital and operating work requirements.[14]

Reconciling Work and Labour

Newfoundland Power's total labour requirements for 2015 were $77.5 million. For the 2016 and 2017 test year, the total forecast labour requirements are $76.5 million and $77.0 million respectively. These requirements reflect forecast capital and operational work requirements for each year.

The Company's internal labour expense for 2015 was $63.2 million. For 2016 and 2017, forecast internal labour expense is $65.7 million and $66.9 million respectively. The difference between the total forecast labour requirement and the Company's internal labour available will be addressed using contract labour.

3.0 2015 to 2017 LABOUR FORECASTS

2015 FTEs and Internal Labour Expense

In 2015 the year-end FTEs, based on the *actual hours worked*, was 653.0. The associated internal labour expense was $63.2 million.

< >

Schedule A presents the detailed breakdown of < > internal labour expense and FTEs for 2015.

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13 The time period between employees entering and leaving the workforce can be either negative or positive. For example, if a replacement employee arrives before a senior employee retires to avail of a training opportunity, this will increase the FTE count and labour expense. However, if there is a period of time a position remains vacant awaiting a replacement employee to enter the workforce, this will decrease the FTE count and labour expense.

14 The loss of an employee in any year will typically result in the work being performed by temporary labour or a contractor. It is unusual that either capital or operating work would not be performed in any given year due to the loss of an employee.

2016 FTEs and Internal Labour Expense
The 2016 FTEs and internal labour expense were calculated using the actual 2015 FTE results as the starting point. To account for the impact of inflation, the 2015 internal labour expense is adjusted to reflect salary increases applicable to 2016.

The test year labour forecast reflects 39 projected retirements, with 30 of these employees to be replaced, plus 13 new hires. The new hires will meet increased requirements for Powerline Technician Apprentices and additional resources for expansion of customer energy conservation programming. In addition, the 2016 FTEs and internal labour expense includes employees working a partial year in 2015 who are anticipated to be in the workforce for a full year in 2016, offset by employees who left in 2015.

Schedule B presents the detailed breakdown of forecast internal labour expense and FTEs for 2016.

2017 FTEs and Internal Labour Expense
The 2017 FTEs and internal labour expense were calculated using the 2016 forecast as the starting point. To account for the impact of inflation, the 2016 internal labour expense is adjusted to reflect salary increases applicable to 2017.

The test year labour forecast reflects an overall reduction of 13.0 FTEs primarily due to completion of the AMR project.

Schedule C presents the detailed breakdown of forecast internal labour expense and FTEs for 2017.

Schedule A
2015 Internal Labour

	Labour Expense ($000s)	FTEs	Notes
2014 Workforce			
Operating	32,114		1
Capital	26,021		
Rechargeable & Recoverable	4,374		
Total	**62,509**	**664.8**	2
2015 Salary Increase	2,188		3
Adjustments for 2015			
2015 Retirements			
Employee Retirement[15]	(2,644)	(23.4)	4
Retirement Replacement	968	9.4	5
2015 Leaves of Absence			
Employees Taking Leaves	(542)	(5.9)	6
Employees Returning from Leaves	318	3.5	7
Terminations[16]	(366)	(3.8)	8
New Hires	538	5.6	9
Partial Year Adjustments[17]	196	2.8	10
Loading Impact shift to capital/R&R			
2015 Adjusted Workforce	**63,165**	**653.0**	11
2015 < > Workforce			
Operating	31,532		12
Capital	26,936		
Rechargeable & Recoverable	4,697		
Total	**63,165**		13

15 Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service, or have expressed interest in retiring prior to reaching this milestone.

16 Terminations include both voluntary and non-voluntary termination of employment with the Company.

17 Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2015. These employees would not have accounted for full annual salaries in the 2014 labour expense, nor would they have accounted for full FTEs in 2014. These adjustments also include employees who left the Company in 2014. These employees do not account for full annual salaries in the 2015 labour expense, nor would they account for full FTEs in 2015.

Notes for Schedule A

No.	Description
1	The actual year end operating labour cost for 2014. It includes the impact of all retirements, leaves of absence, terminations and new hires experienced in 2014.
2	The 2014 actual year end FTEs count is reflective of the 2014 work requirement. It reflects the impacts, including timing impacts, of all retirements, leaves of absence, terminations and new hires of regular and temporary employees experienced in 2014. Total labour expense includes overhead loading for vehicle expenses.
3	The 2015 salary increase is based upon a weighted average salary increase of 3.5%.
4	In 2015, there were 35 employee retirements. The 2015 labour reduction for retirements was $2,644,389. Due to the timing of the retirements, the 2015 reduction in FTEs was 23.4.
5	15 of the retiring employees were replaced in 2015. A combination of lower salary and the timing of replacement hires, resulted in a $968,351 labour cost and 9.4 FTE increase for 2015.
6	In 2015, 12 employees commenced leaves of absences, consisting of 5 maternity leaves and 7 long-term disability absences. The 2015 labour reduction for leaves was $542,015 with a corresponding FTE reduction of 5.9.
7	In 2015, the Company had 8 employees returning from various forms of leave. This includes 1 employee on maternity leave, 1 on workers compensation, and 6 on long-term disability. The 2015 labour increase for leaves was $318, 314 with a corresponding FTE increase of 3.5.
8	In 2015, employment was terminated for 5 employees. This includes 2 deceased employees. The 2015 labour reduction for terminations was $365,892 with a corresponding FTE reduction of 3.8.
9	In 2015 there were 12 regular new hires. These new hires do not include replacement employees associated with retirements The 2015 labour increase for new hires was $538,257, with a corresponding FTE increase of 5.6.
10	The 2015 labour increase for partial year adjustments was $196,000, with a corresponding FTE increase of 2.8.
11	The 2015 < > FTE count.
12	The 2015 < > operating labour cost, excluding overtime.
13	Total labour expense includes overhead loading for vehicle expenses.

Schedule B
2016 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2015 Forecast Workforce			
Operating	31,532		1
Capital	26,936		
Rechargeable & Recoverable	4,697		
Total	**63,165**	**653.0**	2
2016 Salary Increase	**2,053**		3
Extra Day in 2016	244		4
Adjustments for 2016			
2016 Retirements			
Employee Retirement[18]	(1,791)	(14.5)	5
Retirement Replacement	1,828	15.3	6
2016 Leaves of Absence			
Employees Taking Leaves	(377)	(3.4)	7
Employees Returning from Leaves	595	6.0	8
Terminations[19]	(441)	(5.1)	9
New Hires	678	8.0	10
Partial Year Adjustments[20]	(221)	(2.2)	11
2016 Adjusted Workforce	**65,733**	**657.1**	12
2016 Forecast Workforce			
Operating	32,298		13
Capital	28,361		
Rechargeable & Recoverable	5,074		
Total	**65,733**		14

[18] Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service.
[19] Terminations include both voluntary and non-voluntary termination of employment with the Company.
[20] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2016. These employees would not have accounted for full annual salaries in the 2015 labour expense, nor would they have accounted for full FTEs in 2015. These adjustments also include employees who left the Company in 2015. These employees do not account for full annual salaries in the 2016 labour expense, nor would they account for full FTEs in 2016.

Notes for Schedule B

No.	Description
1	The < > operating labour cost for 2015. It includes the impact of all retirements, leaves of absence, terminations and new hires < > for 2015, and reflected in the adjustments set out in Schedule A.
2	The 2015 < > FTEs are reflective of the < > 2015 work requirement. It reflects the detailed impact, including timing, of all retirements, leaves of absence, terminations and new hires of regular and temporary employees < > in 2015, and reflected in Schedule A. Total labour expense includes overhead loading for vehicle expenses.
3	The 2016 salary increase is based upon a weighted average salary increase of 3.25%.
4	In 2016, there are 262 working days versus 261 working days in 2015, resulting in a labour increase of $244,000.
5	In 2016, there are 39 employees expected to retire. The 2016 labour reduction for retirement is $1,790,935. The 2016 reduction in FTEs of 14.5 reflects the timing of the forecast retirements.
6	30 of the retiring employees will be replaced in 2016 which results in $1,828,324 labour cost and an 15.3 FTE increase for 2016.
7	In 2016, the Company forecasts 8 employees taking leaves of absence based upon recent experience. The 2016 labour reduction for leaves is $376,629 with a corresponding FTE reduction of 3.4.
8	In 2016, the Company forecasts 9 employees returning from various forms of leave. These include 5 employees on maternity leave and 4 employees on long-term disability. The 2016 labour increase for leaves is $594,946, with a corresponding FTE increase of 6.0.
9	In 2016, the Company forecasts 4 employees terminating their employment based upon recent experience as well as the 2016 impact of Automatic Meter Reading (AMR) strategy. The 2016 labour reduction for terminations is $440,553, and a corresponding FTE reduction of 5.1.
10	In 2016, the Company forecasts 3 new hires related to customer energy conservation , 9 PLT Apprentices and 1 program analyst. These new hires do not include replacement employees associated with retirements. The 2016 labour increase for new hires is $677,565, with a corresponding FTE increase of 8.0.
11	The 2016 labour increase for partial year adjustments is a decrease of $221,000 with a corresponding FTE decrease of 2.2.
12	The 2016 forecast FTE count.
13	The 2016 forecast operating labour cost excluding overtime.
14	Total labour expense includes overhead loading for vehicle expenses.

Schedule C
2017 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2016 Forecast Workforce			
Operating	32,298		1
Capital	28,361		
Rechargeable & Recoverable	5,074		
Total	**65,733**	**657.1**	2
2017 Salary Increase	**2,136**		3
1 Less day in 2017	(253)		
Adjustments for 2017			
2017 Retirements			
Employee Retirement[21]	(1,004)	(9.2)	4
Retirement Replacement	872	7.6	5
2017 Leaves of Absence			
Employees Taking Leaves	(412)	(3.7)	6
Employees Returning from Leaves	302	2.8	7
Terminations[22]	(429)	(4.7)	8
New Hires	240	3.0	9
Partial Year Adjustments[23]	(564)	(8.8)	10
2017 Adjusted Workforce	**66,621**	**644.1**	11
2017 Forecast Workforce			
Operating	32,841		12
Capital	28,579		
Rechargeable & Recoverable	5,201		
Total	**66,621**		13

[21] Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service.
[22] Terminations include both voluntary and non-voluntary termination of employment with the Company.
[23] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2017. These employees would not have accounted for full annual salaries in the 2016 labour expense, nor would they have accounted for full FTEs in 2016.

Notes for Schedule C

No.	Description
1	The forecast operating labour cost for 2016. It includes the impact of all retirements, leaves of absence, terminations and new hires anticipated for 2016, and reflected in the adjustments set out in Schedule B.
2	The 2016 forecast FTEs are reflective of the forecast 2016 work requirement. It reflects the detailed impact, including timing, of all retirements, leaves of absence, terminations and new hires of regular and temporary employees anticipated in 2016, and reflected in Schedule B. Total labour expense includes overhead loading for vehicle expenses.
3	The 2017 salary increase is based upon a weighted average salary increase of 3.25%.
4	In 2017, there are 23 employees expected to retire. The 2017 labour reduction for retirement is $1,004,377. The 2017 reduction in FTEs of 9.2 reflects the timing of the forecast retirements.
5	19 of the retiring employees will be replaced in 2017. A combination of lower salary and the timing of replacement hires, results in $872,366 labour cost and a 7.6 FTE increase.
6	In 2017, the Company forecasts 8 employees taking leaves of absence based upon recent experience. The 2017 labour reduction for leaves is $411,760 with a corresponding FTE reduction of 3.7.
7	In 2017, the Company forecasts 5 employees returning from various forms of leave. The 2017 labour increase for leaves is $302,267, with a corresponding FTE increase of 2.8.
8	In 2017, the Company forecasts 4 employees terminating their employment based upon recent experience as well as the 2017 impact of AMR strategy. The 2017 labour reduction for terminations is $429,035, and a corresponding FTE reduction of 4.7.
9	In 2017, the Company forecasts 6 PLT Apprentices hires. These new hires do not include replacement employees associated with retirements. The 2017 labour increase for new hires is $240,443, with a corresponding FTE increase of 3.0.
10	The 2017 labour increase for partial year adjustments is a decrease of $564,000, with a corresponding FTE decrease of 8.8.
11	The 2017 forecast FTE count.
12	The 2017 forecast operating labour cost excluding overtime.
13	Total labour expense includes overhead loading for vehicle expenses.

2016 and 2017 Rate Base Allowances

March 2016

Table of Contents

1.0 INTRODUCTION

It is mainstream practice for a utility's rate base to include allowances for (i) funds used during construction ("AFUDC"), (ii) cash working capital ("CWC Allowance"), and (iii) materials and supplies ("Materials Allowance").[1]

For this Application, Newfoundland Power has reviewed its CWC Allowance and Materials Allowance to reflect any changes that have occurred since the last detailed reviews.

The CWC Allowance calculated for 2016 and 2017 is $8,306,000 and $8,322,000 respectively. This is approximately 1.3% of forecast 2016 and 1.4% of forecast 2017 regulated cash operating expenses.[2]

The Materials Allowance calculated for 2016 and 2017 is $6,485,000 and $6,788,000 respectively. This reflects a revised expansion factor for the calculation of expansion inventory of 20.61%.[3]

2.0 CWC ALLOWANCE

2.1 Methodology

The inclusion of a CWC Allowance in rate base, and the use of a lead/lag study to calculate the allowance are accepted practices for regulated utilities. A lead/lag study recognizes that the utility provides service to customers prior to the receipt of payment for that service. It also recognizes that there is generally a delay in payment by the utility for the goods and services it acquires.

A lead/lag study analyzes transactions over a period of time to determine (i) for each revenue stream, the average number of lag days between the provision of service to customers and the receipt of payment for that service from customers (the revenue lags), and (ii) for each expense, the average number of lag days between the provision of service to customers and the date that the utility pays for the goods and services that it acquires to provide service (the expense lags). The difference between these two lags is referred to as a net lag or net lead.

A net lag occurs when the payment of an expense precedes the collection of its related revenue stream. In this situation, the utility's investors must supply capital to finance the expense until receipt of the related revenues. A net lead position occurs in the opposite situation with the opposite impact.

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1 Newfoundland and Labrador Hydro's rate base includes these 3 allowances in addition to a fuel inventory allowance.

2 This compares to $6,605,000 and $6,384,000 or 1.7% of forecast regulated cash operating expenses, used in 2013 and 2014. Although the percentage has dropped since 2013 and 2014, the change in HST Adjustment has led to an increase in the CWC Allowance for 2016 and 2017. See Section 2.2 for further detail.

3 This compares with a materials allowance of $5,140,000 and $5,247,000 which included an expansion factor of 22.53% used in 2013 and 2014.

Once the revenue lags and expense lags are determined, the calculation of the CWC Allowance involves the following steps:

1. Weight each revenue lag by its related revenue stream to calculate the total weighted average revenue lag.
2. Weight each expense lag by its related expense to calculate the total weighted average expense lag.
3. Subtract the weighted average expense lag from the weighted average revenue lag and divide the result by 365 days. This is the CWC factor.[4]
4. Multiply the CWC factor by the total regulated expenses to calculate the average amount of working capital required to finance the expenses.
5. Add to the amount determined in step 4 the net impact of the collection and payment of the harmonized sales tax ("HST") on working capital. The result is the CWC Allowance.

The CWC Allowance determined via a lead/lag study is indicative of a utility's average daily working capital requirements.

2.2 Leads & Lags : 2016 & 2017

General

In determining its 2016 and 2017 forecast cash working capital allowance, each of the individual revenue and expense lags were reviewed and updated to reflect any observed changes in revenue/expense streams. In addition, the timing and remittance of HST payments were also reviewed and updated.

Newfoundland Power's lead/lag study is based on 2014 actual data as it represents the most recent historical results available at the time.

Compared to 2013, there have been two notable changes to the calculation of Newfoundland Power's cash working capital allowance. These changes are related to corporate income taxes and HST rebates. The timing and amount of payments for the Company's 2014 corporate income taxes has increased the expense lag over the 2013 lead/lag study. Effective July 1, 2015, the Government of Newfoundland and Labrador ended a residential energy rebate equivalent to the provincial portion (8 percent) of the 13 percent HST.

Through the lead/lag study, Newfoundland Power has determined (i) its revenue lags, (ii) its expense lags and (iii) the leads/lags associated with HST for 2016 and 2017 test years. Together, these leads and lags form the basis for the 2016/2017 CWC Allowance.

The leads and lags calculated have been applied to the Company's forecast 2016 and 2017 test year data to calculate the proposed CWC Allowance. These calculations are summarized on the following page.

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[4] In a net lag situation, the CWC factor represents the percentage of expenses that has to be financed by the utility's investors during the year. Investor funding is necessitated by the fact that the cash outflows for expenses preceded the cash inflows for the related revenues. The CWC Allowance for a net lag is added to the rate base in order to provide a utility with a reasonable opportunity to recover the cost of the related investor supplied funding. In a net lead situation, the opposite is true.

Revenue Lag

The revenue lag was calculated by analyzing all of the Company's revenue streams and accounts receivable for 2014 to determine the average number of lag days between when service is provided to customers and when payment for the service is received from customers. Newfoundland Power has two distinct revenue streams which can broadly be described as "consumer billings" and "other billings."

Consumer billings included in the calculation of the CWC Allowance are composed of (i) electricity billings and related municipal tax billings, (ii) forfeited discounts and interest earned on overdue accounts receivable, (iii) ancillary items such as connection/reconnection fees, and (iv) HST.

Other billings are composed of pole rentals, work done by the Company for others, and various miscellaneous revenues and HST.

Revenue lags were calculated for consumer billings and other billings. These were weighted, based on the percentage of the total 2016 and 2017 forecast billings represented by each, to produce a total weighted average revenue lag of 37.76 days for 2016 and 37.73 days for 2017.[5] These are set out in Schedule 1 of Appendices A and B.

Expense Lag

The expense lag was calculated by analyzing each of the Company's cash operating expenses for 2014 to determine the average number of lag days between when service is provided to customers and when payment is made for the goods and services that are acquired to provide service.

The calculated expense lag of each cash operating expense was weighted based on the percentage of the total 2016 and 2017 forecast cash operating expenses represented by each to produce a total weighted average expense lag for the Company of 32.86 days for 2016 and 32.80 days for 2017.[6] These are set out in Schedule 2 of Appendices A and B.

For 2016 and 2017, the expense lag associated with the payment of corporate income taxes has changed in comparison to the lag included in the 2014 test year cash working capital study. In determining the expense lag for corporate income taxes, the actual 2014 tax payments were analyzed and weighted against the average service lag. It is normal practice that a final tax payment is made to settle the tax account once the corporate tax return is finalized. For the 2014 tax year, a final tax payment was made on March 2, 2015 of approximately $6,700,000.[7]

5 By comparison, the revenue lag included in the 2013 and 2014 test year cash working capital study was 36.92 days for 2013 and 36.74 days for 2014.

6 By comparison, the expense lag included in the 2013 and 2014 test year cash working capital study was 30.61 days for 2013 and 30.57 days for 2014.

7 By comparison, the final tax payment included in the analysis for the 2013 and 2014 test year cash working capital study was approximately $1.9 million.

This effectively increased the expense lag for corporate income taxes in 2014 and contributed to an increase in the 2016 and 2017 forecast expense lag over the 2013/2014 test years.[8]

HST Adjustment

HST is collected from customers on certain billed revenues and paid to suppliers on certain expenses and capitalized costs. The difference between HST collections and HST payments in each month is settled with government on the last day of the month that follows the month in which the HST was billed or, if that day is not a business day, on the first business day thereafter.

On average, HST on most of Newfoundland Power's billings is collected from customers before it is settled with government. The Company has use of these funds between the collection date and the settlement date. This serves to reduce the necessary CWC Allowance.

On average, HST billed by Newfoundland Power's suppliers is paid to those suppliers before it is settled with government. The Company has to finance the HST between the payment date and the settlement date. This serves to increase the necessary CWC Allowance.

In 2011, the Government of Newfoundland and Labrador implemented a residential energy rebate equivalent to the provincial portion (8 percent) of the 13 percent HST. Effective July 1, 2015, this rebate ended. Prior to this development, Newfoundland Power received a HST rebate from the Government of Newfoundland and Labrador approximately 40 days before the HST was required to be paid. As a result of the end of the rebate program, the weighted average lead with respect to HST on consumer billings has decreased from 34.6 days in 2013 and 2014 to approximately 24.3 days in both 2016 and 2017.[9]

The net HST impact is an increase in the Company's proposed 2016 and 2017 test year CWC Allowance of $944,000 in 2016 and $835,000 in 2017. The 2013 test year HST adjustment of ($1,986,000) and 2014 HST adjustment of ($2,180,000) decreased the 2013 and 2014 CWC allowance. The change in HST adjustments primarily reflects the conclusion of the provincial residential energy HST rebate in 2015.[10] Newfoundland Power's 2016 and 2017 HST adjustments are set out in Schedule 3 of Appendices A and B.

2.3 Test Year CWC Allowance: 2016 & 2017

Newfoundland Power's proposed 2016 and 2017 test year CWC Allowance based on the calculated revenue lag, expense lag and HST adjustment is $8,306,000 in 2016 and $8,322,000 in 2017. These are set out in Schedule 4 of Appendices A and B.[11]

8 The 2013/2014 test year weighted average expense lags related to corporate income taxes was 1.50 and 1.51. The weighted average expense lag for corporate income taxes is 2.97 in 2016 and 3.16 in 2017. The increase in the expense lag means that Newfoundland Power has use of these funds for a longer period of time thereby reducing the financing requirements for corporate income taxes.

9 The decrease in the lead time for the payment of HST reflects the fact that the Company will no longer receive a rebate from the Government of Newfoundland and Labrador in advance of the required HST payment.

10 < > HST is forecast at 13% for 2016 and 2017.

11 By comparison, the cash working capital allowance included in the 2013 test year was $6.6 million, and $6.4 million in the 2014 test year.

The effect of the proposed 2016 and 2017 CWC Allowance is to provide Newfoundland Power with a reasonable opportunity to recover its cost of providing regulated service.

3.0 MATERIALS & SUPPLIES ALLOWANCE

The inclusion of a Materials Allowance in rate base is an accepted practice for regulated utilities. The Materials Allowance provides regulated utilities with a means to reasonably recover the cost of financing inventories. In determining the amounts of materials and supplies to include in rate base, Newfoundland Power is required to exclude that portion that it identifies as expansion inventory.[12]

In Order No. P.U. 13 (2013), the Board approved rate base calculations of Newfoundland Power's rate base including a Materials Allowance based upon (i) a thirteen month average versus a simple average and (ii) expansion inventory of 22.53%.[13]

For the 2016/2017 General Rate Application, Newfoundland Power has revised its expansion factor used in the calculation of the Materials Allowance based on a review of actual inventories in 2014 used for expansion projects. The revised expansion factor for the 2016 and 2017 test year is 20.61% versus 22.53% calculated for the 2014 test year.

[12] In Order No. P.U. 1 (1974), Newfoundland Power was directed by the Board to identify and exclude from rate base all inventories and supplies related to expansion of the electrical system. Essentially, the Board noted that materials and supplies related to future expansion were similar in nature to work in progress in that they are held to provide future service. Similar to the treatment of work in progress, materials and supplies related to expansion are excluded in the calculation of rate base.

[13] Newfoundland Power's average rate base for the 2014 test year was approved by the Board in Order No. P.U. 23 (2013) and included the Company's revised calculation of its materials and supplies allowance.

Newfoundland Power Inc.

2016 Forecast Revenue Lag

Cash Inflows	2016 Forecast [1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
Consumer Billings	679,772	99.49%	36.56	36.37
Other Billings	3,455	0.51%	271.00	1.38
Total	683,227	100.00%		**37.75**

[1] Reconciliation to 2016 Revenue Requirement ($000s) :

Total Billings Above	683,227
Rate Stabilization Adjustments	6,292
Municipal Tax Billings	(16,423)
Billings Recorded as Revenue	673,096
Revenue excluded from CWC Allowance	
Revenue Accrual (non-cash)	871
Equity Portion of AFUDC	482
Total Revenue	674,449
Deduct: Other Revenue	(5,289)
2016 Revenue Requirement from Rates	669,160

Newfoundland Power Inc.

2016 Forecast Expense Lag

		2016 Forcast	Adjustments[1] ($000s)	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
	Operating Expenses						
1	Labour	36,898		36,898	6.70%	37.15	2.49
2	Vehicle Expenses	1,698		1,698	0.31%	45.21	0.14
3	Operating Materials	1,641		1,641	0.30%	45.21	0.13
4	Inter-Company Charges	2,197		2,197	0.40%	45.21	0.18
5	Plants,Subs,System Ops & Buildings	2,269		2,269	0.41%	45.21	0.19
6	Travel	1,237		1,237	0.22%	45.21	0.10
7	Tools and Clothing Allowance	1,133		1,133	0.21%	45.21	0.09
8	Conservation Costs	2,280		2,280	0.41%	45.21	0.19
9	Miscellaneous	1,954		1,954	0.35%	45.21	0.16
10	Bank Service Charges & PUB Assessment	1,150		1,150	0.21%	(16.18)	(0.03)
11	Uncollectible Bills	1,310	1,310	0	0.00%		-
12	Insurance	1,241		1,241	0.23%	(167.50)	(0.38)
13	Pension & ERP Expense	9,864	6,385	3,479	0.63%	30.40	0.19
14	Other Post Employment Benefits	8,702	5,731	2,971	0.54%	34.80	0.19
15	Severence and Other Employee Costs	73		73	0.01%	45.21	0.01
16	Education and Training	356		356	0.06%	45.21	0.03
17	Trustee & Directors' Fees	467		467	0.08%	36.24	0.03
18	Other Company Fees	3,354		3,354	0.61%	45.21	0.28
19	Stationery & Copying	279		279	0.05%	45.21	0.02
20	Equipment Rental & Maintenance	803		803	0.15%	45.21	0.07
21	Telecommunications	1,586		1,586	0.29%	45.21	0.13
22	Postage	1,553		1,553	0.28%	45.21	0.13
23	Advertising	1,687		1,687	0.31%	45.21	0.14
24	Vegetation Management	1,827		1,827	0.33%	45.21	0.15
25	Computer Equipment & Software	1,336		1,336	0.24%	45.21	0.11
26	Gross operating expenses	86,895		73,469			
27	Less: GEC	(3,135)		(3,135)	-0.57%	36.33	(0.21)
28	Net Operating Expenses	83,760		70,334			
29	Less: Non-Regulated Expenses	(2,993)		(2,993)	-0.54%	41.74	(0.23)
30	**Regulated Operating Expenses**	80,767		67,341			
31							
32	**Purchased Power**	448,896		448,896	81.48%	35.63	29.03
33							
34	**Current Income Tax**						
35	Total Tax	17,852	459	17,393			
36	Plus: Tax Effects of Non-Regulated Expenses	867		867			
37	Regulated Current Income Tax	18,719		18,260	3.31%	90.30	2.99
38							
39	**Municipal Tax Paid**			16,423	2.98%	(115.96)	(3.46)
40							
41	**Cash Operating Expenses in CWC Allowance**			550,920	100.00%		**32.86**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	81,247					
45	Depreciation Expense	55,528					
46	Deferred cost recoveries and amortizations[2]	(4,757)					
47		132,018					
48							
49	**2016 Revenue Requirement**	680,400					

1 Represents items that are not reoccurring cash operating expenses.

2 Includes the amortization of 2016 Hearing costs ($400,000), the deferred recovery of conservation costs (-$5,742,000), the amortization of conservation costs ($1,713,000) and the amortization and deferred recovery of the 2016 revenue shortfall (-$1,128,000).
See Section 3.5 of the Company's evidence.

Newfoundland Power Inc.

2016 Forecast HST Adjustment

		HST ($000's)	Net (Lead) Lag Days	CWC Allowance [1] ($000's)
1	Consumer Billings	(87,577)	(24.28)	(5,810)
2	Other Billings	(496)	225.37	305
3	Purchased Power	58,356	40.42	6,445
4	Operating Expenses	3,164	0.42	4
5				**944**
6				

7 [1] (Lead) Lag Days / 366 * HST

Newfoundland Power Inc.

2016 Forecast Cash Working Capital Allowance

CWC Factor

Revenue Lag Days (Schedule 1)	37.75
Expense Lag Days (Schedule 2)	(32.86)
Net Lag Days	4.89
CWC Factor (4.89 days divided by 366 days)	1.336%

CWC Allowance

Total Cash Operating Expenses (Schedule 2)	550,920
CWC Factor	1.336%
	7,362
HST Adjustment (Schedule 3)	944
CWC Allowance	**8,306**

Newfoundland Power Inc.

2017 Forecast Revenue Lag

Cash Inflows	2017 Forecast[1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
Consumer Billings	691,937	99.50%	36.56	36.38
Other Billings	3,473	0.50%	271.00	1.36
Total	695,410	100.00%		**37.74**

[1] Reconciliation to 2017 Revenue Requirement ($000s) :

Total Billings Above	695,410
Rate Stabilization Adjustments	6,288
Municipal Tax Billings	(16,687)
Billings Recorded as Revenue	685,011
Revenue excluded from CWC Allowance	
Revenue Accrual (non-cash)	242
Equity Portion of AFUDC	490
Total Revenue	685,743
Deduct: Other Revenue	(5,322)
2017 Revenue Requirement from Rates	680,421

Newfoundland Power Inc.

2017 Forecast Expense Lag

		2017 Forcast	Adjustments[1] ($000s)	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
	Operating Expenses						
1	Labour	37,956		37,956	6.86%	37.15	2.55
2	Vehicle Expenses	1,586		1,586	0.29%	45.21	0.13
3	Operating Materials	1,674		1,674	0.30%	45.21	0.14
4	Inter-Company Charges	2,295		2,295	0.41%	45.21	0.19
5	Plants,Subs,System Ops & Buildings	2,314		2,314	0.42%	45.21	0.19
6	Travel	1,274		1,274	0.23%	45.21	0.10
7	Tools and Clothing Allowance	1,155		1,155	0.21%	45.21	0.09
8	Conservation Costs	2,895		2,895	0.52%	45.21	0.24
9	Miscellaneous	1,994		1,994	0.36%	45.21	0.16
10	Bank Service Charges & PUB Assessment	1,173		1,173	0.21%	(16.18)	(0.03)
11	Uncollectible Bills	1,337	1,337	0	0.00%		-
12	Insurance	1,266		1,266	0.23%	(167.50)	(0.38)
13	Pension & ERP Expense	7,622	4,085	3,537	0.64%	30.40	0.19
14	Other Post Employment Benefits	8,228	4,851	3,377	0.61%	34.80	0.21
15	Severence and Other Employee Costs	74		74	0.01%	45.21	0.01
16	Education and Training	363		363	0.07%	45.21	0.03
17	Trustee & Directors' Fees	476		476	0.09%	36.24	0.03
18	Other Company Fees	3,265		3,265	0.59%	45.21	0.27
19	Stationery & Copying	285		285	0.05%	45.21	0.02
20	Equipment Rental & Maintenance	819		819	0.15%	45.21	0.07
21	Telecommunications	1,617		1,617	0.29%	45.21	0.13
22	Postage	1,584		1,584	0.29%	45.21	0.13
23	Advertising	1,717		1,717	0.31%	45.21	0.14
24	Vegetation Management	1,863		1,863	0.34%	45.21	0.15
25	Computer Equipment & Software	1,455		1,455	0.26%	45.21	0.12
26	Gross operating expenses	86,287		76,014			
27	Less: GEC	(2,944)		(2,944)	-0.53%	36.33	(0.19)
28	Net Operating Expenses	83,343		73,070			
29	Less: Non-Regulated Expenses	(3,224)		(3,224)	-0.58%	41.74	(0.24)
30	**Regulated Operating Expenses**	80,119		69,846			
31							
32	**Purchased Power**	448,648		448,648	81.07%	35.63	28.89
33							
34	**Current Income Tax**						
35	Total Tax	18,700	1,406	17,294			
36	Plus: Tax Effects of Non-Regulated Expenses	936		936			
37	Regulated Current Income Tax	19,636		18,230	3.29%	90.30	2.97
38							
39	**Municipal Tax Paid**			16,687	3.02%	(115.96)	(3.50)
40							
41	**Cash Operating Expenses in CWC Allowance**			553,411	100.00%		**32.80**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	84,539					
45	Depreciation Expense	58,555					
46	Deferred cost recoveries and amortizations[2]	(3,734)					
47		139,360					
48							
49	**2017 Revenue Requirement**	687,763					

[1] Represents items that are not reoccurring cash operating expenses.

[2] Includes the amortization of 2016 Hearing costs ($400,000), the deferred recovery of conservation costs (-$7,231,000), the amortization of conservation costs ($2,533,000) and the amortization of the 2016 revenue shortfall ($564,000). See Section 3.5 of the Company's evidence.

Newfoundland Power Inc.

2017 Forecast HST Adjustment

		HST ($000's)	Net (Lead) Lag Days	CWC Allowance [1] ($000's)
1	Consumer Billings	(89,235)	(24.28)	(5,936)
2	Other Billings	(498)	225.37	308
3	Purchased Power	58,324	40.42	6,459
4	Operating Expenses	3,273	0.42	4
5				**835**
6				

7 [1] (Lead) Lag Days / 365 * HST

Newfoundland Power Inc.

2017 Forecast Cash Working Capital Allowance

CWC Factor

1	Revenue Lag Days (Schedule 1)	37.74
2	Expense Lag Days (Schedule 2)	(32.80)
3	Net Lag Days	4.94
4		
5	CWC Factor (4.94 days divided by 365 days)	1.353%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	553,411
13	CWC Factor	1.353%
14		7,487
15	HST Adjustment (Schedule 3)	835
16	**CWC Allowance**	**8,322**

Customer, Energy and Demand Forecast

February 2016

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 INTRODUCTION

The Customer, Energy and Demand forecast (the "forecast"), which is prepared annually, forms the foundation of Newfoundland Power's planning process. The forecast is a key input in developing estimates of capital expenditures required to ensure the electrical system can meet the increasing demands associated with both customer and energy sales growth. The forecast also directly addresses the estimation of future revenue from electrical sales and the Company's single largest expenditure, purchased power.

The forecast was created as of February, 2016.

2.0 FORECAST METHODOLOGY

Introduction

Newfoundland Power provides electrical service to three distinct categories of customers including domestic, general service and street and area lighting. In 2015, domestic accounted for 61% of total energy sales while general service and street and area lighting represented 38% and 1%, respectively.

Domestic

The domestic category includes Rate # 1.1 Domestic Service and Rate # 1.1S Domestic Seasonal – Optional. The domestic category primarily refers to residential dwellings such as single detached homes, single attached homes, apartments and mobile homes. This category also includes non-residential services such as cottages, personal use garages and other metered services that qualify for the domestic rate category. Residential customers use electricity primarily for space and water heating, and the operation of miscellaneous appliances and lighting. In this category, a customer/average use methodology is employed where growth in the number of customers is primarily based on forecast housing starts. Average use is forecast using an end-use/econometric model that includes the market share for electric space heating, personal disposable income and the marginal price of electricity in the current and previous year.

General Service

The general service category primarily refers to commercial, institutional and industrial customers. Unlike the domestic category which represents a relatively homogenous group of customers, the general service category represents a relatively diverse group whose activities include, trade, finance, real estate, public administration, health, education, commercial services, transportation, manufacturing, mining, fishing, forestry and construction. These customers provide goods and services to the local market as well as for export. In 2015, approximately 85% of energy sales in this category were to customers in the service producing sector of the economy while only 15% were in the goods producing sector.

From a forecasting perspective, the general service category is divided into small general service which includes Rate # 2.1 General Service 0 – 100 kW (110 kVA) and large general service which includes Rate # 2.3 General Service 110 kVA (100 kW) – 1000 kVA and Rate # 2.4 General Service 1000 kVA and Over. In the small general service category a customer/average use methodology is employed where the number of customers is primarily based on the number of domestic customers. Average use is forecast using an econometric model that includes the Gross Domestic Product (”GDP”) for the service sector per small general service customer and the average price of electricity in the current year.

Given the relatively small number of customers in the large general service category, an informed opinion methodology is employed and energy sales are forecast on an individual customer basis.

Street and Area Lighting

Street and area lighting energy sales are primarily related to the number of fixtures required to meet the lighting needs of both municipalities and unincorporated communities. At the end of 2015, approximately 62,000 high pressure sodium fixtures were installed. Given the nature of this category, an end use forecasting methodology is employed. The street and area lighting sales forecast is determined by multiplying the forecast quantity of fixtures by the amount of electricity consumed for each fixture type and wattage.

Produced and Purchased

Total energy sales are calculated by adding domestic, general service, and street and area lighting sales. Company use, system losses and wheeled energy are then added to total energy sales to obtain total produced, purchased and wheeled. Company use includes all electricity consumed in facilities owned by Newfoundland Power and used in the delivery of service to customers. System losses refer to energy that is lost during the transmission and distribution of energy between the source of supply and delivery to customers. Wheeled information is provided by Newfoundland and Labrador Hydro.[1]

Purchased energy is calculated by subtracting normal hydro production (“Normal Production”) from the forecast of total produced and purchased. Each year Normal Production is adjusted to reflect plant availability and any modifications to plants that may impact production.

Peak Demand

Newfoundland Power’s native peak is determined using a load factor based methodology. The load factor used in the calculation is the average of 15 years of normalized annual load factors. Native peak is calculated by applying the average load factor to total produced and purchased power. Purchased power demand is calculated by subtracting load curtailment by Newfoundland Power customers and at company owned facilities, and the generation credit from native peak.

3.0 KEY FORECAST ASSUMPTIONS

The forecasting process relies on a wide range of information related to the economy, energy prices, conservation and demand management activities, and other resource based developments within Newfoundland Power’s service territory.

[1] Wheeled energy represents energy that is supplied to Newfoundland and Labrador Hydro customers through Newfoundland Power’s electrical system.

3.1 Economic Outlook

The economic assumptions used in preparing the customer, energy and demand forecasts are based on the Conference Board of Canada, *Provincial Outlook Winter 2016*, *Economic Forecast*, dated February 4, 2016. A table summarizing the historical and forecast key economic indicators for 2009 to 2017 is provided in Appendix A. < >

Over the past 5 years Newfoundland and Labrador has experienced robust economic growth. This performance has been largely attributed to large resource based projects including:

- expansions to existing offshore oilfields;
- the construction of the gravity based structure for the Hebron offshore oilfield;
- the construction and production from Vale's hydromet facility at Long Harbour;
- the development of a number of other mining projects in Labrador; and
- the construction of the Muskrat Falls Hydroelectric Project and associated transmission links.

High oil and metal prices played a pivotal role in the development of most of these projects and positively impacted the Province's fiscal position and infrastructure spending during this period. This strong performance is reflected in the various key economic indicators such as: Gross Domestic Product, in particular the service sector; household disposable income; unemployment rates; and housing starts.

Over the forecast period the economy of Newfoundland and Labrador is expected to struggle. The decline in oil production from existing oilfields; the winding down of construction of Vale's hydromet facility at Long Harbour and the gravity based structure for the Hebron offshore oilfield, and a significant drop in the price of oil and other metals such as iron ore will all negatively impact economic performance. These developments will also significantly impact the fiscal position of the Province and infrastructure spending.

On the positive side industries involved in the export of goods and services such as seafood and newsprint will benefit from a lower Canadian dollar. The manufacturing sector will also receive a boost from increased nickel processing at Vale's hydromet facility at Long Harbour over the next few years.

Overall, growth in key economic indicators such as service sector Gross Domestic Product, employment levels, household disposable income and housing starts will be significantly lower during the forecast as compared to recent history. Given Newfoundland Power's customer base, energy sales growth is primarily influenced by the domestic economy and these key economic indicators. Therefore, forecast customer and energy sales growth is lower than experienced in recent years.

3.2 Energy Prices Outlook

Changes in energy prices have a direct impact on energy sales growth through the inclusion of price elasticity effects in the various models. Overall, customer response to changes in the price of electricity is relatively inelastic. A 1% change in the price of electricity will result in a change in energy sales of less than 1%. Current analysis indicates that a 1% increase in the price of electricity will result in a 0.20% decrease in energy sales. It also indicates the response will vary depending on the time frame and rate category. In addition, changes in oil prices can impact the market share of electricity in the competitive space heating market.

Electricity price forecasts are developed based on information available internally and provided by Newfoundland and Labrador Hydro. The energy sales forecast under existing rates includes: a 2.0% increase on July 1, 2014 related to the annual review of the Rate Stabilization Account; 5.25% decrease on July 1, 2015 related to the annual review of the Rate Stabilization Account and Newfoundland Hydro Interim Rate increase; and the elimination of the 8% Residential Rebate on July 1, 2015 < >. Newfoundland Power's proposed 2.5% increase in customer rates effective July 1, 2016 has also been included in the energy sales forecast under proposed rates.

Furnace oil prices declined by 25% in 2015 and are forecast to decline a further 4% in 2016. Furnace oil prices are forecast to increase by 11% in 2017 as world oil prices start to rebound.[2]

3.3 Conservation and Demand Management Impacts

The energy sales forecast includes the impact of conservation and demand management. The adjustments to the forecast are consistent with the *Five-Year Conservation Plan: 2016 – 2020.*[3]

3.4 Other Inputs

Information from a number of other sources is also used in preparing the forecast. Each year Newfoundland Power surveys approximately 175 large general service customers representing approximately 450 accounts requesting information with respect to future load requirements. This information along with information gathered from Newfoundland Power's regional operations, the St. John's Board of Trade, various other trade organizations, and the provincial and federal governments is also incorporated into the large general service forecast. In addition, information from Canada Mortgage and Housing with respect to housing starts is combined with information received from the Conference Board of Canada in preparing the domestic customer forecast.

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2 Based on US Energy Information Administration, Short-Term Energy Outlook – January 2016 adjusted to reflect a 70 cent Canadian dollar.

3 A copy of the plan is provided in *Volume 2, Exhibits & Supporting Materials, Reports, Tab1*.

4.0 CUSTOMER AND ENERGY FORECAST

Introduction

Appendix B provides the actual customer and energy sales for 2009 - 2015 along with the forecast under both existing and proposed rates for the 2016 - 2017. < > During the 2009 – 2014 period the robust economic performance of the province's economy resulted in average annual customer and energy sales growth of 1.6% and 2.2%, respectively. In 2015 customer and energy sales increased by only 1.1% and 1.0% respectively due to a weakening economy.

Given the province's struggling economy forecast customer and energy sales growth will be much lower than experienced in recent years. The total number of customers is forecast to increase by < > 0.9% in 2016 and 0.8% in 2017. Energy sales under existing rates are forecast to increase by < > 0.7% in 2016 and 0.4% in 2017. Energy sales under proposed rates, which include the elasticity effects of the proposed 2.5% increase, are forecast to increase by < > 0.6% in 2016 and 0.1% in 2017.

Domestic

Growth in the number of Domestic customers is largely a result of housing starts. The Conference Board of Canada forecasts housing starts of < > 1,678 in 2016 and 1,654 in 2017 while Canada Mortgage and Housing Corporation is projecting 1,600 units in 2016 and 1,650 in 2017[4]. Using an average of these forecasts, the number of domestic customers is forecast to grow by < > 0.9% in 2016 and < > 2017.

Domestic electricity consumption is a function of the major end uses in the home, such as space heating, water heating, lighting, and major appliances. In addition, changes in energy prices and income have an impact on electricity consumption. Using proposed rates the average use of energy is forecast to < > decrease by 0.3% in 2016 and 0.4% in 2017.

The combined impact of increased numbers of customers and changes in average use will result in growth in domestic energy sales under proposed rates of < > 0.7% in 2016 and 0.4% in 2017.

General Service

In the small general service rate class 2.1 customer and energy sales growth are dependent on growth in the service-producing sector of the GDP and changes in the price of electricity. In the large general service rate classes 2.3 and 2.4, energy sales are also influenced by changes in the service-producing sector of the GDP. However, in the large general service category, energy sales are mainly determined by changes in the load of larger customers in the goods-producing sector. Information obtained from specific customers is incorporated into forecasts for rate classes 2.3 and 2.4.

Overall, the number of general service customers is forecast to grow by < > 0.5% in 2016 and 2017. Under proposed rates the volume of general service energy sales is forecast to < > increase by 0.5% in 2016 and decrease by 0.5% in 2017. The decrease in energy sales is directly related to the winding down of construction at Vale's hydromet facility in Long Harbour and the completion of the gravity based structure for the Hebron offshore oil project. Together these

[4] < >

projects will negatively impact general service energy sales by 24.2 GWh in 2016 and by an additional 24.1 GWh in 2017.

Street and Area Lighting
In the street and area lighting class, the number of customers is forecast to grow by < > 0.9% in 2016 and < > 2017. The volume of energy sales is forecast to increase by < > 0.9% in 2016 and < > 2017.

Produced and Purchased
Produced and purchased is the sum of total energy sales, company use and system losses. The forecast of company use is based on historical energy usage and information gathered from each of Newfoundland Power's operating areas with respect to the operation of these facilities. System losses are based on historical information and are forecast to be approximately 5.4% of total produced and purchased in < > 2016 and 2017.

5.0 PURCHASED ENERGY AND DEMAND FORECAST

Purchased energy is calculated by subtracting Newfoundland Power's Normal Production from produced and purchased. Newfoundland Power's Normal Production is based on the 2010 Hydro Normal Production Review completed in February 2011. This study recommended a Base Normal Production of 430.5 GWh.

The study also recommended that Normal Production be adjusted annually to reflect the impact on production of any scheduled outages in the year, and that adjustments also be made to reflect the impact on production of physical changes to the plants. Since the completion of the study, modifications have been made to a number of plants and the Base Normal Production has been revised to 438.4 GWh in 2016.

< >

Normal Production is projected to decrease to 427.1 GWh in 2016[5] and increase to 438.0 GWh in 2017.[6] These changes to Normal Production reflect plant availability and modifications to plants that will impact production.

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5 < > A major refurbishment of the Pierre's Brook Hydro plant in 2016 will result in lost production of 11.3 GWh reducing the Normal Production to 427.1 GWh.

6 The Base Normal Production in 2017 is expected to remain unchanged from 2016 at 438.4 GWh. However, planned work at the Tors Cove Hydro Plant will result in lost production of 0.4 GWh reducing the normal to 438.0 GWh in 2017.

Newfoundland Power's forecast of native peak demand is determined by applying the average weather adjusted load factor to the forecast of produced and purchased energy. Newfoundland Power's purchased demand is then derived by subtracting load curtailment by Newfoundland Power customers and company owned facilities and the generation credit approved by the Public Utilities Board.

A copy of the Purchased Energy and Demand Forecast is contained in Appendix C.

6.0 FORECAST ACCURACY

The energy sales forecasts and actual weather adjusted energy sales for the past 10 years are shown in Appendix D. During this period, differences from forecast have ranged from a high of 2.8% to a low of 0.0%. In 5 of the past 10 years, differences from forecast were 1% or less. < >

Newfoundland Power Inc.

Key Economic Indicators[1]
2009 - 2017F

(millions of dollars)

	Actual			**Forecast**					
Indicator	**2009**	**2014**	**Average Growth**	**2015**	**Change From 2014**	**2016**	**Change From 2015**	**2017**	**Change From 2016**
Gross Domestic Product ($ 2007)									
Goods Producing Industries	12,373	12,777	0.6%	11,426	-10.6%	11,265	-1.4%	11,388	1.1%
Service Producing Industries	11,944	13,303	2.2%	13,251	-0.4%	13,432	1.4%	13,586	1.1%
Total of All Industries	24,327	26,006	1.3%	24,605	-5.4%	24,625	0.1%	24,901	1.1%
Consumer Price Index (2002=100)	114.6	128.4	2.3%	129.0	0.4%	131.0	1.6%	133.7	2.1%
Household Disposable Income ($ 2002)	11,088	13,152	3.5%	13,657	3.8%	13,638	-0.1%	13,645	0.0%
Unemployment Rate (%)	15.6%	12.0%	N/A	12.8%	N/A	13.4%	N/A	12.6%	N/A
Housing Starts - Units	3,057	2,119	N/A[2]	1,697	-19.9%	1,678	-1.1%	1,654	-1.4%
Canadian GDP Deflator (2007=100)	101.6	112.9	2.1%	112.4	-0.5%	113.28	0.8%	115.54	2.0%
Canada Mortgage and Housing Corporation[3]									
Housing Starts - Units	3,057	2,119	N/A[2]	1,697	-19.9%	1,600	-5.7%	1,650	3.1%

[1] Conference Board of Canada, Provincial Outlook Winter 2016, Economic Forecast, Dated: February 4, 2016.
[2] The average number of housing starts during the past 5 years was 3,192 units.
[3] Canada Mortgage and Housing Corporation, Housing Market Outlook, Fourth Quarter, 2015.

Newfoundland Power Inc.

Customer and Energy Forecast
2009 - 2017F

			Actual			Actual		Existing				Proposed			
			2009	**2014**	**Average Growth**	**2015**	**Change From 2014**	**2016**	**Change From 2015**	**2017**	**Change From 2016**	**2016**	**Change From 2015**	**2017**	**Change From 2016**
1	Customers														
2															
3	Domestic														
4	Regular	1.1	207,335	222,935	1.5%	225,624	1.2%	227,581	0.9%	229,547	0.9%	227,581	0.9%	229,547	0.9%
5	Seasonal	1.1	-	1,889	-	1,831	-3.1%	1,875	2.4%	1,925	2.7%	1,875	2.4%	1,925	2.7%
6															
7	Total Domestic		207,335	224,824	1.6%	227,455	1.2%	229,456	0.9%	231,472	0.9%	229,456	0.9%	231,472	0.9%
8															
9	General Service														
10	0-100 kW (110 kVA)	2.1	20,806	22,013	1.1%	22,148	0.6%	22,257	0.5%	22,366	0.5%	22,257	0.5%	22,366	0.5%
11	110 kVA (100 kW) - 1000 kVA	2.3	1,088	1,241	2.7%	1,233	-0.6%	1,248	1.2%	1,260	1.0%	1,248	1.2%	1,260	1.0%
12	1000 kVA and Over	2.4	68	70	0.6%	62	-11.4%	61	-1.6%	61	0.0%	61	-1.6%	61	0.0%
13															
14	Total General Service		21,962	23,324	1.2%	23,443	0.5%	23,566	0.5%	23,687	0.5%	23,566	0.5%	23,687	0.5%
15															
16	Street and Area Lighting	4.1	10,010	10,731	1.4%	10,876	1.4%	10,978	0.9%	11,079	0.9%	10,978	0.9%	11,079	0.9%
17															
18	Total Customers		239,307	258,879	1.6%	261,774	1.1%	264,000	0.9%	266,238	0.8%	264,000	0.9%	266,238	0.8%
19															
20	Energy Sales (GWh)														
21															
22	Domestic														
23	Regular	1.1	3,203.3	3,595.3	2.3%	3,636.8	1.2%	3,667.6	0.8%	3,698.3	0.8%	3,660.8	0.7%	3,676.0	0.4%
24	Seasonal	1.1	-	17.8	-	17.4	-2.2%	17.3	-0.6%	17.8	2.9%	17.3	-0.6%	17.8	2.9%
25															
26	Total Domestic		3,203.3	3,613.1	2.4%	3,654.2	1.1%	3,684.9	0.8%	3,716.1	0.8%	3,678.1	0.7%	3,693.8	0.4%
27															
28	General Service														
29	0-100 kW (110 kVA)	2.1	730.7	782.8	1.4%	792.4	1.2%	805.9	1.7%	812.4	0.8%	805.2	1.6%	810.2	0.6%
30	110 kVA (100 kW) - 1000 kVA	2.3	890.5	965.1	1.6%	998.3	3.4%	1,019.3	2.1%	1,027.9	0.8%	1,019.3	2.1%	1,027.9	0.8%
31	1000 kVA and Over	2.4	438.0	505.6	2.9%	479.5	-5.2%	457.1	-4.7%	433.1	-5.3%	457.1	-4.7%	433.1	-5.3%
32															
33	Total General Service		2,059.2	2,253.5	1.8%	2,270.2	0.7%	2,282.3	0.5%	2,273.4	-0.4%	2,281.6	0.5%	2,271.2	-0.5%
34															
35	Street and Area Lighting	4.1	36.5	31.9	-2.7%	32.2	0.9%	32.5	0.9%	32.8	0.9%	32.5	0.9%	32.8	0.9%
36															
37	Total Energy Sales		5,299.0	5,898.5	2.2%	5,956.6	1.0%	5,999.7	0.7%	6,022.3	0.4%	5,992.2	0.6%	5,997.8	0.1%
38															
39	Company Use		11.6	12.3	1.2%	12.0	-2.4%	12.0	0.0%	12.0	0.0%	12.0	0.0%	12.0	0.0%
40															
41	Losses		303.2	336.2	2.1%	340.8	1.4%	343.1	0.7%	344.4	0.4%	342.7	0.6%	343.0	0.1%
42															
43	Produced & Purchased		5,613.8	6,247.0	2.2%	6,309.4	1.0%	6,354.8	0.7%	6,378.7	0.4%	6,346.9	0.6%	6,352.8	0.1%
44															
45	Wheeled		77.9	103.7	5.9%	105.5	1.7%	104.7	-0.8%	102.4	-2.2%	104.7	-0.8%	102.4	-2.2%
46															
47	Total System Energy		5,691.7	6,350.7	2.2%	6,414.9	1.0%	6,459.5	0.7%	6,481.1	0.3%	6,451.6	0.6%	6,455.2	0.1%

Newfoundland Power Inc.

Purchased Energy and Demand Forecast
2016 - 2017F

	Produced Purchased & Wheeled	Total Wheeled Energy	Total Produced & Purchased (NP Native Peak)			Total Curtailed Demand	NP Produced		Total Purchased	
				(1)	(2)	(3)	(4)	(5)		(6)
Year	GWH	GWH	GWH	MW	Load Factor	MW	GWH	Credit MW	GWH	MW
Existing										
2016	6,459.5	104.7	6,354.8	1,409.69	51.32%	11.0	427.1	117.93	5,927.7	1,280.76
2017	6,481.1	102.4	6,378.7	1,418.87	51.32%	11.0	438.0	117.93	5,940.7	1,289.94
Proposed										
2016	6,451.6	104.7	6,346.9	1,407.94	51.32%	11.0	427.1	117.93	5,919.8	1,279.01
2017	6,455.2	102.4	6,352.7	1,413.10	51.32%	11.0	438.0	117.93	5,914.8	1,284.17

Notes:

1. Native peak is the maximim demand forecast to be served by Newfoundland Power. The 2016 native peak reflects the forecast for the winter period of December 2016 to March 2017.
2. Load Factor is based on an average of 15 year historical (normalized) load factors.
3. Based on historical performance of participants plus curtailment of company owned facilities.
4. Normal production for the forecast period is 438.4 GWh adjusted for plant availability and efficiency improvements.
5. Assumes a generation credit of 117.93 MW.
6. The purchased demand for 2016 reflects the purchased demand from Newfoundland and Labrador Hydro for the winter period of December 2016 to to March 2017 and represents Newfoundland Power's forecast billing demand for 2017.

Newfoundland Power Inc.

Comparison of Forecast Energy Sales
To Weather Adjusted Actual Sales[1]

	Forecast Sales[2] (GWh)	Weather Adjusted Actual Sales (GWh)	Difference (GWh)	Difference (%)
2006	5,136.9	4,995.1	-141.8	-2.8
2007	5,023.1	5,092.8	69.7	1.4
2008	5,215.1	5,208.2	-6.9	-0.1
2009	5,244.5	5,299.0	54.5	1.0
2010	5,349.9	5,419.0	69.1	1.3
2011	5,480.0	5,552.8	72.8	1.3
2012	5,658.1	5,680.6	22.5	0.4
2013	5,763.6	5,763.3	-0.3	0.0
2014	5,835.6	5,898.5	62.9	1.1
2015	5,997.2	5,956.6	-40.6	-0.7

Notes:

[1] Sales for 2005 is reported on a billed basis while amounts for 2006 - 2015 are reported on a calendar basis.

[2] The forecast sales figures are from the annual forecasts prepared in the previous year and were part of the Capital Budget presentations made to the Board in those years. The 2008, 2010, 2013 and 2014 forecasts were the basis for the revenue requirement determinations presented as part of the Company's General Rate Applications filed in 2007, 2009 and 2012, respectively.

Conference Board of Canada
Provincial Outlook Winter 2016
Executive Summary
Dated: February 4, 2016

The Conference Board of Canada
Le Conference Board du Canada

PROVINCIAL OUTLOOK EXECUTIVE SUMMARY WINTER 2016

Ontario Is Back Among the Growth Leaders.

At a Glance

- Only four provinces are expected to see their economy grow by more than 2 per cent this year—British Columbia, Ontario, Manitoba, and Nova Scotia.
- The slump in mineral and oil prices will continue to weigh on economic prospects of resource-dependent provinces.
- Alberta is facing another recession this year as cuts in energy investment and job losses hit the economy hard.
- Saskatchewan, battered by falling oil prices that sent the province's economy into recession last year, is facing modest economic growth this year.
- Quebec's economy is unlikely to expand by more than 2 per cent, as the aging of the population constrains labour force growth.

NATIONAL OVERVIEW

After a modest recovery through the summer months, the economy reversed course. Output fell 0.5 per cent in September and was unchanged in October, leaving it 0.2 per cent below where it had been one year earlier. We now estimate that the economy grew by just 1.2 per cent in 2015—the weakest since 2009. The poor finish to the year, together with a further deterioration in oil prices, has caused us to downgrade our economic outlook for 2016. Although much of the recent weakness has been contained to the energy sector, it is beginning to spread to other areas of the economy. The consumer—the main driver of the economy over the last several years—is overstretched, and consumer spending is beginning to show signs of weakening. Meanwhile, the acceleration in exports that was expected for 2016 has so far shown no sign of materializing despite a pickup in the U.S. economy and a large depreciation in the Canadian dollar. The manufacturing sector—another area that should have seen a substantial boost from the decline in the Canadian dollar—saw its output decline through the first 10 months of 2015. Overall, we expect economic growth of just 1.7 per cent in 2016. Stronger growth will have to wait until 2017, when a recovery in the non-energy sector finally takes hold.

While the global economy should do slightly better this year, growth will remain sluggish. On the positive side, Europe's economic recovery continues to pick up steam, Japan should do substantially better this year than last, and the U.S. economy is expected to manage solid growth. However, China's economy is softening, and that was a key factor behind the sluggish demand for raw materials and weak commodity prices last year. The collapse in commodity prices, together with large capital outflows tied to rising U.S. interest rates, will hamper growth in developing economies this year. Latin America will experience no growth this year, while Russia has already tumbled back into recession.

After trading in a range of between US$40 and $60 per barrel for most of 2015, the North American crude oil price benchmark West Texas Intermediate took a turn for the worse. OPEC's decision at its December meeting to boost its production target, along with rising inventory levels, quickly pushed prices to below $40. And in January, prices defied expectations by sinking below $30. Although non-OPEC production is expected to ease this year, a number of factors, including higher oil exports from Iran, imply that world oil supply will continue to outpace demand for the next two years. World oil prices are expected to increase from their January level of $29, mainly because of cuts in U.S. production expected this year. However, with inventories continuing to rise, world oil prices are not forecast to exceed $40 this year.

Given the persistently low oil prices, oil firms are expected to cut their budgets by another 16 per cent in 2016 after a 24 per cent reduction last year. However, falling business investment will not be contained to the energy sector. Non-energy mining investment is dealing with raw material prices that have been falling since 2013. Building construction is expected to decline this year due to sluggish demand, modest employment growth, and rising vacancy rates. At the same time, machinery and equipment spending has been hampered by weak business confidence, sluggish global growth, and a disappointing domestic economy.

One area that is providing a boost to the outlook is the government sector. Combining the promises contained in its election platform, the federal government is expected to pump an additional $10 billion into the economy in fiscal year 2016–17 and again in 2017–18 This year, that will add about 0.3 percentage points to overall economic growth. In addition, while we no longer expect a substantial pickup in exports this year, the trade sector will still make a considerable contribution to economic growth over the near term, offsetting some of the woes in the domestic economy.

Given our projection of only modest economic growth this year, we expect the economy to add just 150,000 jobs in 2016. It will be the third consecutive year of disappointing job gains. However, the unemployment rate, which stood at 7.1 per cent in December but rose to 7.2 per cent in January, will likely remain stable through most of 2016, as labour force growth remains weak due to the increase in retirements among Canada's baby-boom generation. As employment growth finally picks up in 2017, the unemployment rate will begin to fall and is expected to end the year at 6.5 per cent.

Despite the sluggish economic outlook for 2016, we think the Bank of Canada will stand pat and there will be no further interest rate cuts. Rates will remain at their current levels until at least early 2017, when the economy approaches full potential. The loonie is expected to stabilize, averaging US$0.696 over the first half of this year. As oil prices begin to pick up in the second half of 2016 and expectations of an interest rate hike in Canada begin to be priced into the market, the Canadian dollar will see some modest appreciation, reaching US$0.727 by the end of the year.

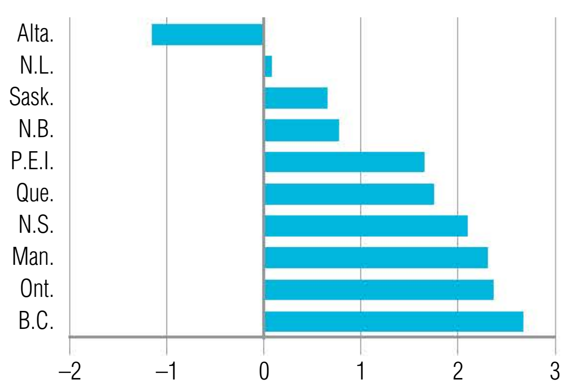
PROVINCIAL OVERVIEW

The slump in mineral and oil prices will continue to weigh on economic prospects of resource-dependant provinces. Alberta is facing another recession this year (see Chart 1) as cuts in energy investment and job losses hit the economy hard. Until imbalances in global oil markets improve, prospects for a recovery in Alberta's economy are bleak. Resource-dependent Saskatchewan, battered by an oil-driven recession last year, is facing modest economic growth this year. A more favourable outlook for agriculture suggests that the sector will help the provincial economy return to growth. Only four provinces are expected to see their economy grow by more than 2 per cent in 2016—British Columbia, Ontario, Manitoba, and Nova Scotia.

While the pickup in exports has been slow to materialize in Ontario despite the 30 per cent depreciation in the Canadian dollar and a strengthening U.S. economic recovery, Ontario's economy has shown some vigour in the last two years, thanks to strong consumer demand. The forecast is positive for Ontario over the next two years. (See Chart 2.) The Quebec economy has not fared well over the past few years, as it has struggled to pick up momentum amid declining business investment. Going forward, stronger U.S. consumer demand will help revive manufacturing activity, as long as business confidence improves and spurs Quebec-based companies to expand operations. Even so, Quebec's economy is unlikely to expand by more than 2 per cent, as the aging of its population constrains the ability of the province to grow its labour force any faster.

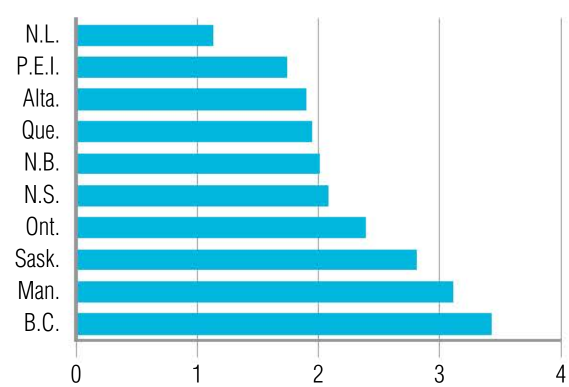
Following up on its solid performance of the last two years, B.C.'s economy will outpace that of any other province both this year and next, thanks to a robust domestic economy. Not far behind is Manitoba, which is set to enjoy strong economic growth as public infrastructure spending and power generation and transmission projects bolster the economy. The East Coast provinces have struggled the last few years, as the region faced large fiscal deficits and an aging population. These structural factors will continue to weigh on the economies of Atlantic Canada, but there are a few rays of sunshine. With a number of major projects under development, construction will continue to be a pillar of strength in Nova Scotia. At the same time, manufacturing will get a lift from shipbuilding. The outlook for New Brunswick remains tame, as no

Chart 1
Real GDP by Province, 2016
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Real GDP by Province, 2017
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

major investments are planned in the near term and construction is set to advance at only a modest pace. However, stronger U.S. housing and consumer demand are fuelling growth in the forestry and manufacturing sectors. Economic prospects for Prince Edward Island are moderate, as the province continues to work on balancing its books. Finally, the economy is not expected to grow in Newfoundland and Labrador this year, as declines in mining and construction hurt overall growth.

PROVINCIAL ASSUMPTIONS

The outlook for Newfoundland and Labrador is grim. The province is facing a massive shortfall of close to $2 billion in its budget for fiscal 2015–16. The province's revenues rely heavily on the oil sector, and an even larger deficit is expected in 2016–17 as oil prices and other commodity prices continue to languish. The government is considering austerity measures to tackle the shortfall, but that won't help the economy at a time when key industries are struggling. Oil production is expected to decline again in 2016, and that trend will persist until the Hebron project starts producing in late 2017. The domestic economy is also weakening. But manufacturing will continue to benefit from nickel being processed in the province. Overall, after contracting by 5.4 per cent in 2015, the Newfoundland and Labrador economy is expected to post almost no growth this year and to grow by just 1.1 per cent in 2017.

Prince Edward Island should see steady economic growth of 1.7 per cent in both 2016 and 2017. The Island will benefit from strong housing demand and a solid increase in manufacturing prompted by the competitive Canadian dollar and robust U.S. household consumption. Real GDP would be even more impressive this year were it not for government spending restraint holding back growth as the provincial government attempts to come through on its promise of balancing the books by 2016–17.

The economic outlook for Nova Scotia is for better times ahead. Economic growth was weighed down in 2015 by a big drop in natural gas production. But construction and manufacturing performed well last year and will help to fuel the province's economy this year and next. The strength in U.S. consumer demand and the lower Canadian dollar will help boost tire production, seafood product sales, and demand for frozen food. All in all, real GDP is expected to increase by 2.1 per cent in 2016 and again in 2017.

Despite an improved performance by New Brunswick's economy last year, the prospects for growth beyond 1 per cent are dim for this year. There are no major investment projects planned in 2016 and that will keep growth in the construction sector modest. And the unexpected shutdown of the Picadilly potash mine in January has dampened the outlook for economic growth. The province will continue to struggle with poor job creation over the near term. On a positive note, forestry and manufacturing will benefit from the strength in U.S. consumer demand and the lower Canadian dollar. Despite the setbacks, total real GDP is expected to inch up 0.8 per cent in 2016. The economic outlook would improve considerably if the proposed Energy East pipeline were to receive the green light to proceed.

As it works to bring its finances back into the black, the Quebec government continues to struggle with a weak economy that has so far failed to gather momentum. Job creation was healthy in 2015, as was consumer demand. What held economic growth to only 1 per cent in 2015 was the lack of business investment, in particular in new structures and in machinery and equipment. Also, exports grew only modestly despite the improved conditions for manufacturers. Looking ahead, economic growth is expected to improve as federal government stimulus and stronger exports help lift economic growth to 1.7 per cent this year and 1.9 per cent in 2019. A much-needed turnaround in business investment will be key to the improving trade performance.

Ontario's economy grew at an average pace of close to 2.5 per cent over the last two years, and more of the same is in store for Canada's manufacturing heartland. Consumer spending and a robust housing sector led the way. As well, business investment held up better than expected. All that was missing was a better trade performance. This year and next, more modest growth is expected for household consumption and housing demand. But the depreciation of the Canadian dollar and stronger economic growth south of the border should combine to finally give a strong boost to exports. At the same time, infrastructure spending will continue to grow, further helping to offset the slowdown in growth in consumer spending. Real GDP in Ontario is expected to grow by 2.4 per cent in 2016 and again in 2017.

Manitoba will be one of the top-performing provinces in the country this year and next. Leading the growth will be agriculture, construction, manufacturing, and the service sector in general. Real GDP growth is forecast to accelerate from 1.5 per cent in 2015 to 2.3 per cent this year, before breaking the 3 per cent mark in 2017 when investment in the Keeyask Generating Station project peaks.

Unfortunately, the economic outlook for Saskatchewan is less than rosy. Hit hard by the oil-driven downturn, Saskatchewan's economy contracted by 2.8 per cent in 2015. In addition, troubles in the agriculture sector also weighed on the economy. Conditions are difficult for Saskatchewan's resource sector. Potash prices are down from one year ago, and some producers are curtailing production. Uranium production, on the other hand, has grown strongly at Cigar Lake mine, and that is expected to continue this year and next. With the world remaining awash in oil, no recovery is expected in the energy sector in 2016. But agriculture could see strong growth if the weather cooperates and allows a more normal harvest. All in all, Saskatchewan's economy is expected to grow by 0.7 per cent in 2016 and by a stronger 2.8 per cent in 2017.

Alberta's recession will continue this year as oil prices feel the pressure of bloating global oil inventories and rising global oil supply. It will take until at least 2017 before the West Texas Intermediate oil price rises back above US$40 per barrel, and even that level is well below the breakeven point for many producers in the province. The number of rigs drilling in January was extremely low, and additional cuts to capital budgets are planned by both conventional and non-conventional oil producers. The outlook is grim for the energy sector, and that is having a knock-on effect on the whole Alberta economy. Consumer confidence has plummeted, and that is dragging down purchases of big-ticket items, including homes. While government stimulus will help as infrastructure spending accelerates, it won't be enough to make up for the steep dive in the energy sector. As a result, Alberta's economy is expected to contract by 1.1 per cent in 2016. More stable conditions in key sectors next year are expected to help lift real GDP by 1.9 per cent. But there remains considerable uncertainty about how long the imbalances in oil market will persist and whether oil prices could remain depressed for an extended period.

British Columbia's economy is on a roll. It is expected to perform better than any other provincial economy in 2016 and again in 2017. We estimate that B.C. posted the strongest economic growth in 2015. And solid demand for new homes will keep housing starts elevated at 32,700 units this year and next. The resale market is showing no signs of slowing down, and that will help fuel the finance, insurance, and real estate industry. Job creation will continue to be strong, fueling household consumption. Despite the downturn in the resource sector, total real GDP is expected to grow 2.7 per cent in 2016 and 3.4 per cent in 2017. The Conference Board forecast includes Petronas' $36-billion Pacific NorthWest liquefied natural gas (LNG) terminal. However, the gap between LNG prices in North America and Asia has been closing rapidly, and there is still some uncertainly about if and when construction will begin. The project adds approximately one percentage point to our real GDP forecast for 2017.

U.S. OUTLOOK

The U.S. Federal Reserve increased interest rates by 25 basis points in December—the first hike since 2006. Rates had been stuck at rock-bottom levels for years due to the sluggishness of the recovery from the 2008–09 recession. But monetary authorities said they are now confident that the economy is in good enough shape to handle a modest increase in interest rates, and they emphasized that future rate increases will also be modest and data-dependent. This implies that if, for instance, economic conditions in emerging markets begin to deteriorate at a faster-than-expected pace, future interest rate increases could be put on hold. In fact, the next Fed rate increase, which had been anticipated for the early spring, could be delayed given the current volatility in global equity markets linked to weaker growth in China and tumbling oil prices. We expect real GDP to expand by 2.8 per cent this year after a 2.5 per cent gain in 2015. But there are downside risks to the forecast, as the U.S. economy underperformed in the final quarter of 2015 due to the strength in the U.S. dollar and the hardships in the energy sector.

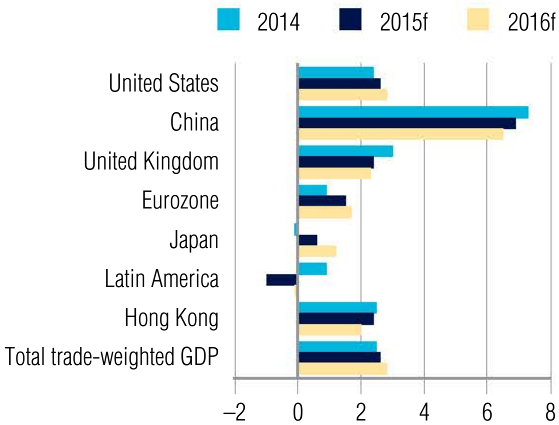
One of the main reasons behind the Fed's decision to increase interest rates was that the economy is on track to reach full employment, likely in the summer of 2016. It has been close to a decade since the economy operated at full employment. Full employment is consistent with an unemployment rate of 5 per cent and an underemployment rate of 9 per cent. The first criterion, a 5 per cent unemployment rate, was reached in the fourth quarter of last year. The underemployment rate currently sits at 9.8 per cent but is on track to hit the 9 per cent mark in the summer. This measurement tool includes the unemployed but adds part-time workers who wish to work longer hours and workers who are discouraged and have left the workforce even though they would prefer to have a job.

The tightening in labour markets has finally started to put upward pressure on wages. Since the end of the 2008–09 recession, wage growth has increased at a sluggish annual pace of around 2 per cent, well below the historical average, which is in the 3–4 per cent range. Many firms have been reluctant to increase wages because of the weak economic growth since the recession ended in the third quarter of 2009. However, in the second half of 2015, wages started to increase above the 2 per cent pace as firms began to offer higher wages in order to attract new workers in a rapidly tightening labour market. Labour income (which includes all forms of worker compensation, including benefits) increased by 4.6 per cent in 2015 and is expected to expand by a healthy 5.6 per cent this year. As a point of comparison, labour income increased by only 3.9 per cent in 2011.

The anticipated increase in wages will translate into healthy gains in household spending over the near term. We expect real consumer spending to expand by 3.1 per cent this year, down slightly from 3.2 per cent last year. Vehicle sales have been a key factor behind the increase in spending as consumers have responded to tumbling gasoline prices (below $2 per gallon in many states) by purchasing gas-guzzling SUVs and pickup trucks. For three straight months, annualized vehicle sales have been at 18.2 million units. In contrast, at the height of the recession in the early part of 2009, sales were stuck well below 10 million units. In addition to low gasoline prices, the introduction of new models, better access to credit, improving labour markets, and manufacturer discounts have helped boost sales. It is unlikely that the present pace of sales can be maintained, as they are well above what population growth would suggest. However, there is still enough pent-up demand (a result of the severe 2008–09 recession and the sluggish recovery) to keep sales moving along at a healthy clip in 2016.

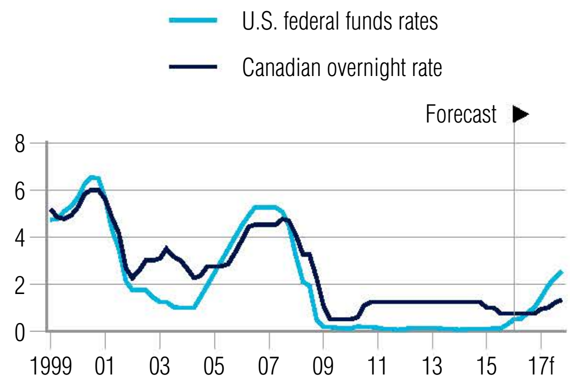
After a sluggish 2015, the world economy should see slightly faster growth in 2016—good news for Canadian exports. Our index of market demand weights expected growth in GDP of Canada's major trading partners by their share of Canada's trade with that country, and it is showing a slight uptick in potential demand for Canadian products in 2016. GDP for Canada's trading partners as a whole is set to increase by 2.8 per cent this year, up from 2.6 per cent last year, as improved conditions in the U.S., Japan, Mexico, and the eurozone will roughly offset weaker growth in China, the United Kingdom, and Latin America. (See Chart 3.)

Chart 3
Growth in Canada's Trading Partners to Accelerate Slightly in 2016
(real GDP, percentage change)



f = forecast
Sources: The Conference Board of Canada; Consensus Economics.

Chart 4
Bank of Canada Expected to Keep Its Key Rate Unchanged Until at Least Early 2017
(per cent)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

MONETARY POLICY

The lack of inflation continues to worry many central bankers across the globe. But in Canada, core inflation continues to run at the midpoint of the Bank of Canada's target range. However, inflation is being driven by transitory factors, most notably the depreciation of the loonie. When making policy decisions, the Bank is expected to look beyond transitory factors and, instead, focus on how the economic outlook influences future inflation. While economic growth at the end of last year was weak, it will pick up this year due to modest growth in exports and the impact of stimulative federal policies. The increase in growth will help sustain inflation at 2 per cent and, as a result, further policy action is not expected from the Bank in the near term. (See Chart 4.)

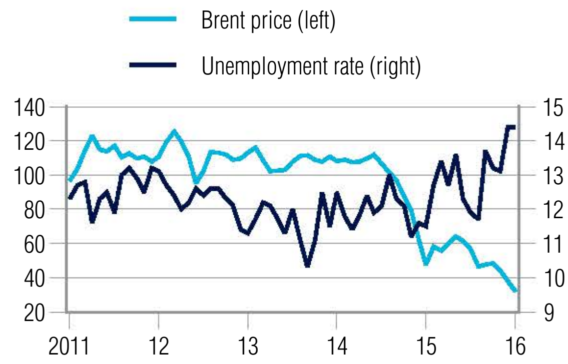
The divergence in monetary policy between the U.S. and Canada has not helped the value of the loonie. But it is the fall in oil prices that has dealt the biggest blow to the value of the Canadian dollar. Commodity prices are expected to remain relatively low this year, with oil prices recovering to just $40 per barrel at the end of the year. Low commodity prices and a continued divergence in monetary policy will keep the loonie soft during the first months of the year, with only a slight recovery anticipated throughout the year due to the uptick in oil prices.

FISCAL OUTLOOK

While the Canadian economy continues to struggle as it adjusts to a world of low oil prices, a new federal government was elected in October—one that promised more spending through targeted tax relief, enhanced benefits, and increased infrastructure investment. Tax changes came into effect on January 1, while infrastructure funding and changes to benefit payments will occur later this year. Combining the promises contained in the election platform, the federal government is expected to pump around $10 billion into the economy in fiscal 2016–17 and 2017–18.

Weaker economic growth, combined with a program of more generous expenditures, will, as expected, drive the federal government back into a deficit. This forecast includes the announced tax changes and assumes that the new Canada Child Benefit starts in July, infrastructure money begins flowing in the second quarter of the year, and spending on enhanced employment insurance and guaranteed income supplement benefits will be in line with the estimates from the Liberal election platform. These expenditures will result in the federal government posting four straight years of deficits, beginning in 2015–2016. The deficit is expected to peak in 2017–18, and by 2019–20 the government should post a slight surplus.

Chart 5
N.L. Jobless Rate Spikes as Crude Oil Prices Tumble
(real GDP, percentage change)



Sources: The Conference Board of Canada; U.S. Energy Information Administration.

NEWFOUNDLAND AND LABRADOR

ECONOMIC GROWTH TO REMAIN WEAK

The rout on commodity markets continues to exert a negative impact on Newfoundland and Labrador's economy. Brent, the benchmark price for North Sea crude oil, has lost more than 70 per cent of its value since the summer of 2014 and has been trading at around US$30 since January. Nickel, copper, and iron ore prices are also weak, as oversupply continues to plague the market. In addition to fundamental market imbalances, Newfoundland and Labrador's economy is being hurt by project-cycle factors. Matured offshore oil fields are producing steadily less oil, and some major construction projects have either been cancelled or have passed their peak investment levels. The weak outlook for commodity prices is having a negative impact on the province's near-term investment and production decisions, and this will have a knock-on effect on the broader economy, resulting in weaker economic growth. After a deep contraction of 5.4 per cent last year, the economy will post almost no growth this year and only a modest recovery of 1.1 per cent next year.

Labour markets will continue to feel the effects of the weakening economy as major projects wrap up. The unemployment rate spiked to 14.4 per cent in January (see Chart 5) and is expected to remain elevated in the first half of this year as more workers return home from the oil patch in Western Canada. The rate will then start to fall gradually, averaging 12.6 per cent in 2017. While the new Liberal government has repealed the previous administration's two-percentage-point HST increase, which had been set to take effect early this year, consumer optimism will remain weak. With slack in the labour market, household consumption will be anemic over the next two years. Government tax collection from resource royalties and households and corporate incomes will be lower in the near term.

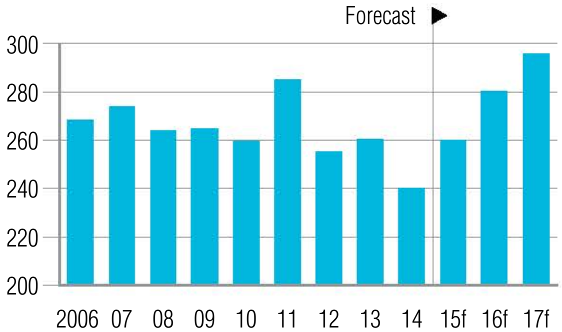
But, despite this sobering outlook, all is not doom and gloom. Manufacturing remains one of the bright spots in the province's economy. The Long Harbour hydromet facility has begun processing nickel, copper, and cobalt ore from the Voisey's Bay mine, which will help offset some of the weakness in offshore oil production and the construction sector.

PRINCE EDWARD ISLAND

SMOOTH SAILING

Prince Edward Island should see steady real GDP growth in 2016 and 2017. Growth is expected to be 1.7 per cent this year and next, led by a strong construction and housing sector (see Chart 6) and a solid

Chart 6
Construction to Be a Major Source of Growth in P.E.I.
(construction output, 2007 $ millions)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

increase in manufacturing (thanks to the low Canadian dollar and robust U.S household consumption). Real GDP would be even more impressive this year if not for government spending holding back growth as the provincial government attempts to come through on its promise to balance its books by 2016–17. The fiscal restraint means weaker growth in non-commercial services, such as education and health and social services, putting a damper on overall economic growth. Government spending should pick up once the balanced budget is achieved, which bodes well for the province over the near term.

Weak government spending is leading the Island's service sector to be a drag on the provincial economy. However, the goods-producing side of the economy more than makes up for this weakness. With housing starts set to rise by 7 per cent this year, the construction sector will be a leading contributor to growth over 2016 and 2017, along with the province's surging export sector. The weak Canadian dollar and strong U.S. household consumption will make the Island's exports more attractive and should help boost the province's manufacturing sector. High lobster prices and demand, as well as rising shipments of frozen french fries to markets south of the border, should also boost the province's exports. P.E.I.'s booming chemical manufacturing industry should continue to grow, thanks to higher demand from pharmaceutical companies in European countries where the populations are aging. The lower dollar should also help bring more tourists to the province, boosting businesses that rely on tourism. Overall, the economic prospects for the province are solid, and steady growth is expected over the near term.

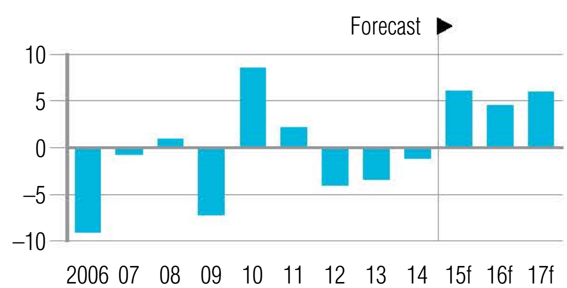
NOVA SCOTIA

NOVA SCOTIA TO LEAD THE ATLANTIC PROVINCES

Nova Scotia's economy is performing well. A sharp contraction in natural gas production pushed real GDP growth down to just 1 per cent in 2015, but a number of key sectors showed strength that should carry over through the near term. Nova Scotia is expected to lead the Atlantic region, with real GDP set to rise 2.1 per cent in 2016 and 2017.

External demand for manufactured goods—such as tires, seafood, and other food products—will continue to fuel manufacturing over the near term. As well, work on the first arctic offshore patrol ship to be delivered under the frigate program is now under way. And by 2017, Irving Shipbuilding intends to have 1,000 people working on construction of the new vessels. After increasing by a strong 6 per cent last year, manufacturing is expected to rise 4.5 per cent in 2016 and 6 per cent in 2017. (See Chart 7.)

Chart 7
Good Times for Nova Scotia's Manufacturers
(manufacturing output, percentage change*)



*based on 2007 $
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Good times are also expected for Nova Scotia's construction industry, which is set to grow by a strong 8.2 per cent in 2016 and 3.4 per cent in 2017. Investment in the Nova Centre—a million-square-foot complex that will include hotel, retail, and office space, as well as a convention centre—will continue until 2017. As well, the undersea Maritime Link and off-shore exploration will fuel investment over the next two years. And residential investment will increase in 2016, as a number of multi-unit projects broke ground in 2015 and will continue to fuel construction activity.

While economic growth will be strong over the near term, employment will rise only modestly in 2016. The overall employment picture will take a hit as Nova Scotians who had gone to work in Alberta's oil patch but who had maintained their residency in Nova Scotia (and therefore are counted as part of Nova Scotia's labour force) are laid off. After advancing by just 0.4 per cent in 2016, employment is expected to increase by 0.8 per cent in 2017. This will keep the unemployment rate elevated at 8.8 per cent in 2016 and 8.5 per cent in 2017.

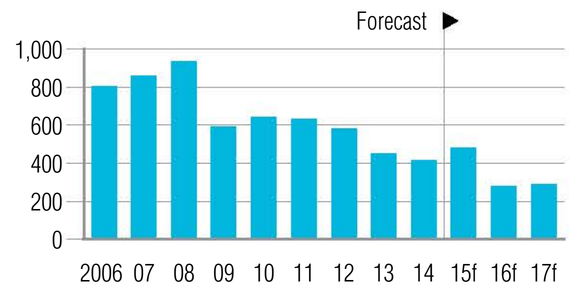
NEW BRUNSWICK

DESPITE SETBACKS, ECONOMY STILL GROWING

Major losses in New Brunswick's mining sector have dampened the outlook for the province's economy over the near term. Although much of the impact of the Picadilly mine closure will be contained to the mining industry, it will cause a decline in goods production in 2016. Overall, New Brunswick's economy will see growth of only 0.8 per cent in 2016, but that will rise to 2 per cent in 2017.

Production at the Picadilly potash mine near Sussex had bred hopes of a strong performance in the mining sector. But the unexpected announcement in January that the mine was shutting down hurts the outlook for the industry over the foreseeable future. Still, Trevali's recently opened Caribou zinc, lead, and silver mine near Bathurst will continue to increase output, generating growth in the mining sector in 2017 but not enough to make up for the large loses this year. (See Chart 8.)

Chart 8
New Brunswick Economy Hurt by the Closure of Picadilly Mine
(mining output, 2007 $ millions)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Strong housing demand south of the border and the extension of the provincial expansion in the allowable cut of softwood lumber on Crown land will continue to spur gains in the forestry sector over the near term. The construction industry will also see growth as ground is broken for the new Moncton downtown entertainment and sports centre and for a new water treatment system in Saint John. If work on the proposed Energy East pipeline were to get under way in the medium term, the construction industry would enjoy solid growth.

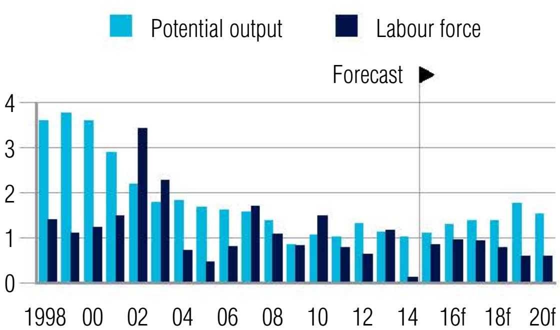
While growth in household disposable income will be respectable, it will not be accompanied by stronger employment, which will remain largely unchanged in 2016 and 2017. Despite disappointing employment numbers, improved household income (fuelled by federal tax cuts) will nevertheless give a boost to retail sales, which are expected to climb at an average annual pace of 4.6 per cent in this year and next. Therefore, unlike the struggling goods-producing sector, the service sector will see moderate but steady gains over the near term.

QUEBEC

ECONOMY TO STRENGTHEN

Despite the uncertainties in the global economy, Quebec will see real GDP grow by 1.7 per cent in 2016, up from a lacklustre 1 per cent last year. Improving exports will help spur stronger economic growth. Real GDP is expected to advance by 1.9 per cent in 2017. At this pace, the Quebec economy will be more or less advancing at its economic potential, and growth is not expected to surpass 2 per cent as labour's contribution to the economy eases as more and more baby boomers retire. (See Chart 9.)

Chart 9
Slow Labour Force Growth a Drag on Quebec's Potential Output
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Robust U.S. household consumption and a Canadian dollar that remains well below parity with its U.S. counterpart will combine to boost Quebec's export-oriented manufacturing industry. Following growth of just 0.7 per cent in 2015, the manufacturing sector is forecast to grow by 2 per cent this year and 2.2 per cent in 2017.

Exports are on track to increase by 2.6 per cent in 2016, up from 1.6 per cent last year. This will help support business investment in Quebec, which will rebound into positive territory and post 0.7 per cent growth this year and 2.8 per cent in 2017. However, if investment fails to pick up as expected, that could hurt export prospects.

With employment poised to increase by 1 per cent in 2016 and 1.2 per cent in 2017, household disposable income will remain healthy. This will support wholesale and retail trade, which will grow by 2.1 per cent this year. Hampered by a climate of fiscal restraint, non-commercial services (which include education and health care, as well as public administration) will see little growth until 2017.

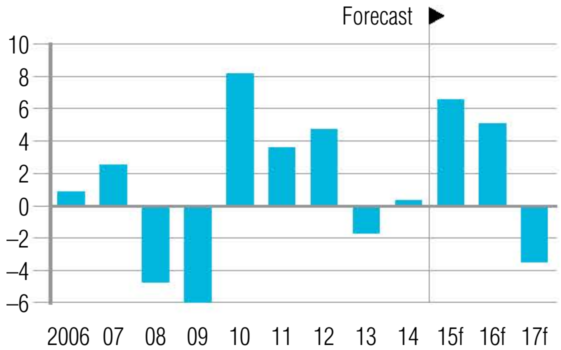
ONTARIO

STRIKING A DELICATE BALANCE

The next five years will see two distinct phases for Ontario's economy. Growth will be solid in both, but the factors driving the growth will change. Temporary factors will spur growth over the next two years. But then, as they begin to taper off, Canada's resource sector will rebound, thereby keeping the economy on track. Ontario is forecast to see economic growth of 2.4 per cent this year, with growth coming in above 2 per cent every year through 2020.

Ontario's international exports will be the key driver of growth in 2016 and 2017. The province's foreign exports (as opposed to interprovincial exports) have been strong of late and, given the low Canadian dollar and robust U.S. demand, are projected to remain so over the next two years. The delay of planned auto plant closures in Windsor and Oshawa will ensure that foreign exports remain strong until 2017, since these plants ship a large portion of their production to the United States. Residential investment will increase in 2016, thanks largely to an investment backlog in 2015 that was due to lower interest rates and homebuyers rushing to avoid the federal government's new mortgage regulations, which took effect earlier this year. (See Chart 10.)

Chart 10
Residential Investment Strong Again This Year in Ontario
(residential investment, percentage change*)



*based on 2007 $
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government spending will weigh on economic growth over the next two years, as the provincial government continues the fiscal austerity plan required to balance its budget on schedule by 2017–18.

Global oil prices are projected to average between US$55 and $65 per barrel after 2018. The resulting increase in the value of the Canadian dollar and economic activity in resource-oriented provinces will boost interprovincial exports, which have struggled of late. Business investment is also expected to pick up at that time, as a more positive outlook for the energy sector and sustained export growth will encourage capacity-building investment. However, the introduction of the proposed Ontario Retirement Pension Plan starting in 2018[1] will act as a drag on household consumption growth.

1 Contributions to the plan were originally scheduled to begin in January 2017. But the Ontario government recently announced that it was pushing back that date one year to give businesses more time to prepare.

MANITOBA

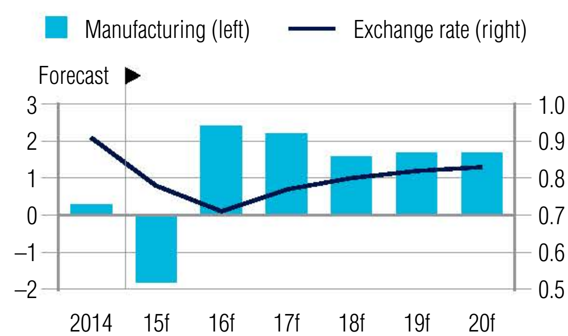
MANITOBA AMONG TOP PROVINCIAL PERFORMERS

Healthy growth across key sectors of Manitoba's economy is creating a strong base for Manitoba to quickly become one of the top-performing provinces. Real GDP growth is forecast to improve to 2.3 per cent this year. Next year, growth is expected to reach 3.1 per cent, the second highest among all provinces.

Fuelling GDP growth over the next two years will be construction as the provincial government continues with its five-year infrastructure plan and Manitoba Hydro projects inject considerable investment dollars into the economy. The construction sector is forecast to grow by 4.4 per cent this year and nearly 10 per cent in 2017, thanks to these projects as well as to housing starts moving back into positive territory.

Growth prospects are brighter for several segments of the manufacturing sector over the next two years, as strong household consumption in the United Sates and a depreciated Canadian dollar are expected to lift exports. (See Chart 11.)

Chart 11
Lower Canadian Dollar a Boon for Manufacturing
(manufacturing output, percentage change*; exchange rate, C$/US$)

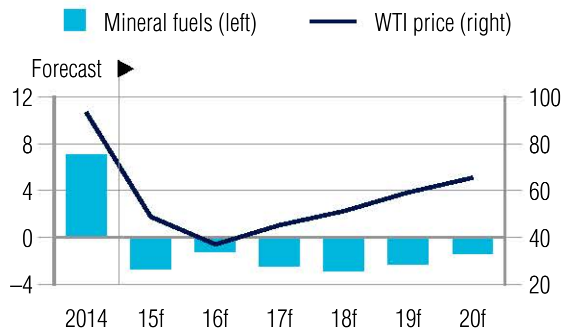


*based on 2007 $
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

The agricultural sector is expected to post 5.7 per cent growth this year if there are no unfavourable weather events to disrupt seeding or harvesting. International trade should sustain strong demand for Manitoba's agricultural products over the next two years. Despite weak commodity prices, metal mines are operating at steady levels.

Solid growth in key industries will support employment and consumption in the province. After posting the strongest job growth in Canada in 2015, Manitoba's job market will see more moderate job creation this year. But job creation will pick up in 2017, with over 11,000 jobs expected to be created. As employment and income grows, households are expected to increase their consumption. That will benefit the retail and wholesale trade sectors, which are expected to grow at an average annual pace of 2.1 per cent over the next two years.

Chart 12
Mineral Fuels Production in Saskatchewan on the Decline
(mineral fuels production, percentage change*; WTI price, US$/barrel)



*based on 2007 $
f = foreceast
Sources: Statistics Canada; The Conference Board of Canada.

SASKATCHEWAN

OIL NO LONGER A SOURCE OF GROWTH FOR SASKATCHEWAN

The downturn in the energy sector will continue to hurt Saskatchewan's economy this year, with the provincial economy expected to squeeze out modest growth of just 0.7 per cent in real GDP. The province's economy is expected to pick up momentum in 2017 with real GDP growing 2.8 per cent thanks to robust construction activity across the province.

The near-term future of the oil industry, one of the key factors behind Saskatchewan's rapid growth post 2008–09 recession, is looking bleak due to the collapse in prices. (See Chart 12.) Facing plunging profitability, stakeholders have responded by slashing their capital investment. As result, mineral fuels production is expected to fall again this year, contracting at a rate of 1.2 per cent. Saskatchewan's mineral fuel production is not expected to grow in the medium term, as conventional oil production is more sensitive to fluctuations in commodity prices. On the other hand, uranium mining will be a bright spot in the province over the next two years, thanks to robust demand from Asia.

Construction is expected to pick up in 2017, with 12.1 per cent growth, thanks to non-residential business investment in mining. Meanwhile, public infrastructure spending across the province is also fuelling the construction sector. The provincial government's four-year plan is set to ramp up in 2016.

The agriculture sector struggled through another difficult year in 2015 as drought hit the province once again. But the sector is expected to recover this year with growth of 11.1 per cent. International trade is expected to get a boost from the strong demand for Saskatchewan's agriculture products.

Little job creation is expected this year, and that is causing households to hold back on their spending. But the province will gain around 4,000 jobs in 2017 as the economy strengthens.

ALBERTA

ANOTHER GRIM YEAR FOR ALBERTA

The rout on crude oil markets will continue to hammer Alberta's economy this year. Global benchmark prices for crude oil have dropped more than 70 per cent from their 2014 summer peak levels, falling to around US$30 per barrel by this past January. The lower pricing environment has devastated the earnings of energy companies, with most reporting double-digit declines in their bottom lines in the final quarter of 2015. Energy companies are reacting to their squeezed cash flows by planning a second round of capital retrenchment. In Alberta, energy investment could fall another $6 billion this year following a $10-billion drop last year. The impacts on the job and housing markets, consumer spending, migration trends, and supplier industries will send Alberta's economy into another tailspin, with real GDP forecast to contract by 1.1 per cent this year on the heels of an estimated 2.9 per cent contraction last year.

This year is going to be another tough one for Albertans. In January, the unemployment rate soared to 7.4 per cent (the highest since March 1996) as employers continued to trim their workforces to align with weaker demand for their products and services. (See Chart 13.) The jobless rate will continue to creep up through the first half of this year before starting to fall gradually as discouraged workers exit the workforce and inter-provincial migration turns negative.

We expect the supply and demand imbalances in crude oil markets to stabilize toward the end of this year.

Chart 13
Alberta's Unemployment Rate Soars
(per cent)

Sources: Statistics Canada.

A modest recovery next year will bring crude prices back up to the mid-US$40s range. This will help the energy sector and its supplier industries to at least start getting back on track.

One thing that will help the economy is public infrastructure spending. The provincial and federal governments are planning massive infrastructure programs to help stimulate the ailing economy. The infrastructure spending, along with sturdy growth in education and health and a modest turnaround in the energy sector, will help lift the overall economy by 1.9 per cent in 2017.

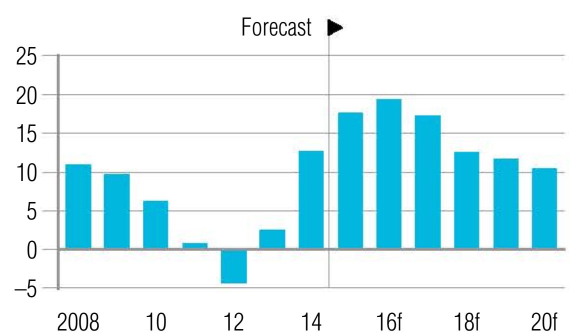
BRITISH COLUMBIA

STELLAR OUTLOOK FOR BRITISH COLUMBIA'S ECONOMY

British Columbia's economy will move into high gear this year, posting real GDP growth of 2.7 per cent. The goods and service industries will grow strongly in 2016, thanks to the broad-based economic strength enjoyed by Canada's most westerly province. This will encourage more Canadians—particularly those in the struggling oil-producing provinces—to move to British Columbia. (See Chart 14.)

After soaring almost 11 per cent in 2015, housing starts will continue to grow this year, albeit at the slower pace

Chart 14
Interprovincial Migrants Choosing British Columbia
(net interprovincial migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

of 3.9 per cent. With the inventory of completed units getting low, prices are still rising and the resale market is red hot. This bodes well for the finance, insurance, and real estate industry, which is poised to post healthy gains over the next few years.

Seaspan Shipyards' multi-billion-dollar contract to build non-combat vessels under the National Shipbuilding Program will continue to bolster the manufacturing sector, as will the low Canadian dollar, which is helping exports. The tourism sector will also benefit from the low loonie, which in turn will benefit the accommodation and food services industry.

Our forecast includes Petronas' $36-billion Pacific NorthWest liquefied natural gas (LNG) terminal. However, the gap between LNG prices in North America and Asia has been closing rapidly, and there is still uncertainly about when and if this major investment will go ahead. The project adds approximately one percentage point to our real GDP forecast in 2017.

The outlook for job creation is bright, with employment forecast to grow by 2.2 per cent in 2016 and 2.4 per cent in 2017, up from 1.3 per cent last year. Accordingly, the unemployment rate will dip below 6 per cent in 2017.

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Table 1—Key Economic Indicators: Provinces
(forecast completed February 4, 2016)

	Gross domestic product at market prices ($ millions)			Gross domestic product at basic prices (2007 $ millions)			Employment (000s)			Unemployment rate (per cent)			Retail sales ($ millions)		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**
Newfoundland and Labrador	29,453	29,211	30,523	24,605	24,625	24,901	236	234	234	12.8	13.4	12.6	8,948	9,272	9,435
	–12.1	*–0.8*	*4.5*	*–5.4*	*0.1*	*1.1*	*–1.0*	*–0.7*	*–0.3*				*0.8*	*3.6*	*1.7*
Prince Edward Island	6,169	6,365	6,580	4,674	4,752	4,834	73	74	74	10.4	9.6	9.3	2,050	2,128	2,179
	2.8	*3.2*	*3.4*	*1.1*	*1.7*	*1.7*	*–1.1*	*0.9*	*0.8*				*2.2*	*3.8*	*2.4*
Nova Scotia	40,009	41,457	43,109	32,661	33,345	34,040	448	450	453	8.6	8.8	8.5	13,923	14,484	14,804
	2.4	*3.6*	*4.0*	*1.0*	*2.1*	*2.1*	*0.1*	*0.4*	*0.8*				*0.1*	*4.0*	*2.2*
New Brunswick	32,887	33,705	34,940	26,236	26,438	26,970	352	351	352	9.7	9.6	9.7	11,931	12,645	13,045
	2.6	*2.5*	*3.7*	*0.9*	*0.8*	*2.0*	*–0.4*	*–0.2*	*0.2*				*3.5*	*6.0*	*3.2*
Quebec	377,342	390,657	404,711	313,420	318,912	325,098	4,097	4,138	4,187	7.6	7.6	7.4	109,176	113,155	117,424
	2.0	*3.5*	*3.6*	*1.2*	*1.8*	*1.9*	*1.0*	*1.0*	*1.2*				*1.0*	*3.6*	*3.8*
Ontario	747,121	778,745	810,532	613,533	628,014	642,988	6,923	7,007	7,102	6.8	6.5	6.2	184,821	193,394	198,975
	3.5	*4.2*	*4.1*	*2.2*	*2.4*	*2.4*	*0.7*	*1.2*	*1.4*				*4.6*	*4.6*	*2.9*
Manitoba	65,993	68,588	72,024	54,377	55,626	57,357	636	643	654	5.6	5.7	5.4	18,282	19,100	19,699
	3.0	*3.9*	*5.0*	*1.5*	*2.3*	*3.1*	*1.5*	*1.0*	*1.8*				*1.4*	*4.5*	*3.1*
Saskatchewan	78,744	78,552	83,136	57,682	58,057	59,685	574	575	579	5.0	5.4	4.9	18,573	18,756	19,127
	–4.9	*–0.2*	*5.8*	*–2.8*	*0.7*	*2.8*	*0.6*	*0.2*	*0.8*				*–3.0*	*1.0*	*2.0*
Alberta	353,251	342,030	358,814	298,011	294,590	300,179	2,302	2,273	2,279	6.0	7.4	7.0	75,804	75,312	76,580
	–6.0	*–3.2*	*4.9*	*–2.9*	*–1.1*	*1.9*	*1.2*	*–1.2*	*0.3*				*–3.5*	*–0.6*	*1.7*
British Columbia	246,454	257,722	269,849	207,802	213,365	220,676	2,308	2,359	2,415	6.1	6.2	5.7	70,670	73,407	76,214
	3.9	*4.6*	*4.7*	*2.3*	*2.7*	*3.4*	*1.3*	*2.2*	*2.4*				*6.6*	*3.9*	*3.8*
Canada	1,988,092	2,038,236	2,126,424	1,645,166	1,671,014	1,710,706	17,949	18,104	18,330	6.9	7.0	6.7	516,042	533,579	549,486
	0.8	*2.5*	*4.3*	*0.7*	*1.6*	*2.4*	*0.9*	*0.9*	*1.3*				*2.2*	*3.4*	*3.0*

For each indicator, the first line is the level and the second line is the percentage change from the previous year.
Shaded area represents forecast data.
Sources: The Conference Board of Canada; Statistics Canada.

Table 2—Key Economic Indicators: Provinces

(forecast completed February 4, 2016)

	Gross domestic product at market prices—per capita ($ per person)			Gross domestic product at market prices—per capita (2007 $ per person)			Employment rate (per 1,000 people)			Household disposable income per capita ($ per person)			Primary household income per capita ($ per person)		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**
Newfoundland and Labrador	55,763	55,224	57,715	49,963	49,995	50,519	533	529	528	33,341	33,775	34,491	36,399	36,503	37,085
	–12.0	*–1.0*	*4.5*	*–4.6*	*0.1*	*1.0*	*–0.8*	*–0.7*	*–0.2*	*4.4*	*1.3*	*2.1*	*3.3*	*0.3*	*1.6*
Prince Edward Island	42,137	43,407	44,732	35,434	36,008	36,485	605	610	614	27,702	28,576	29,475	29,974	30,760	31,462
	2.5	*3.0*	*3.1*	*0.9*	*1.6*	*1.3*	*–1.3*	*0.8*	*0.6*	*4.9*	*3.2*	*3.1*	*3.7*	*2.6*	*2.3*
Nova Scotia	42,405	43,784	45,358	38,322	39,035	39,662	570	570	573	28,733	29,522	30,280	32,656	33,228	33,846
	2.3	*3.3*	*3.6*	*1.1*	*1.9*	*1.6*	*–0.3*	*0.0*	*0.4*	*4.6*	*2.7*	*2.6*	*3.1*	*1.8*	*1.9*
New Brunswick	43,600	44,641	46,147	38,085	38,391	39,018	566	564	564	28,012	28,989	29,919	30,660	31,333	31,984
	2.7	*2.4*	*3.4*	*1.1*	*0.8*	*1.6*	*–0.5*	*–0.3*	*–0.1*	*4.2*	*3.5*	*3.2*	*3.8*	*2.2*	*2.1*
Quebec	45,690	46,905	48,195	40,868	41,199	41,655	599	601	604	26,768	27,481	28,370	32,260	32,982	33,802
	1.3	*2.7*	*2.8*	*0.4*	*0.8*	*1.1*	*0.4*	*0.3*	*0.5*	*2.7*	*2.7*	*3.2*	*2.2*	*2.2*	*2.5*
Ontario	54,209	55,867	57,577	48,189	48,766	49,439	608	609	611	30,429	31,258	32,076	36,751	37,483	38,280
	2.6	*3.1*	*3.1*	*1.6*	*1.2*	*1.4*	*–0.4*	*0.1*	*0.3*	*2.4*	*2.7*	*2.6*	*2.4*	*2.0*	*2.1*
Manitoba	51,067	52,407	54,393	45,807	46,327	47,171	645	643	648	28,657	29,315	30,095	33,094	33,608	34,368
	1.9	*2.6*	*3.8*	*0.4*	*1.1*	*1.8*	*0.4*	*–0.2*	*0.7*	*4.1*	*2.3*	*2.7*	*2.6*	*1.6*	*2.3*
Saskatchewan	69,499	68,317	71,221	54,560	54,182	54,817	666	659	656	33,470	33,685	34,243	38,608	38,435	38,845
	–6.0	*–1.7*	*4.3*	*–3.2*	*–0.7*	*1.2*	*–0.5*	*–1.0*	*–0.5*	*3.6*	*0.6*	*1.7*	*1.9*	*–0.4*	*1.1*
Alberta	84,365	80,352	83,004	74,770	72,797	72,977	686	668	661	40,767	40,191	40,696	49,266	47,956	48,267
	–7.8	*–4.8*	*3.3*	*–4.1*	*–2.6*	*0.2*	*–0.9*	*–2.7*	*–1.1*	*0.3*	*–1.4*	*1.3*	*–1.5*	*–2.7*	*0.6*
British Columbia	52,644	54,344	56,111	48,717	49,439	50,378	595	600	606	32,907	33,957	35,145	38,217	39,265	40,589
	2.8	*3.2*	*3.3*	*1.3*	*1.5*	*1.9*	*0.1*	*0.7*	*1.0*	*4.5*	*3.2*	*3.5*	*3.6*	*2.7*	*3.4*
Canada	55,494	56,269	58,095	49,391	49,672	50,280	613	612	614	31,122	31,768	32,614	37,077	37,572	38,377
	–0.2	*1.4*	*3.2*	*0.3*	*0.6*	*1.2*	*–0.2*	*–0.2*	*0.3*	*2.7*	*2.1*	*2.7*	*2.0*	*1.3*	*2.1*

For each indicator, the first line is the level and the second line is the percentage change from the previous year.
Shaded area represents forecast data.
Sources: The Conference Board of Canada; Statistics Canada.

Insights. Understanding. Impact.

Provincial Outlook Executive Summary: Winter 2016

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Cost of Service Study

October 2015

Table of Contents

1.0 GENERAL

Cost of service studies are conducted on a regular basis to evaluate the reasonableness of cost recovery by class of service and as a step in the traditional process for establishing Newfoundland Power's ("Newfoundland Power" or the "Company") rates.

In the Company's 2003/2004 General Rate Application, the Company presented detailed evidence on its cost of service study methodology. Through a mediation process, the parties at the hearing recommended the approval of the cost of service study methodology. In Order No. P.U. 19 (2003), the Board approved the recommendations as presented in the evidence and the Mediation Report.

In Order No. P.U. 32 (2007), the Board stated that is was satisfied that Newfoundland Power's Cost of Service Study and methodology, along with the Marginal Cost Study, were appropriate to be used in establishing 2008 customer rates.

At Newfoundland Power's 2010 and 2013/14 General Rate Applications, the results of the Company's Cost of Service Studies and their use in establishing customer rates were not an issue and were accepted for use in establishing customer rates.

2.0 2014 *PRO FORMA* COST OF SERVICE STUDY

The Company has completed a 2014 *Pro forma* Cost of Service Study (the "Cost of Service Study"). The detailed results of the Cost of Service Study are shown in Appendix A.

The Cost of Service Study is based on actual costs and revenue incurred in 2014, adjusted to reflect the increase in Purchased Power Costs as a result of Newfoundland and Labrador Hydro's ("Hydro's") Interim Rate increase, including RSP changes, effective July 1, 2015, and associated changes in Newfoundland Power's customer rates.

2.1 *Pro forma* Adjustments

The adjustments made to 2014 costs to reflect Hydro's interim rate increase included the following:

- Increasing the actual 2014 Purchased Power expense by $31,937,000.

- Decreasing revenue from the RSA rate adjustment by 111.29% to reflect an RSA factor change from .930 to - 0.105 ¢/kWh.

- Adjusting the actual revenue from base rates by:

Residential	5.24%
General Service Rate 2.1	5.24%
General Service Rate 2.3	5.24%
General Service Rate 2.4	5.24%
Street and Area Lighting	1.59%

- Adjusting the functional classification of the Purchased Power Costs to reflect the functional classification of the costs allocated to Newfoundland Power from Hydro's proposed 2015 test year cost of service study.

- Adjusting the classification of hydro production to match the system load factor as used in Hydro's proposed 2015 test year cost of service study.

2.2 Cost of Service Study Updates

The Cost of Service Study incorporates results from four specific studies which are updated every five years. These studies were updated based on 2012 actual costs and the results are included in the 2014 *Pro forma* Cost of Service Study. The four studies are:

- Customer Weighting Factor Study.
- Minimum System Analysis.
- Transformer Zero Intercept Analysis.
- General Plant Allocation Study.

Table 1 shows the impact that, in aggregate, the updates to the four studies had on the Company's revenue to cost ratios.

Table 1
Revenue to Cost Ratios
(Percentage)

	With Old Studies	**With New Studies**	**Variance**
Domestic	95.7	95.6	(0.1)
General Service			
(0-100kW)	107.8	108.6	0.8
(110-1000kVA)	112.2	111.9	(0.3)
(1000kVA and Over)	104.9	104.5	(0.4)
Street Lighting	102.4	103.4	1.0
Total	**100.0**	**100.0**	**0.0**

3.0 COST OF SERVICE STUDY RESULTS

Appendix A shows the detailed results of the Cost of Service Study.

The results of the Cost of Service Study have been divided into the following five groups of schedules.

Group 1: Results, pages 2 to 14 of 43.

Group 2: Functional Classification of Rate Base, pages 15 to 22 of 43.

Group 3: Functional Classification of Expenses, pages 23 to 29 of 43.

Group 4: Determination of Class Allocation Factors, pages 30 to 38 of 43.

Group 5: Miscellaneous Schedules, pages 39 to 43 of 43.

3.1 Group 1: Results

Schedule 1.1 shows the major components that make up the total cost of service (excluding Rate Stabilization Costs, Municipal Taxes and the rural deficit funding). The major components include purchased power expenses[1], operating and maintenance expenses, depreciation expenses, expense credits and return and taxes. The schedule shows the breakdown of these cost components into the various functional classification groups used in the study. Expense credits

[1] The purchased power expense excludes the portion of the expense that is attributed to funding Hydro's rural deficit.

include revenue that is either not generated from rates or is recovered through the RSA and is associated with particular functional classification groups.

Schedule 1.2 provides the cost by each functional classification group and the amount allocated to each class of service. The costs do not include Rate Stabilization Costs, Municipal Taxes or the rural deficit funding.

Schedule 1.3 shows the total cost of service by class of service including Rate Stabilization Costs, Municipal Taxes and the rural deficit funding. The schedule also subtracts other revenue from total costs to provide a column representing the total costs recovered from customer final rates.

Schedule 1.4 shows the revenue attributed to each class of service. The schedule shows all the components that make up the total billings to customer plus other revenue. The other revenue amount excludes the revenue treated as expense credits in Schedule 1.1. Other revenue is attributed to each class of service based on the total revenue from base rates by class.

Schedule 1.5 compares the revenue by class to the cost by class and shows the revenue to cost ratios for each class of service. The costs from Schedule 1.3 and the revenues from Schedule 1.4 are used to compute the revenue to cost ratios.

Schedule 1.6 provides rate loaders that when applied to the classified cost components (demand, energy, customer and specifically assigned costs) result in costs that can be compared to final customer rate components. The rate loaders are applied to each of the classified cost components. The RSA loader is added to the classified energy costs.

Schedule 1.7 expresses the cost of service in terms of unit costs. The units costs provided are the $ per kW/kVA for demand costs, ¢/kWh for energy costs, and $/bill for customer related costs. Also provided is a breakdown of demand and customer cost in ¢/kWh and an overall total cost expressed in terms of ¢/kWh.

3.2 Group 2: Functional Classification of Rate Base

Schedule 2.1 shows the original cost of the Company's fixed assets and its breakdown by the various functional classification categories. The total cost is based on the average amount of fixed assets employed during the year.

Schedule 2.2 shows the average accumulated depreciation and its breakdown into functional classification categories.

Schedule 2.3 shows the net contributions in aid of construction ("CIAC"). The net CIAC is the total CIAC received from customers and governments, less the CIAC amortized to date.

Schedule 2.4 shows the average rate base. The average rate base includes the total net utility plant, deductions from rate base and additions to rate base.[2] The net utility plant is the original cost of the fixed assets (Schedule 2.1) less the accumulated depreciation (Schedule 2.2).

3.3 Group 3: Functional Classification of Expenses

Schedule 3.1 shows the Company's expenses, both regulated and non-regulated, by cost of service expense category.

Schedule 3.2 shows the functional classification of the Company's expenses by expense category as follows:

1. Purchased Power Expense.[3]

2. Direct Operating and Maintenance Expenses. These expenses include those internal costs that can be directly placed into functional groups.

3. General System Expense. These expenses include costs related to general operations, communications and the system control center.

4. Administration and General Expenses. These expenses include the costs of administration, human resources, information systems, finance and regulatory costs.

5. CDM Costs. These expenses include CDM general costs, CDM program costs and the costs associated with the Curtailable Service Option.

Schedule 3.3 shows the breakdown of depreciation expense, net of CIAC amortization, into functional classification categories.

3.4 Group 4: Determination of Class Allocation Factors

Schedule 4.1 shows the customer statistics used to develop the allocation factors. The customer statistics include: the number of customers; total energy sales; total billing demand (where applicable); the estimated class load factors based on non-coincident peak ("NCP"); and the estimated class load factors based on coincident peak ("1 CP"). Schedule 4.1 also shows the estimated class demands at time of class peak (NCP) and the estimated class demands at time of Hydro's system peak (1 CP).

---

[2] The deductions from average rate base include the net CIAC (Schedule 2.3), the balance in the weather normalization reserve, other post-employment benefits, customer security deposits, accrued pension obligation, future income taxes, and the demand management incentive account. Since the balance in the weather normalization reserve is owed to customers, the balance is deducted from rate base. The additions to rate base include deferred charges (mostly pension costs), unamortized regulatory cost deferral, customer finance programs, cash working capital allowance, and materials and supplies allowance.

[3] The expense shown in the schedule excludes the portion of the purchased power cost associated with funding Hydro's rural deficit.

Schedule 4.2 shows the loss factors that are used as an input in calculating the energy and demand allocation factors.

Schedule 4.3 shows the development of the allocation factors for customer related costs. The allocation factor for each type of customer cost is based on a weighting factor and the number of customers. An allocation factor of 0.0 per cent occurs in a number of instances, such as the allocation factor used to allocate customer related secondary costs to transmission customers. This reflects the concept that a transmission customer (a customer that takes their electricity supply from the transmission system) is not responsible for any of the cost of the distribution secondary or distribution primary system.

Schedule 4.4 shows the development of the secondary, primary and transmission allocation factors for energy related costs. The allocation factors are based on energy sales and losses. Three separate allocation factors are required to ensure that within the cost of service study, a transmission customer is not allocated any of the cost of the distribution secondary or primary system and that a distribution primary customer is not allocated any of the cost of the distribution secondary system.

Schedule 4.5 shows the development of the NCP demand allocation factors. The allocation factors are based on the estimated class peak and the loss factors shown in Schedule 4.1 and Schedule 4.2 respectively. The table shows three sets of allocation factors that are used when allocating the demand related cost associated with either the secondary, primary or transmission levels.

Schedule 4.6 shows the development of the 1 CP demand allocation factor. The allocation factors are based on the estimated class demand at time of system peak and the loss factors shown in Schedule 4.1 and Schedule 4.2, respectively. The table shows three sets of allocation factors that are used when allocating the demand related cost associated with either the secondary, primary or transmission levels.

3.5 Group 5: Miscellaneous Schedules

Schedule 5.1 shows the functional classification splits used in the Cost of Service Study. The input data was primarily derived from a variety of functionalization and classification studies. The sources of each functionalization and classification split are detailed in the footnotes in Schedule 5.1.

Schedule 5.2 shows the reconciliation of the total expenses used in the Cost of Service Study to the 2014 Annual Report to the Board.

Schedule 5.3 shows the reconciliation of the total revenue used in the Cost of Service Study to the 2011 Annual Report to the Board.

Schedule 5.4 shows the reconciliation of the total return and taxes used in the Cost of Service Study to the 2014 Annual Report to the Board.

Cost of Service Study

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

Table of Contents

Notes:

1 - Within the Schedules rows and columns may not add due to rounding.

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Customer Acc. & Cust. Serv. O	Customer Specific P	Revenue Related Q
1	Purchase Power	375,291	148,346	227,727	(165)	(144)	(281)	0	(121)	0	(70)	0	0	0	0	0	(1)	0
2	Operating and Maintenance	85,403	5,737	5,415	9,007	6,984	10,726	5,282	3,125	831	2,681	1,320	7,832	892	4,145	18,895	64	2,467
3	Depreciation	49,288	3,647	2,794	6,415	4,002	9,879	4,866	3,462	920	2,470	1,217	3,565	1,453	2,220	2,328	49	0
	Expense Credits																	
	Wheeling Revenues																	
4	Transmission	477	0	0	477	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Distribution	219	0	0	0	0	146	72	0	0	0	0	0	0	0	0	0	0
6	Joint Use Revenue	2,448	0	0	0	0	1,312	646	0	0	328	162	0	0	0	0	0	0
7	Revenue from Temp. Service and Reconnects	87	0	0	0	0	0	0	0	0	0	0	87	0	0	0	0	0
8	Customer Service Fees	295	0	0	0	0	0	0	0	0	0	0	0	0	0	295	0	0
9	RSA Transfer - Energy Supply Cost Variance	1,838	0	1,838	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	RSA Transfer - PEVDA and OPEBS	1,724	118	109	198	150	269	132	84	22	67	33	150	22	79	288	1	0
11	RSA Transfer - Seasonal Rate Revenue Deferral	57	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	57
12	RSA Transfer - CDM Revenue Deferral	420	0	420	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Expense Credits	7,565	118	2,367	676	150	1,728	851	84	22	395	195	237	22	79	583	1	57
14	Subtotal Expenses	502,417	157,613	233,570	14,582	10,692	18,597	9,297	6,383	1,729	4,686	2,342	11,159	2,323	6,287	20,639	110	2,410
15	Return and Taxes	92,479	6,918	6,994	11,634	9,990	18,243	9,002	8,091	2,155	4,561	2,250	4,086	2,506	3,012	2,911	94	32
16	Total Cost of Service (Excluding RSA, MTA, Rural Deficit)	594,896	164,531	240,564	26,216	20,682	36,840	18,299	14,474	3,883	9,247	4,593	15,245	4,828	9,298	23,550	203	2,442

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE

Line No.	Category	
1	Purchase Power	Taken from Schedule 3.2, Line 6. (Excludes the Rural Deficit of $59,488,702.)
2	Operating and Maintenance	Taken from Schedule 3.2, Line 39 less Line 6. (Excludes non-regulated expenses of $2,800,957.)
3	Depreciation	Taken from Schedule 3.3, Line 20
	Expense Credits	
	Wheeling Revenues	
4	Transmission	Allocated based on functional classification of Transmission O&M expenses excluding specifically assigned (Schedule 3.2, Line 9).
5	Distribution	Based on the functional classification of Primary Distribution (Schedule 3.2, Line 14, Columns F & G).
6	Joint Use Revenue	Based on the functional classification of Poles, Lines and Fittings (Schedule 3.2, Line 14).
7	Revenue from Temp. Service and Reconnects	Based on functional classification of Services (Schedule 3.2, Line 15).
8	Customer Service Fees	Functional Classification based on 100% Customer Service/ Customer Accounting.
9	RSA Transfer - Energy Supply Cost Variance	Classified 100% to Energy
10	RSA Transfer - PEVDA and OPEBS	Functional Classification based on the Weighted Split for Administration and General. (See Notes to Schedule 3.2)
11	RSA Transfer - Seasonal Rate Revenue Deferral	Assigned 100% as Revenue Related.
12	RSA Transfer - CDM Revenue Deferral	Classified 100% to Energy
13	Total Expense Credits	Sum of lines 4 through 12.
14	Subtotal Expenses	Total of Lines 1, 2, and 3, less Line 13. (See Schedule 5.2 for the reconcillation to Total Company Expenses as Reported.)
15	Return and Taxes	Functional Classification based on Total Average Rate Base, Schedule 2.4, Line 38. (See Schedule 5.4 for the reconcillation to total Company Return and Taxes as Reported.)
16	Total Cost of Service (Excluding RSA, MTA, Rural Subsidy)	Total of Lines 14 and 15.

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE
Total Cost of Service excludes RSA, MTA and Rural Deficit (All numbers are times $1,000)

Line No.	Class of Service	Rate Code	Total	Produced & Purchased Demand A	Produced & Purchased Energy B	Transmission Demand C	Distribution: Substation Demand D	Distribution: Primary Demand E	Distribution: Primary Customer F	Distribution: Transformers Demand G	Distribution: Transformers Customer H	Distribution: Secondary Demand I	Distribution: Secondary Customer J	Distribution: Services Customer K	Distribution: Meters Customer L	Distribution: St. Lighting Customer M	Customer Acc. & Cust. Serv. N	Specifically Assigned O	Revenue Related P
	Allocation Factors Used ==>			Transmission 1CP	Transmission Energy	Transmission 1CP	Primary NCP	Primary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Weighted Customers	Weighted Customers		Weighted Customers		Revenue
	DOMESTIC																		
1	Domestic Regular	1.1	96,909	24,184	34,159	3,853	3,429	6,108	5,411	2,552	1,096	1,630	1,359	4,683	1,112	0	6,957	0	376
2	Domestic All Electric	1.1	298,194	88,786	113,303	14,147	10,210	18,186	10,481	7,599	2,123	4,855	2,632	9,071	2,154	0	13,475	0	1,173
3	Total Domestic	1.1	395,103	112,970	147,462	18,000	13,639	24,294	15,892	10,151	3,218	6,485	3,990	13,754	3,266	0	20,432	0	1,550
	GENERAL SERVICES																		
4	(0-10 kW)	2.1	11,665	2,263	4,024	361	341	608	882	254	214	162	222	764	272	0	1,248	0	50
5	(10-100 kW)	2.1	61,215	17,154	27,925	2,733	2,292	4,082	676	1,706	246	1,090	170	643	834	0	1,390	0	275
6	Total (0-100 kW)	2.1	72,880	19,417	31,948	3,094	2,633	4,690	1,558	1,959	461	1,252	391	1,407	1,106	0	2,638	0	325
	(110-1000 kVA)	2.3																	
7	Primary (110-350 kVA)		1,460	410	768	65	58	104	2	0	0	0	0	0	42	0	4	0	7
8	Secondary (110-350 kVA)		38,819	10,605	19,779	1,690	1,506	2,682	65	1,121	39	716	16	84	201	0	133	0	183
9	Transmission (350-1000 kVA)		155	49	93	8	0	0	0	0	0	0	0	0	5	0	0	0	1
10	Primary (350-1000 kVA)		7,452	2,141	4,015	341	304	541	3	0	0	0	0	0	68	0	6	0	33
11	Secondary (350-1000 kVA)		28,538	7,877	14,691	1,255	1,118	1,992	16	832	10	532	4	0	50	0	33	0	127
12	Total (110-1000 kVA)	2.3	76,425	21,081	39,346	3,359	2,986	5,319	86	1,953	49	1,248	20	84	366	0	177	0	351
	(1000 kVA and Over)	2.4																	
13	Transmission		722	183	378	29	0	0	0	0	0	0	0	0	5	0	0	123	3
14	Primary		23,805	6,601	13,466	1,052	873	1,555	3	0	0	0	0	0	66	0	5	80	102
15	Secondary		12,288	3,284	6,662	523	434	774	2	323	1	207	1	0	19	0	5	0	52
16	Total (1000 kVA and Over)	2.4	36,815	10,069	20,507	1,604	1,308	2,329	5	323	1	207	1	0	91	0	11	203	157
17	**STREET LIGHTING**	4.1	13,673	994	1,301	158	117	208	758	87	153	56	190	0	0	9,298	292	0	59
18	Total		594,896	164,531	240,564	26,216	20,682	36,840	18,299	14,474	3,883	9,247	4,593	15,245	4,828	9,298	23,550	203	2,442

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE

NOTES:

Line No.	Category	
18	Total	Total Cost of Service shown in Schedule 1.1, Line 16.

Col.		
A	Produced and Purchased Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
B	Produced and Purchased Energy	Transmission Energy Allocator taken From Schedule 4.4, Column L.
C	Transmission Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
D	Distribution Substation Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
E	Distribution Primary Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
F	Distribution Primary Customer	Primary Lines Customer Allocator taken from Schedule 4.3, Column G.
G	Distribution Transformer Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
H	Distribution Transformer Customer	Transformer Customer Allocator taken from Schedule 4.3, Column M.
I	Distribution Secondary Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
J	Distribution Secondary Customer	Secondary Lines Customer Allocator taken from Schedule 4.3, Column J.
K	Distribution Services Customer	Service Drop Allocator taken from Schedule 4.3, Column P.
L	Distribution Meters Customer	Meters Allocator taken from Schedule 4.3, Column S.
M	Distribution Street Lighting Customer	All Allocated to Street Lighting Rate Class.
N	Cust. Accounting and Cust. Services	Customer Allocator taken from Schedule 4.3, Column D.
O	Specifically Assigned	Total cost are allocated to class based on the amount of fixed plant dedicated to supplying single customers and the class which those customers belong.
P	Revenue Related	Total cost is allocated based on revenue from class plus RSA and MTA revenue, Column I, from Schedule 1.4.

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

TOTAL ALLOCATION OF THE COST OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Energy A	Demand B	Customer C	Street Lighting D	Specifically Assigned E	Revenue Related Expenses F	Total before RSA, MTA and Rural Deficit G	Allocated Rural Subsidy H	MTA I	RSA J	Total Cost to Serve K	Allocation of Other Revenue L	Total Cost Recovered in Final Rates M
	DOMESTIC														
1	Domestic Regular	1.1	34,159	41,756	20,617	0	0	376	96,909	9,691	2,475	(882)	108,193	416	107,777
2	Domestic All Electric	1.1	113,303	143,783	39,935	0	0	1,173	298,194	29,819	7,712	(2,912)	332,813	1,298	331,515
3	Total Domestic	1.1	147,462	185,540	60,552	0	0	1,550	395,103	39,510	10,187	(3,794)	441,006	1,715	439,292
	GENERAL SERVICE														
4	(0-10 kW)	2.1	4,024	3,989	3,602	0	0	50	11,665	1,166	332	(105)	13,059	56	13,003
5	(10-100 kW)	2.1	27,925	29,056	3,959	0	0	275	61,215	6,121	1,806	(723)	68,418	304	68,114
6	Total (0-100 kW)	2.1	31,948	33,045	7,561	0	0	325	72,880	7,288	2,138	(828)	81,477	360	81,117
	(110-1000 kVA)	2.3													
7	Primary (110-350 kVA)		768	637	48	0	0	7	1,460	146	44	(20)	1,630	7	1,623
8	Secondary (110-350 kVA)		19,779	18,318	540	0	0	183	38,819	3,882	1,200	(511)	43,390	202	43,188
9	Transmission (350-1000 kVA)		93	57	5	0	0	1	155	16	6	(2.4202)	174	1	173
10	Primary (350-1000 kVA)		4,015	3,327	77	0	0	33	7,452	745	220	(107)	8,310	37	8,273
11	Secondary (350-1000 kVA)		14,691	13,607	112	0	0	127	28,538	2,854	838	(388)	31,841	141	31,700
12	Total (110-1000 kVA)	2.3	39,346	35,946	782	0	0	351	76,425	7,642	2,308	(1,029)	85,346	389	84,957
	(1000 kVA and Over)	2.4													
13	Transmission		378	212	5	0	123	3	722	72	19	(10.1127)	804	3	800
14	Primary		13,466	10,082	74	0	80	102	23,805	2,380	672	(358)	26,499	114	26,386
15	Secondary		6,662	5,545	29	0	0	52	12,288	1,229	344	(174)	13,687	58	13,628
16	Total (1000 kVA and Over)	2.4	20,507	15,839	108	0	203	157	36,815	3,681	1,035	(542)	40,990	175	40,815
17	**STREET LIGHTING**	4.1	1,301	1,621	1,394	9,298	0	59	13,673	1,367	385	(33)	15,392	64	15,328
18	Total		240,564	271,990	70,398	9,298	203	2,442	594,896	59,489	16,052	(6,227)	664,211	2,703	661,508

TOTAL ALLOCATION OF THE COST OF SERVICE

NOTES:

Column

A	Energy cost taken from Schedule 1.2, Column B.
B	Demand cost taken from Schedule 1.2, as the sum of Columns A, C, D, E, G and I.
C	Customer cost taken from Schedule 1.2, as the sum of Columns F, H, J, K, L and N.
D	Direct Street Lighting Cost taken from Schedule 1.2, Column M.
E	Specifically assigned cost taken from Schedule 1.2, Column O.
F	Revenue Related Expenses taken from Schedule 1.2, Column P.
G	Sum of Columns A through F.
H	Rural Surcharge allocated to Class based on total cost before Rural Deficit, RSA & MTA, Column G.
I	MTA cost taken as equal to MTA revenue as taken from Schedule 1.4 Column G.
J	RSA cost taken as equal to revenue from RSA factor from Schedule 1.4 Column F.
K	Sum of Columns G through J.
L	Taken from the sum of Schedule 1.4, Column C.
M	Column K less Column L.

REVENUE BY CLASS OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Revenue from Base Rates: Base Rates A	Revenue from Base Rates: Forfeited Discounts B	Allocation of Other Revenue C	Remove Rural Subsidy D	Total Before Rural Subsidy E	RSA Revenue F	MTA Revenue G	Rural Subsidy H	Total Revenue + RSA & MTA I	Total Revenue from Final Rates J
	DOMESTIC											
1	Domestic Regular	1.1	99,850	552	416	(9,691)	91,127	(882)	2,475	9,691	102,411	101,995
2	Domestic All Electric	1.1	311,245	1,751	1,298	(29,819)	284,476	(2,912)	7,712	29,819	319,095	317,797
3	Total Domestic		411,095	2,303	1,715	(39,510)	375,603	(3,794)	10,187	39,510	421,506	419,791
	GENERAL SERVICE											
4	(0-10 kW)	2.1	13,370	80	56	(1,166)	12,340	(105)	332	1,166	13,733	13,678
5	(10-100 kW)	2.1	73,014	330	304	(6,121)	67,526	(723)	1,806	6,121	74,730	74,426
6	Total (0-100 kW)	2.1	86,384	410	360	(7,288)	79,866	(828)	2,138	7,288	88,464	88,104
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		1,778	6	7	(146)	1,645	(20)	44	146	1,815	1,808
8	Secondary (110-350 kVA)		48,589	178	202	(3,882)	45,088	(511)	1,200	3,882	49,658	49,456
9	Transmission (350-1000 kVA)		235	1	1	(16)	221	(2)	6	16	240	239
10	Primary (350-1000 kVA)		8,938	23	37	(745)	8,252	(107)	220	745	9,111	9,073
11	Secondary (350-1000 kVA)		33,950	133	141	(2,854)	31,371	(388)	838	2,854	34,674	34,532
12	Total (110-1000 kVA)	2.3	93,488	341	389	(7,642)	86,577	(1,029)	2,308	7,642	95,498	95,108
	(1000 kVA and Over)	2.4										
13	Transmission		782	1	3	(72)	713	(10)	19	72	795	791
14	Primary		27,317	72	114	(2,380)	25,122	(358)	672	2,380	27,816	27,703
15	Secondary		13,939	48	58	(1,229)	12,816	(174)	344	1,229	14,214	14,156
16	Total (1000 kVA and Over)	2.4	42,037	120	175	(3,681)	38,650	(542)	1,035	3,681	42,825	42,650
17	**STREET LIGHTING**	4.1	15,504	0	64	(1,367)	14,201	(33)	385	1,367	15,920	15,856
18	Total		648,508	3,174	2,703	(59,489)	594,896	(6,227)	16,052	59,489	664,211	661,508

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

REVENUE BY CLASS OF SERVICE

NOTE:
Column

A - From Booked Revenue and Bill Frequency Analysis adjusted for July 2015 rate change
B - From Booked Revenue and Bill Frequency Analysis adjusted for July 2015 rate change
C - Includes Other Revenue as reported in Return 14 of annual Report to Board less Expense Credit from Schedule 5.2 Reconcillation of Expenses. Total Allocated to Customer Class based on the Totals for Column A plus B.
D - The rural deficit cost is removed from revenue by allocating the cost to each customer class based on class cost as shown on Schedule 1.3 Column H.
E - Total of Columns A through D.
F - From actual MTA booked and Bill Frequency Analysis adjusted for July 1, 2015 rate change.
G - From actual RSA booked and Bill Frequency Analysis adjusted for July 1, 2015 rate change.
H - From Column D.
I - Total of Columns E through H.
J - Column I less Column C.

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

REVENUE TO COST RATIO
Including RSA, MTA and Rural Subsidy
(All dollars are times 1,000)

Line No.	Class of Service	Rate	Revenue from Final Rates A	Costs B	Revenue to Cost Ratio C
1	**DOMESTIC**	1.1	419,791	439,292	95.6%
	GENERAL SERVICE				
2	(0-100 kW)	2.1	88,104	81,117	108.6%
3	(110 - 1000 kVA)	2.3	95,108	84,957	111.9%
4	(1000 kVA and Over)	2.4	42,650	40,815	104.5%
5	**STREET LIGHTING**	4.1	15,856	15,328	103.4%
6	Total		661,508	661,508	100.0%

Column
A Revenue from Schedule 1.4, Column J.
B Costs from Schedule 1.3, Column M.
C Column A divided by Column B.

Newfoundland Power
2014 Pro forma Cost of Service Study

CLASSIFIED COST LOADERS BY CLASS

Line No.	Class of Service	Rate Code	Rural Subsidy A	Revenue Related Costs B	Non-Rate Revenue Recovery C	MTA D	Total Costs in Loader E	Total Classified Costs F	% Rate Loader G	RSA H	Sales MWh I	RSA cents/kWh J
	% Loader to be assigned to each Classified Cost Component									RSA Cost Loader (cents/kWh)		
	DOMESTIC											
1	Domestic Regular	1.1	9,691	376	(416)	2,475	12,126	96,533	12.56%	(882)	836,962	(0.105)
2	Domestic All Electric	1.1	29,819	1,173	(1,298)	7,712	37,406	297,021	12.59%	(2,912)	2,776,133	(0.105)
3	Total Domestic	1.1	39,510	1,550	(1,715)	10,187	49,531	393,554	12.59%	(3,794)	3,613,095	(0.105)
	GENERAL SERVICE											
4	(0-10 kW)	2.1	1,166	50	(56)	332	1,493	11,615	12.86%	(105)	98,589	(0.106)
5	(10-100 kW)	2.1	6,121	275	(304)	1,806	7,898	60,940	12.96%	(723)	684,210	(0.106)
6	Total (0-100 kW)	2.1	7,288	325	(360)	2,138	9,391	72,554	12.94%	(828)	782,799	(0.106)
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		146	7	(7)	44	189	1,454	13.01%	(20)	18,992	(0.106)
8	Secondary (110-350 kVA)		3,882	183	(202)	1,200	5,062	38,637	13.10%	(511)	484,612	(0.105)
9	Transmission (350-1000 kVA)		16	1	(1)	6	21	154	13.75%	(2.4202)	2,349	(0.103)
10	Primary (350-1000 kVA)		745	33	(37)	220	962	7,419	12.96%	(107)	99,212	(0.108)
11	Secondary (350-1000 kVA)		2,854	127	(141)	838	3,678	28,410	12.95%	(388)	359,967	(0.108)
12	Total (110-1000 kVA)	2.3	7,642	351	(389)	2,308	9,912	76,074	13.03%	(1,029)	965,132	(0.107)
	(1000 kVA and Over)	2.4										
13	Transmission		72	3	(3)	19	91	719	12.67%	(10.1127)	9,595	(0.105)
14	Primary		2,380	102	(114)	672	3,041	23,703	12.83%	(358)	332,798	(0.108)
15	Secondary		1,229	52	(58)	344	1,567	12,236	12.80%	(174)	163,236	(0.107)
16	Total (1000 kVA and Over)	2.4	3,681	157	(175)	1,035	4,699	36,658	12.82%	(542)	505,628	(0.107)
17	**STREET LIGHTING**	4.1	1,367	59	(64)	385	1,746	13,615	12.83%	(33)	31,886	(0.104)
18	Total		59,489	2,442	(2,703)	16,052	75,280	592,455	12.71%	(6,227)	5,898,540	(0.106)

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

CLASSIFIED COST LOADERS BY CLASS

NOTE:
Column
A - See Schedule 1.3, Column H.
B - See Schedule 1.3, Column F.
C - See Schedule 1.3, Column L. (Negative).
D - See Schedule 1.3, Column I.
E - Total of Columns A through D.
F - See Schedule 1.3, Sum of Columns A through E.
G - Column E divided by Column F.
H - See Schedule 1.3, Column J.
I - See Schedule 4.1, Column D.
J - Column H divided by Column I.

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

Line No.	Class of Service	Rate Code	Billing Statistics From Schedule 4.1: Energy Sales MWh A	Billing Statistics From Schedule 4.1: Average Number of Customers B	Billing Statistics From Schedule 4.1: Total Billing Demands kW - kVA C	Unit Energy Costs cent/kWh D	Unit Demand Costs: By Energy Sales cent/kWh E	Unit Demand Costs: By Billing Demand $/kW - $/kVA F	Unit Customer Costs: By Energy Sales cent/kWh G	Unit Customer Costs: By Number of Customers $/Cust/month H	Specifically Assigned / Street Lighting Cost by Sales cent/kWh I	Total Cost by Sales cent/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	836,962	76,068	0	4.489	5.616	0.00	2.773	25.42	0.000	12.877
2	Domestic All Electric	1.1	2,776,133	147,342	0	4.490	5.832	0.00	1.620	25.43	0.000	11.942
3	Total Domestic	1.1	3,613,095	223,410	0	4.490	5.782	0.00	1.887	25.43	0.000	12.158
	GENERAL SERVICE											
4	(0-10 kW)	2.1	98,589	12,404	0	4.500	4.566	0.00	4.123	27.31	0.000	13.189
5	(10-100 kW)	2.1	684,210	9,502	2,582,616	4.505	4.797	12.71	0.654	39.22	0.000	9.955
6	Total (0-100 kW)	2.1	782,799	21,906	2,582,616	4.504	4.768		1.091	32.49	0.000	10.362
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		18,992	27	50,892	4.467	3.790	14.14	0.287	168.49	0.000	8.544
8	Secondary (110-350 kVA)		484,612	912	1,614,720	4.511	4.275	12.83	0.126	55.76	0.000	8.912
9	Transmission (350-1000 kVA)		2,349	2	12,372	4.383	2.737	5.20	0.251	245.58	0.000	7.371
10	Primary (350-1000 kVA)		99,212	43	262,824	4.463	3.788	14.30	0.088	168.42	0.000	8.339
11	Secondary (350-1000 kVA)		359,967	225	1,067,282	4.502	4.269	14.40	0.035	46.99	0.000	8.806
12	Total (110-1000 kVA)	2.3	965,132	1,209	3,008,090	4.501	4.210	13.51	0.092	60.95	0.000	8.803
	(1000 kVA and Over)	2.4										
13	Transmission		9,595	2	27,817	4.337	2.492	8.60	0.064	257.52	1.447	8.341
14	Primary		332,798	36	750,256	4.458	3.418	15.16	0.025	193.24	0.027	7.929
15	Secondary		163,236	34	441,957	4.497	3.832	14.15	0.020	79.51	0.000	8.349
16	Total (1000 kVA and Over)	2.4	505,628	72	1,220,030	4.468	3.534	14.65	0.024	141.32	0.045	8.072
17	**STREET LIGHTING**	4.1	31,886	10,655	0	4.500	5.736	0.00	4.933	12.30	32.902	48.070
18	Total		5,898,540	257,252	6,810,736	4.491	5.197		1.345	25.70	0.182	11.215

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

NOTE:
Column
A - See Schedule 4.1, Column D.
B - See Schedule 4.1, Column C.
C - See Schedule 4.1, Column E.
D - [(Total of Energy Related Costs (Schedule 1.3, Column A) divided by Energy Sales (Schedule 1.7, Column A)) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100] plus RSA Loader (Schedule 1.6, Column J).
E - Demand Related Costs (Schedule 1.3, Column B) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
F - Demand Related Costs (Schedule 1.3, Column B) divided by Total Billing Demands (Schedule 1.7, Column C) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000.
G - Customer Related Costs (Schedule 1.3, Column C) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
H - Customer Related Costs (Schedule 1.3, Column C) divided by Average Number of Customers (Schedule 1.7, Column B) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000 divided by 12.
I - Specifically Assigned Costs (Schedule 1.3 Column E) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
J - Total of Columns D, E, G and I.

FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS
(All numbers are times $1,000)

Line			Produced &	Produced &		Distribution											
			Purchased	Purchased	Transmission	Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting	Cust. Acc. &	Specifically
No.	Category	Total	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Cust. Serv.	Assigned
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	176,253	79,173	97,080	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	23,119	23,119	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	124,815	0	0	124,009	0	0	0	0	0	0	0	0	0	0	0	806
	Substations																
4	Hydro Electric Production	9,723	4,368	5,356	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	854	854	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	53,450	0	0	53,211	0	0	0	0	0	0	0	0	0	0	0	238
7	Distribution	134,032	0	0	0	133,673	0	0	0	0	0	0	0	0	0	0	359
	Distribution																
8	Land and Land Clearing	42	0	0	0	0	21	11	0	0	5	3	0	0	2	0	0
9	Conductors, Poles and Fittings	611,231	0	0	0	0	312,035	153,689	0	0	78,009	38,422	0	0	29,076	0	0
10	Transformers	135,300	0	0	0	0	0	0	106,887	28,413	0	0	0	0	0	0	0
11	Services	96,808	0	0	0	0	0	0	0	0	0	0	96,808	0	0	0	0
12	Meters	26,433	0	0	0	0	0	0	0	0	0	0	0	26,433	0	0	0
13	Street lighting	20,206	0	0	0	0	0	0	0	0	0	0	0	0	20,206	0	0
14	Total Direct Utility Plant	1,412,264	107,513	102,436	177,220	133,673	312,056	153,699	106,887	28,413	78,014	38,425	96,808	26,433	49,284	0	1,403
	General Utility Plant																
15	Land and Land Clearing	4,589	130	124	701	343	801	395	274	73	200	99	249	68	127	999	5
16	Buildings	38,762	1,635	1,558	6,329	2,905	6,781	3,340	2,323	617	1,695	835	2,104	574	1,071	6,950	45
17	Computer Equipment	37,572	1,234	1,175	3,767	1,829	4,270	2,103	1,463	389	1,068	526	1,325	362	674	17,361	27
18	Misc Equipment	16,837	633	603	2,960	1,348	3,146	1,550	1,078	286	787	387	976	266	497	2,299	21
19	Transportation	27,162	477	454	3,742	2,701	6,305	3,106	2,160	574	1,576	776	1,956	534	996	1,775	29
20	Tele-communications	9,986	866	825	3,207	507	1,182	582	405	108	296	146	367	100	187	1,190	20
21	Total General Utility Plant	134,908	4,975	4,740	20,706	9,632	22,486	11,075	7,702	2,047	5,622	2,769	6,976	1,905	3,551	30,574	148
22	Total	1,547,173	112,489	107,176	197,926	143,305	334,542	164,774	114,589	30,460	83,636	41,194	103,784	28,338	52,835	30,574	1,551

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and common transmission costs classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and distribution substation common costs classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
14	Total Direct Fixed Plant	Total of Lines 1 through 13.
	General Utility Plant	
15	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
21	Total General Property	Total of Lines 15 through 20.
22	Total	Total of Lines 14 and 21.

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution										Cust. Acc. & Cust. Serv.	Specifically Assigned
						Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting		
						Demand	Demand	Customer	Demand	Customer'	Demand	Customer	Customer	Customer	Customer		
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	60,161	27,024	33,137	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	14,705	14,705	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	59,531	0	0	59,147	0	0	0	0	0	0	0	0	0	0	0	384
	Substations																
4	Hydro Electric Production	2,968	1,333	1,635	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	261	261	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	16,317	0	0	16,244	0	0	0	0	0	0	0	0	0	0	0	73
7	Distribution	40,917	0	0	0	40,807	0	0	0	0	0	0	0	0	0	0	109
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	261,982	0	0	0	0	133,265	65,638	0	0	33,316	16,410	0	0	13,353	0	0
10	Transformers	36,632	0	0	0	0	0	0	28,939	7,693	0	0	0	0	0	0	0
11	Services	64,789	0	0	0	0	0	0	0	0	0	0	64,789	0	0	0	0
12	Meters	1,560	0	0	0	0	0	0	0	0	0	0	0	1,560	0	0	0
13	Street lighting	8,703	0	0	0	0	0	0	0	0	0	0	0	0	8,703	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	14,545	614	585	2,375	1,090	2,544	1,253	872	232	636	313	789	216	402	2,608	17
16	Computer Equipment	20,520	674	642	2,057	999	2,332	1,149	799	212	583	287	723	198	368	9,482	15
17	Misc. Equipment	9,999	376	358	1,758	800	1,868	920	640	170	467	230	580	158	295	1,365	13
18	Transportation	13,149	231	220	1,812	1,308	3,052	1,503	1,046	278	763	376	947	259	482	859	14
19	Tele-communications	7,997	693	660	2,568	406	947	466	324	86	237	117	294	80	150	953	16
20	Total	634,737	45,911	37,237	85,961	45,410	144,010	70,930	32,619	8,671	36,002	17,733	68,122	2,470	23,753	15,267	641

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and common transmission costs classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and distribution substation common costs classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Rights	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	802	0	0	797	0	0	0	0	0	0	0	0	0	0	0	5
	Substations																
4	Hydro Electric Production	74	33	40	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	404	0	0	402	0	0	0	0	0	0	0	0	0	0	0	2
7	Distribution	1,013	0	0	0	1,011	0	0	0	0	0	0	0	0	0	0	3
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	26,409	0	0	0	0	13,482	6,640	0	0	3,370	1,660	0	0	1,256	0	0
10	Transformers	1,859	0	0	0	0	0	0	1,469	390	0	0	0	0	0	0	0
11	Services	1,002	0	0	0	0	0	0	0	0	0	0	1,002	0	0	0	0
12	Meters	766	0	0	0	0	0	0	0	0	0	0	0	766	0	0	0
13	Street lighting	469	0	0	0	0	0	0	0	0	0	0	0	0	469	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Misc. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Tele-communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total	32,806	39	40	1,200	1,011	13,482	6,640	1,469	390	3,370	1,660	1,002	766	1,726	0	10

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and common transmission costs classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and distribution substation common costs classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23. Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production. Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related
1	Hydro Electric Production	116,092	52,149	63,943	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	8,414	8,414	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	65,283	0	0	64,862	0	0	0	0	0	0	0	0	0	0	0	422	0
	Substations																	
4	Hydro Electric Production	6,755	3,034	3,721	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	593	593	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	37,133	0	0	36,967	0	0	0	0	0	0	0	0	0	0	0	166	0
7	Distribution	93,115	0	0	0	92,866	0	0	0	0	0	0	0	0	0	0	249	0
	Distribution																	
8	Land and Land Clearing	42	0	0	0	0	21	11	0	0	5	3	0	0	2	0	0	0
9	Conductors, Poles and Fittings	349,248	0	0	0	0	178,769	88,051	0	0	44,692	22,013	0	0	15,724	0	0	0
10	Transformers	98,668	0	0	0	0	0	0	77,948	20,720	0	0	0	0	0	0	0	0
11	Services	32,019	0	0	0	0	0	0	0	0	0	0	32,019	0	0	0	0	0
12	Meters	24,873	0	0	0	0	0	0	0	0	0	0	0	24,873	0	0	0	0
13	Street lighting	11,503	0	0	0	0	0	0	0	0	0	0	0	0	11,503	0	0	0
14	Total Direct Net Utility Plant	843,738	64,190	67,664	101,829	92,866	178,791	88,061	77,948	20,720	44,698	22,015	32,019	24,873	27,228	0	836	0
	General Plant																	
15	Land and Land Rights	4,589	130	124	701	343	801	395	274	73	200	99	249	68	127	999	5	0
16	Buildings	24,217	1,022	974	3,954	1,815	4,236	2,087	1,451	386	1,059	522	1,314	359	669	4,342	28	0
17	Computer Equipment	17,052	560	533	1,709	830	1,938	955	664	176	484	239	601	164	306	7,879	12	0
18	Misc. Equipment	6,838	257	245	1,202	547	1,278	629	438	116	319	157	396	108	202	934	9	0
19	Transportation	14,013	246	234	1,931	1,393	3,253	1,602	1,114	296	813	401	1,009	276	514	916	15	0
20	Tele-communications	1,989	172	164	639	101	236	116	81	21	59	29	73	20	37	237	4	0
21	Total General Plant	68,699	2,388	2,275	10,136	5,030	11,742	5,783	4,022	1,069	2,935	1,446	3,643	995	1,854	15,307	73	0
22	Total Net Utility Plant	912,436	66,577	69,939	111,965	97,896	190,533	93,844	81,969	21,789	47,633	23,461	35,662	25,867	29,083	15,307	910	0
	Deductions from Rate Base																	
23	Contributions in Aid of Construction	32,806	39	40	1,200	1,011	13,482	6,640	1,469	390	3,370	1,660	1,002	766	1,726	0	10	0
24	Security Deposits	750	51	47	86	65	117	58	36	10	29	14	65	10	34	125	1	0
25	Post Retirement Benefits Liability	32,455	2,224	2,050	3,733	2,823	5,064	2,494	1,574	418	1,266	624	2,831	420	1,479	5,428	27	0
26	Future Income Taxes - Depreciation/CCA	8,341	609	639	1,023	895	1,742	858	749	199	435	214	326	236	266	140	8	0
27	Future Income Taxes - Pension/OPEBS	(6,140)	(421)	(388)	(706)	(534)	(958)	(472)	(298)	(79)	(239)	(118)	(536)	(79)	(280)	(1,027)	(5)	0
28	Demand Management Incentive Liability	87	87	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Deductions	68,298	2,589	2,390	5,336	4,259	19,446	9,578	3,531	939	4,862	2,395	3,688	1,352	3,225	4,667	41	0
	Additions to Rate Base																	
30	Average Deferred Charges	102,687	7,036	6,487	11,812	8,931	16,021	7,891	4,981	1,324	4,005	1,973	8,956	1,328	4,681	17,175	86	0
31	Unamortized Cost Recovery Deferrals	8,308	569	525	956	723	1,296	638	403	107	324	160	725	107	379	1,389	7	0
32	Customer Financing Programs	1,250	86	79	144	109	195	96	61	16	49	24	109	16	57	209	1	0
33	Weather Normalization (hydro equal.)	(2,149)	0	(2,149)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Weather Normalization (Degree Day Norm.)	(1,201)	(120)	(126)	(201)	(176)	(343)	0	(147)	0	(86)	0	0	0	0	0	(2)	0
35	Cash Working Capital Allowance	6,404	444	437	690	525	945	465	299	79	236	116	511	81	270	968	5	332
36	Materials And Supplies	5,619	194	185	1,380	503	1,174	578	402	107	293	145	364	99	185	0	9	0
37	Total Additions	120,917	8,208	5,438	14,780	10,614	19,288	9,669	5,998	1,634	4,822	2,417	10,665	1,631	5,572	19,741	107	332
38	Total Average Rate Base	965,055	72,196	72,988	121,409	104,250	190,375	93,935	84,437	22,484	47,594	23,484	42,638	26,146	31,429	30,382	976	332

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
2	Other Generation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
3	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
	Substations	
4	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
5	Other Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
6	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
7	Distribution	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
	Distribution	
8	Land and Land Clearing	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
9	Conductors, Poles and Fittings	
10	Transformers	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
11	Services	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
12	Meters	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
13	Street lighting	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
14	Total Direct Net Utility Plant	Total of Line 1 to 13.
	General Plant	
15	Land and Land Rights	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
16	Buildings	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
17	Computer Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
18	Misc. Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
19	Transportation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
20	Tele-communications	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
21	Total General Plant	Total of Lines 15 to 20.
22	Total Net Utility Plant	Total of Line 14 and Line 21.
	Deductions from Rate Base	
23	Contributions in Aid of Construction	Taken from totals shown on Schedule 2.3.
24	Security Deposits	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
25	Post Retirement Benefits Liability	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
26	Future Income Taxes - Depreciation/CCA	Functional Classification based on Total Net Utility Plant (Line 22).
27	Future Income Taxes - Pension/OPEBS	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
28	DMI Liability	Functional Classification Classified 100% to Produced and Purchased Demand.
29	Total Deductions	Total of Lines 23 through 28.
	Additions to Rate Base	
30	Average Deferred Charges	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
31	Unamortized Cost Recovery Deferrals	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
32	Customer Financing Programs	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 29).
33	Weather Normalization (hydro equal.)	Classified 100% to Energy.
34	Weather Normalization (Degree Day Norm.)	Functional Classification split based on Total Net Utility Plant (Line 22) excluding Customer Classification Functions
35	Cash Working Capital Allowance	Functional Classification based on total operating and maintenance shown on Schedule 1.1, line 1 plus line 2.
36	Materials And Supplies	Functionalized based on Year End Inventory (See Schedule 5.1 Line 31). Classification based on total direct utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned (Schedule 2.1).
37	Total Additions	Total of Lines 30 through 36.
38	Total Rate Base	Line 22 less Line 29 plus Line 37.

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses Total	Labour	Non-Labour	Non-Regulated Expenses	Excluding Non-Regulated Expenses Total Excl.	Labour Excl.	Non-Labour Excl.
	PURCHASED POWER WEATHER ADJUSTED							
PPH	Nfld. Hydro - Firm	434,780	-	434,780	-	434,780	-	434,780
PPDL	Nfld. Hydro - Secondary	-	-	-	-	-	-	-
	TOTAL PURCHASED POWER	434,780	-	434,780	-	434,780	-	434,780
	PRODUCTION							
Hydro	Hydro - Direct Operating and Maintenance	1,765	1,019	746	-	1,765	1,019	746
Hydro	Hydro - Water and Fuel - Lubricants	77	-	77	-	77	-	77
Hydro	Hydro - Supervision and misc.	677	490	187	-	677	490	187
Oth Prod	Other Production - Direct Operating and Maintenance	405	308	96	-	405	308	96
Oth Prod	Other Production - Fuel and Lubricants	61	-	61	-	61	-	61
	TOTAL PRODUCTION	2,985	1,817	1,168	-	2,985	1,817	1,168
Gen Sys Opr	SYSTEM OPERATIONS	1,215	1,112	103	-	1,215	1,112	103
Gen PTD	TOOLS, SAFETY, EQUIPMENT REPAIR & RUBBER GLOVE TESTING	706	7	698	-	706	7	698
Gen PTD	GENERAL OPERATIONS	5,088	4,480	608	-	5,088	4,480	608
	TOTAL MISC TECHNICAL OPERATING COSTS	7,009	5,600	1,409	-	7,009	5,600	1,409
Gen PTD	ENVIRONMENTAL COST	211	154	56	-	211	154	56
	SUBSTATIONS							
Subs	Direct O&M	2,733	2,021	712	-	2,733	2,021	712
	TRANSMISSION							
Transm	Direct O&M	1,342	317	1,025	-	1,342	317	1,025
	DISTRIBUTION							
CPF	Direct O&M - Lines/poles/fittings	2,833	2,577	256	-	2,833	2,577	256
Services	Direct O&M - Services	2,772	2,721	51	-	2,772	2,721	51
Strlgts	Direct O&M - Street Lights	1,481	823	659	-	1,481	823	659
Transf.	Direct O&M - Transformers	288	271	17	-	288	271	17
Meters	Direct O&M - Meters	112	80	31	-	112	80	31
Gen D	Direct O&M - Vegetation Management	891	142	749	-	891	142	749
Gen D	Power Quality	-	-	-	-	-	-	-
Gen D	Distribution Line Inspections	192	186	6	-	192	186	6
Gen D	Pre Issues	268	-	268	-	268	-	268
	TOTAL DISTRIBUTION	8,837	6,801	2,036	-	8,837	6,801	2,036
	COMMUNICATIONS							
Gen Comm	Direct O&M - General	1,547	15	1,532	-	1,547	15	1,532
Gen Comm	Direct O&M - Supervisory Contol Systems	-	-	-	-	-	-	-
	TOTAL COMMUNICATIONS	1,547	15	1,532	-	1,547	15	1,532
	CUSTOMER SERVICE							
Cust Acc	Customer Service Administration, Billing & Meter Reading	3,652	3,223	429	23	3,629	3,202	427
Cust Acc	Credit, Collections & Cash Control	2,467	742	1,726		2,467	742	1,726

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses			Non-Regulated	Excluding Non-Regulated Expenses		
		Total	Labour	Non-Labour	Expenses	Total Excl.	Labour Excl.	Non-Labour Excl.
Cust Acc	Inquiry	3,622	3,566	56		3,622	3,566	56
Cust Acc	Uncollectable Bills	1,490	-	1,490	-	1,490	-	1,490
CDM - GA	Conservation and Demand Management - General Activities	804	521	283		804	521	283
CDM - Prom	Conservation and Demand Management - Program Costs	4,855	1,049	3,807		4,855	1,049	3,807
CDM - DM	Curtailable Service Option	255	8	247		255	8	247
CDM - Prom	Conservation and Demand Management - Program Costs Deferred	(4,436)	(950)	(3,486)		(4,436)	(950)	(3,486)
	TOTAL CUSTOMER SERVICE	12,710	8,157	4,553	23	12,687	8,137	4,550
	FINANCE							
A&G	Finance	1,519	1,317	202		1,519	1,317	202
Labour Rela	Company Pension Scheme	11,806	(100)	11,906		11,806	(100)	11,906
Labour Rela	Other Post Retirement Benefits	10,968	-	10,968		10,968	-	10,968
	TOTAL FINANCE	24,293	1,217	23,076	-	24,293	1,217	23,076
A&G	CORPORATE COMMUNICATIONS	1,037	489	548	21	1,016	478	537
	MANAGEMENT INFORMATION SYSTEMS							
A&G	Computer Operations	829	724	105	-	829	724	105
A&G	Systems Development and Support	2,540	1,150	1,390	-	2,540	1,150	1,390
	TOTAL MIS	3,370	1,874	1,495	-	3,370	1,874	1,495
	HUMAN RESOURCE AND EMPLOYEE RELATED COSTS							
A&G	Human Resources Division	2,273	1,871	402	-	2,273	1,871	402
A&G	Employee Welfare & Coffee & Lunchroom Supplies	272	9	263	-	272	9	263
	TOTAL HUMAN RESOURCE AND EMPLOYEE RELATED COSTS	2,545	1,881	664	-	2,545	1,881	664
	ADMINSTRATION & MISCELLANEOUS							
A&G	Administration, Support Staff and Internal Audit	8,298	4,075	4,223	2,428	5,870	2,883	2,987
A&G	Misc. Costs - General	1,075	470	605	328	747	327	420
Ins & Dam.	Misc. Costs - Property Insurace & Public Liability (Not Insured)	1,599	97	1,503	-	1,599	97	1,503
Cust Acc	Mail Room	10	-	10	-	10	-	10
Revenue Related	PUB Assessments	881	-	881	-	881	-	881
A&G	Property Maintenance	1,582	163	1,419	-	1,582	163	1,419
A&G	Printing Services	240	148	92	-	240	148	92
	TOTAL ADMINISTRATION & MISCELLANEOUS	13,686	4,954	8,732	2,756	10,930	3,618	7,312
Vehicles	VEHICLE MAINTENANCE	1,910	-	1,910	-	1,910	-	1,910
	TOTAL OPERATING AND MAINTENANCE EXPENSES Net of GEC & (Excluding RSA & MTA Expense)	518,994	35,296	483,697	2,801	516,193	33,930	482,263

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses			Non-Regulated	Excluding Non-Regulated Expenses		
		Total	Labour	Non-Labour	Expenses	Total Excl.	Labour Excl.	Non-Labour Excl.

Expense Category Code	Cost of Service Expense Category
A&G	Administration and General (Excluding Labour Related Costs).
CDM - GA	Conservation and Demand Management - General Activities
CDM - Prom	Conservation and Demand Management - Program Costs
CDM - DM	Curtailable Service Option and Voltage Management
Curtail	Curtailable Credits Paid Customers.
CPF	Operating expenses directly associated with Conductors, Poles and Fittings.
Cust Acc	Operating Expenses associated with Customer Accounting and Customer Service.
Gen Comm	Communication Expenses Related to the VHS/Mobile radio system.
Gen D	General expenses to be split over the categories within distribution.
Gen PTD	General expenses to be split over Production, Transmission and Distribution.
Gen Sys Opr	General expenses associated with the Systems Control Centre.
Gen TD	General expenses to be split over Transmission and Distribution.
Hydro	Operating expenses associated with Hydraulic Generation.
Labour Rela	Administration and general Expenses directly related to Labour.
Meters	Operating expenses directly associated with Meters.
Oth Prod	Operating expenses associated with Diesel and Gas Turbine Generation.
Ins & Dam.	Property Insurance, Public Liability, Risk Management.
PPDL	Purchase Power Costs for Secondary Energy from Deer Lake Power Firmed up by Hydro.
PPH	Purchase Power Costs from Hydro for Firm Energy.
Revenue Related	Operating expenses related to revenue.
Services	Operating expenses directly associated with Services.
Strlgts	Operating expenses directly associated with Street Lighting.
Subs	Operating expenses directly associated with Substations.
Transf.	Operating expenses directly associated with Transformers.
Transm	Operating expenses directly associated with Transmission.
Vehicles	Operating expenses directly associated with Vehicles.

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES
(All numbers are times $1000)

Line No.	Catagory	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Customer Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
	Purchase Power Expense																	
1	Purchases from Hydro - Production related	345,791	117,961	227,830	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Purchases from Hydro - Transmission related	29,855	29,855	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Deer Lake Power Secondary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Demand Mangement Incentive Account	628	628	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Amortization of Degree Day Reserve	(983)	(98)	(103)	(165)	(144)	(281)	0	(121)	0	(70)	0	0	0	0	0	(1)	0
6	Sub Total	375,291	148,346	227,727	(165)	(144)	(281)	0	(121)	0	(70)	0	0	0	0	0	(1)	0
	Direct Operating & Maintenance Expense																	
7	Hydraulic Production	2,519	1,131	1,387	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Other Production	466	466	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Transmission	1,342	0	0	1,333	0	0	0	0	0	0	0	0	0	0	0	9	0
	Substations																	
10	Hydarulic Plants	134	60	74	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Other Production	12	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Transmission	738	0	0	734	0	0	0	0	0	0	0	0	0	0	0	3	0
13	Distribution	1,849	0	0	0	1,844	0	0	0	0	0	0	0	0	0	0	5	0
	Distribution																	
14	Lines/poles/fittings	2,833	0	0	0	0	1,518	748	0	0	380	187	0	0	0	0	0	0
15	Services	2,772	0	0	0	0	0	0	0	0	0	0	2,772	0	0	0	0	0
16	Street Lights	1,481	0	0	0	0	0	0	0	0	0	0	0	0	1,481	0	0	0
17	Transformers	288	0	0	0	0	0	0	227	60	0	0	0	0	0	0	0	0
18	Meters	112	0	0	0	0	0	0	0	0	0	0	0	112	0	0	0	0
19	Customer Accounting	11,219	0	0	0	0	0	0	0	0	0	0	0	0	0	11,219	0	0
20	Subtotal Direct O&M	25,764	1,669	1,461	2,067	1,844	1,518	748	227	60	380	187	2,772	112	1,481	11,219	17	0
	General System Expenses																	
21	Related to Distribution	1,351	0	0	0	208	345	170	104	28	86	43	222	28	117	0	1	0
22	Related to Prod, Trans. & Distribution	6,004	536	491	810	640	1,064	524	319	85	266	131	685	87	360	0	6	0
23	Related to Vehicles	1,910	34	32	263	190	443	218	152	40	111	55	138	38	70	125	2	0
24	System Control Centre Expenses	1,215	126	116	453	80	133	65	40	11	33	16	86	11	45	0	0	0
25	General Communication Expenses	1,547	71	65	283	119	198	97	59	16	49	24	127	16	67	354	0	0
26	Subtotal General System Expenses	12,028	767	704	1,810	1,237	2,183	1,075	674	179	546	269	1,258	181	658	479	9	0
	Administration and General																	
27	Insurance, Injuries & Damages	1,599	117	123	196	172	334	164	144	38	83	41	63	45	51	27	2	0
28	Labour Related	22,774	1,560	1,439	2,620	1,981	3,553	1,750	1,105	294	888	438	1,986	294	1,038	3,809	19	0
29	Other Administration And General Expenses	16,889	1,157	1,067	1,943	1,469	2,635	1,298	819	218	659	324	1,473	218	770	2,825	14	0
30	Amortization - 2013 General Cost Deferral	1,586	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,586
31	Amortization - 2011 and 2012 General Cost Deferrals	1,575	108	99	181	137	246	121	76	20	61	30	137	20	72	263	1	0
32	Amortization - 2012 Cost of Capital Deferral	829	57	52	95	72	129	64	40	11	32	16	72	11	38	139	1	0
33	PUB Assessments	881	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	881
34	Subtotal Administration and General Expenses	46,132	2,999	2,780	5,035	3,830	6,897	3,397	2,184	581	1,724	849	3,731	589	1,969	7,063	37	2,467
	CDM Activities																	
35	CDM - General Activities	804	55	51	92	70	125	62	39	10	31	15	70	10	37	134	1	0
36	CDM - Program Costs	420	0	420	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Curtailable Service Option	255	247	0	3	3	2	0	0	0	1	0	0	0	0	0	0	0
38	Subtotal CDM Activities	1,479	302	470	96	73	127	62	39	10	32	15	70	10	37	134	1	0
39	Total O&M (less RSA, MTA and Rural Deficit)	460,694	154,084	233,142	8,842	6,840	10,445	5,282	3,004	831	2,611	1,320	7,832	892	4,145	18,895	62	2,467

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES

Line No.	Category	Basis for Functional Classification
	Column A - Total	From Schedule 3.1 less rural deficit plus regulatory deferrals (Lines 30, 31 & 32)
	Purchase Power Expense	Excludes the rural deficit of $59,488,702
1	Purchases from Hydro - Production related	Based on functional classification splits shown in Schedule 5.1, Line 1. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
2	Purchases from Hydro - Transmission related	Based on functional classification splits shown in Schedule 5.1, Line 2. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
3	Deer Lake Power Secondary	Based on functional classification splits shown in Schedule 5.1, Line 3.
4	Demand Mangement Incentive Account	Classification based on 100% Purchase Power Demand
5	Amortization of Degree Day Reserve	Functional Classification split based on Total Net Utility Plant (Schedule 2.4, Line 22) excluding Customer Classification Functions
6	Sub Total	Total of Lines 1 - 5.
	Direct Operating & Maintenance Costs	
7	Hydraulic Production	Based on classification splits shown in Schedule 5.1, Line 4.
8	Other Production	Based on classification splits shown in Schedule 5.1, Line 5.
9	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
10	Hydarulic Plants	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
11	Other Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
12	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
13	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
14	Lines/poles/fittings	Functional splits based on schedule 5.1 line 22 (excluding street lighting) and classified as shown in schedule 5.1 lines 11 & 12.
15	Services	Classified as shown in schedule 5.1 line 15.
16	Street Lights	Classified as shown in schedule 5.1 line 17.
17	Transformers	Classified as shown in schedule 5.1 line 14..
18	Meters	Classified as shown in schedule 5.1 line 16.
19	Customer Accounting	Classified 100% to Customer Accounting (Customer).
20	Subtotal Direct O&M	Total of Lines, 7 to 19.
	General System Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Line 20). The weighting used is: 50.9% operating, and 49.1% capital.

	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	6.9%	6.3%	10.4%	8.2%	13.6%	6.7%	4.1%	1.1%	3.4%	1.7%	8.8%	1.1%	4.6%	23.1%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
21	Related to Distribution	Functional Classification based on the weighted split shown for Columns E through N & the distribution portion of Column P.
22	Related to Prod, Trans. & Distribution	Functional Classification based on the weighted split shown for Columns B through N & P.
23	Related to Vehicles	Functional Classification based on splits for vehicle fixed assets (see schedule 2.4 line 19).
24	System Control Centre Expenses	Functionalized based on a study of SCADA plant (see Schedule 5.1, Line 29). Classification based on functional categories shown for general system expenses in columns B through N.
25	General Communications Expenses	Functionalized based on a study of Communications Expenses (see Schedule 5.1, Line 30). Classification based on functional categories shown for general system expenses in columns B through O.
26	Subtotal General System Expenses	Total of all Lines 21 to 25.
	Administration and General Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Lines 20 plus 26). The weighting used is: 50.9% operating, and 49.1% capital.

Split for Administration and General

	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Primary Demand	Primary Customer	Transformers Demand	Transformers Customer	Secondary Demand	Secondary Customer	Services Customer	Meters Customer	St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	6.9%	6.3%	11.5%	8.7%	15.6%	7.7%	4.9%	1.3%	3.9%	1.9%	8.7%	1.3%	4.6%	16.7%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
27	Insurance, Injuries & Damages	Functional Classification based on Net Utility Plant in Service (See Schedule 2.4, Line 22)
28	Labour Related	Functional Classification based on the Weighted Split for Administration and General.
29	Other Administration And General Expenses	Functional Classification based on the Weighted Split for Administration and General.
30	Amortization - 2013 General Cost Deferral	Assigned 100% as Revenue Related.
31	Amortization - 2011 and 2012 General Cost Deferrals	Functional Classification based on the Weighted Split for Administration and General.
32	Amortization - 2012 Cost of Capital Deferral	Functional Classification based on the Weighted Split for Administration and General.
33	PUB Assessments	Assigned 100% as Revenue Related.
34	Subtotal Administration and General	Total for Lines 27 to 33.
35	CDM - General Activities	Functional Classification based on the Weighted Split for Administration and General.
36	CDM - Program Costs	Functional Classification based 100% avoided energy supply cost
37	Curtaible Service Option	Functional Classification based on direct O&M classified to demand including purchase power.
38	Subtotal CDM Activities	Total for Lines 35 to 37
39	Total O&M	Totals of Lines 6, 20, 26, 34 and 38.

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution										Cust. Acc. & Cust. Serv.	Specifically Assigned
						Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting		
						Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer		
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Hydro Electric Production	4,357	1,957	2,400	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	1,286	1,286	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	3,947	0	0	3,921	0	0	0	0	0	0	0	0	0	0	0	25
	Substations																
4	Hydro Electric Production	248	111	137	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	22	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	1,363	0	0	1,357	0	0	0	0	0	0	0	0	0	0	0	6
7	Distribution	3,419	0	0	0	3,410	0	0	0	0	0	0	0	0	0	0	9
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	16,643	0	0	0	0	8,496	4,185	0	0	2,124	1,046	0	0	792	0	0
10	Transformers	3,783	0	0	0	0	0	0	2,989	794	0	0	0	0	0	0	0
11	Services	3,136	0	0	0	0	0	0	0	0	0	0	3,136	0	0	0	0
12	Meters	1,336	0	0	0	0	0	0	0	0	0	0	0	1,336	0	0	0
13	Street lighting	1,210	0	0	0	0	0	0	0	0	0	0	0	0	1,210	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	845	36	34	138	63	148	73	51	13	37	18	46	13	23	152	1
16	Computer Equipment	4,044	133	127	405	197	460	226	157	42	115	57	143	39	73	1,869	3
17	Misc. Equipment	709	27	25	125	57	132	65	45	12	33	16	41	11	21	97	1
18	Transportation	2,595	46	43	358	258	602	297	206	55	151	74	187	51	95	170	3
19	Tele-communications	346	30	29	111	18	41	20	14	4	10	5	13	3	6	41	1
20	Total	49,288	3,647	2,794	6,415	4,002	9,879	4,866	3,462	920	2,470	1,217	3,565	1,453	2,220	2,328	49

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
5	Other Production	Functional splits on based schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
6	Transmission	Functional splits based on schedule 5.1 line 20 and common transmission costs classified as shown in schedule 5.1 line 6.
7	Distribution	Functional splits based on schedule 5.1 line 20 and distribution substation common costs classified as shown in schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on schedule 5.1 line 21 and classified as shown in schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on schedule 5.1 line 22 and classified as shown in schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in schedule 5.1 line 14.
11	Services	Classified as shown in schedule 5.1 line 15.
12	Meters	Classified as shown in schedule 5.1 line 16.
13	Street lighting	Classified as shown in schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

CUSTOMER STATISTICS

Line No.	Class of Service	Rate Class	BILLING INFORMATION: Number of Customers At Year End 2013	2014	Average	2014 Energy Sales kWh	2014 Total Billing Demands kW \ kVA	Non-coincident Maximum Class Demands (NCP): Estimated Class Load Factor	Class NCP Demand kW	Class Demand Coincident with System Peak (1CP): Estimated Class Load Factor	Class 1CP Demand kW
			A	B	C	D	E	F	G	H	I
	DOMESTIC										
1	Domestic Regular	1.1	76,549	75,586	76,068	836,962,000	0	43.0%	222,194	51.8%	184,447
2	Domestic All Electric	1.1	145,446	149,238	147,342	2,776,133,000	0	47.9%	661,608	46.8%	677,158
	GENERAL SERVICE										
3	(0-10 kW)	2.1	12,366	12,441	12,404	98,589,000	0	50.9%	22,111	65.2%	17,261
4	(10-100 kW)	2.1	9,432	9,572	9,502	684,210,000	2,582,616	52.6%	148,491	59.7%	130,831
	(110-350 kVA)	2.3									
5	Primary		27	26	27	18,991,539	50,892	56.7%	3,824	68.4%	3,170
6	Secondary		894	929	912	484,612,461	1,614,720	56.7%	97,568	68.4%	80,879
	(350-1000 kVA)	2.3									
7	Transmission		2	2	2	2,348,814	12,372	56.7%	473	68.4%	392
8	Primary		42	43	43	99,212,139	262,824	56.7%	19,975	68.4%	16,558
9	Secondary		209	241	225	359,967,046	1,067,282	56.7%	72,473	68.4%	60,076
	(1000 kVA and Over)	2.4									
10	Transmission		2	1	2	9,594,790	27,817	66.2%	1,655	74.4%	1,472
11	Primary		36	35	36	332,797,508	750,256	66.2%	57,388	74.4%	51,063
12	Secondary		34	34	34	163,235,702	441,957	66.2%	28,148	74.4%	25,046
13	**STREET LIGHTING**	4.1	10,579	10,731	10,655	31,886,000	0	48.0%	7,583	48.0%	7,583
14	Total		255,618	258,879	257,252	5,898,540,000	6,810,736	50.1%	1,343,490	53.6%	1,255,937

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

ENERGY AND DEMAND LOSS FACTORS[1]
(Losses as a percentage of delivered)

Demand Loss Factors

Transmission	1.4632%
Primary	3.9532%
Secondary	2.9398%

Energy Loss Factors

Transmission	0.9580%
Primary	2.6120%
Secondary	2.3749%

(1) Based on a three year average (2012 to 2014)

DEVELOPMENT OF CUSTOMER COST ALLOCATORS

Line No.	Class of Service	Rate Code	Average Number of Customers	Customer Related Costs: Weighting Factor	Customer Related Costs: Weighted Number of Customer	Customer Related Costs: Allocation Factors	Primary Lines: Weighting Factor	Primary Lines: Weighted Number of Customer	Primary Lines: Allocation Factors	Secondary Lines: Weighting Factor	Secondary Lines: Weighted Number of Customer	Secondary Lines: Allocation Factors	Transformers: Weighting Factor	Transformers: Weighted Number of Customer	Transformers: Allocation Factors	Service Drops: Weighting Factor	Service Drops: Weighted Number of Customer	Service Drops: Allocation Factors	Meters: Weighting Factor	Meters: Weighted Number of Customer	Meters: Allocation Factors
			A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
	DOMESTIC																				
1	Domestic Regular	1.1	76,068	1.0	76,068	29.541%	1.0	76,068	29.570%	1.0	76,068	29.582%	1.0	76,068	28.219%	1.0	76,068	30.718%	1.0	76,068	23.033%
2	Domestic All Electric	1.1	147,342	1.0	147,342	57.219%	1.0	147,342	57.276%	1.0	147,342	57.300%	1.0	147,342	54.659%	1.0	147,342	59.500%	1.0	147,342	44.615%
	GENERAL SERVICE																				
3	(0-10 kW)	2.1	12,404	1.1	13,644	5.299%	1.0	12,404	4.822%	1.0	12,404	4.824%	1.2	14,885	5.522%	1.0	12,404	5.009%	1.5	18,606	5.634%
4	(10-100 kW)	2.1	9,502	1.6	15,203	5.904%	1.0	9,502	3.694%	1.0	9,502	3.695%	1.8	17,104	6.345%	1.1	10,452	4.221%	6.0	57,012	17.263%
	(110-350 kVA)	2.3																			
5	Primary		27	1.6	43	0.017%	1.0	27	0.010%	-	-	0.000%	-	-	0.000%	-	-	0.000%	107.5	2,903	0.879%
6	Secondary		912	1.6	1,459	0.567%	1.0	912	0.355%	1.0	912	0.355%	3.0	2,736	1.015%	1.5	1,368	0.552%	15.1	13,771	4.170%
	(350-1000 kVA)	2.3																			
7	Transmission		2	1.6	3	0.001%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	167.2	334	0.101%
8	Primary		43	1.6	69	0.027%	1.0	43	0.017%	-	-	0.000%	-	-	0.000%	-	-	0.000%	107.5	4,623	1.400%
9	Secondary		225	1.6	360	0.140%	1.0	225	0.087%	1.0	225	0.088%	3.0	675	0.250%	-	-	0.000%	15.1	3,398	1.029%
	(1000 kVA and Over)	2.4																			
10	Transmission		2	1.6	3	0.001%	0.0	-	0.000%	-	-	0.000%	-	-	0.000%	-	-	0.000%	177.6	355	0.108%
11	Primary		36	1.6	58	0.022%	1.0	36	0.014%	-	-	0.000%	-	-	0.000%	-	-	0.000%	125.7	4,525	1.370%
12	Secondary		34	1.6	54	0.021%	1.0	34	0.013%	1.0	34	0.013%	3.0	102	0.038%	-	-	0.000%	38.8	1,319	0.399%
13	**STREET LIGHTING**	4.1	10,655	0.3	3,197	1.241%	1.0	10,655	4.142%	1.0	10,655	4.144%	1.0	10,655	3.953%	-	-	0.000%	-	-	0.000%
14	Total		257,252		257,504	100.0%		257,248	100.0%		257,142	100.0%		269,566	100.0%		247,634	100.0%		330,256	100.0%

NOTES:

Column

A - See Schedule 4.1, Column C.
B - Weighting Factors estimated based on general review of Customer accounting and Customer service activities.
C - Column A times B.
D - Class weighted number of customers divided by the total number of weighted customers for Column C.
E - Equal weighting assigned to all Customers supplied through primary lines.
F - Column A times E.
G - Class weighted number of customers divided by the total number of weighted customers for Column F.
H - Equal weighting assigned to all Customers supplied through secondary lines.
I - Column A times H.
J - Class weighted number of customers divided by the total number of weighted customers for Column I.
K - by 1.5% due to reported demand sales being based at secondary sales levels.
L - Column A times K.
M - Class weighted number of customers divided by the total number of weighted customers for Column L.
N - Based on typical costs to provide Service Drops for customers within each class.
O - Column A times N.
P - Class weighted number of customers divided by the total number of weighted customers for Column O.
Q - Based on typical cost to provide metering for customers within each class.
R - Column A times Q.
S - Class weighted number of customers divided by the total number of weighted customers for Column R.

DEVELOPMENT OF ENERGY ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Energy Allocator: Load at Meter kWh	Secondary Energy Allocator: Secondary Energy Loss Factor	Secondary Energy Allocator: Load at Secondary Input kWh	Secondary Energy Allocator: Secondary Allocation Factor	Primary Energy Allocator: Load at Primary Output kWh	Primary Energy Allocator: Primary Energy Loss Factor	Primary Energy Allocator: Load at Primary Input kWh	Primary Energy Allocator: Primary Allocation Factor	Transmission Energy Allocator: Load at Transmission Output kWh	Transmission Energy Allocator: Transmission Energy Loss Factor	Transmission Energy Allocator: Load at Transmission Input kWh	Transmission Energy Allocator: Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	836,962,000	0.023749	856,839,011	15.398%	856,839,011	0.026120	879,219,645	14.227%	879,219,645	0.009580	887,642,570	14.200%
2	Domestic All Electric	1.1	2,776,133,000	0.023749	2,842,063,383	51.073%	2,842,063,383	0.026120	2,916,298,078	47.191%	2,916,298,078	0.009580	2,944,236,214	47.099%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	98,589,000	0.023749	100,930,390	1.814%	100,930,390	0.026120	103,566,692	1.676%	103,566,692	0.009580	104,558,861	1.673%
4	(10-100 kW)	2.1	684,210,000	0.023749	700,459,303	12.588%	700,459,303	0.026120	718,755,300	11.631%	718,755,300	0.009580	725,640,976	11.608%
	(110-350 kVA)	2.3												
5	Primary		-	0.023749	-	0.000%	19,276,412	0.026120	19,779,912	0.320%	19,779,912	0.009580	19,969,403	0.319%
6	Secondary		484,612,461	0.023749	496,121,523	8.916%	496,121,523	0.026120	509,080,217	8.238%	509,080,217	0.009580	513,957,205	8.222%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.023749	-	0.000%	-	0.026120	-	0.000%	2,384,046	0.009580	2,406,886	0.039%
8	Primary		-	0.023749	-	0.000%	100,700,321	0.026120	103,330,614	1.672%	103,330,614	0.009580	104,320,521	1.669%
9	Secondary		359,967,046	0.023749	368,515,904	6.622%	368,515,904	0.026120	378,141,539	6.119%	378,141,539	0.009580	381,764,135	6.107%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.023749	-	0.000%	-	0.026120	-	0.000%	9,738,711	0.009580	9,832,008	0.157%
11	Primary		-	0.023749	-	0.000%	337,789,471	0.026120	346,612,532	5.609%	346,612,532	0.009580	349,933,080	5.598%
12	Secondary		163,235,702	0.023749	167,112,387	3.003%	167,112,387	0.026120	171,477,363	2.775%	171,477,363	0.009580	173,120,116	2.769%
13	**STREET LIGHTING**	4.1	31,886,000	0.023749	32,643,261	0.587%	32,643,261	0.026120	33,495,903	0.542%	33,495,903	0.009580	33,816,793	0.541%
14	Total		5,435,595,210	0.023749	5,564,685,161	100.00%	6,022,451,365	0.026120	6,179,757,794	100.000%	6,191,880,552	0.009580	6,251,198,768	100.000%

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

DEVELOPMENT OF ENERGY ALLOCATORS

NOTES:

A - See Schedule 4.1, Column D.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C and includes customers that are supplied at primary level as shown in Schedule 4.1. Energy Sales increased
 - by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Energy Sales increased
 - by 1.5% due to reported energy sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Demand Allocator: Load at Meter kW A	Secondary Demand Loss Factor B	Load at Secondary Input kW C	Secondary Allocation Factor D	Primary Demand Allocator: Load at Primary Output kW E	Primary Demand Loss Factor F	Load at Primary Input kW G	Primary Allocation Factor H	Transmission Demand Allocator: Load at Transmission Output kW I	Transmission Demand Loss Factor J	Load at Transmission Input kW K	Transmission Allocation Factor L
	DOMESTIC													
1	Domestic Regular	1.1	222,194	0.029398	228,727	17.632%	228,727	0.039532	237,769	16.579%	237,769	0.014632	241,248	16.554%
2	Domestic All Electric	1.1	661,608	0.029398	681,058	52.501%	681,058	0.039532	707,981	49.365%	707,981	0.014632	718,341	49.291%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	22,111	0.029398	22,761	1.755%	22,761	0.039532	23,661	1.650%	23,661	0.014632	24,007	1.647%
4	(10-100 kW)	2.1	148,491	0.029398	152,856	11.783%	152,856	0.039532	158,899	11.080%	158,899	0.014632	161,224	11.063%
	(110-350 kVA)	2.3												
5	Primary		-	0.029398	-	0.000%	3,881	0.039532	4,034	0.281%	4,034	0.014632	4,093	0.281%
6	Secondary		97,568	0.029398	100,436	7.742%	100,436	0.039532	104,407	7.280%	104,407	0.014632	105,934	7.269%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	480	0.014632	487	0.033%
8	Primary		-	0.029398	-	0.000%	20,274	0.039532	21,076	1.470%	21,076	0.014632	21,384	1.467%
9	Secondary		72,473	0.029398	74,603	5.751%	74,603	0.039532	77,553	5.408%	77,553	0.014632	78,687	5.399%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	1,679	0.014632	1,704	0.117%
11	Primary		-	0.029398	-	0.000%	58,248	0.039532	60,551	4.222%	60,551	0.014632	61,437	4.216%
12	Secondary		28,148	0.029398	28,976	2.234%	28,976	0.039532	30,121	2.100%	30,121	0.014632	30,562	2.097%
13	**STREET LIGHTING**	4.1	7,583	0.029398	7,806	0.602%	7,806	0.039532	8,115	0.566%	8,115	0.014632	8,233	0.565%
14	Total		1,260,176	0.029398	1,297,223	100.00%	1,379,627	0.039532	1,434,166	100.000%	1,436,325	0.014632	1,457,342	100.000%

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, Class NCP Demand.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class NCP Demand increased
- by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers supplied at transmission level as shown in Schedule 4.1. Class NCP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Demand Allocator				Primary Demand Allocator				Transmission Demand Allocator			
			Load at Meter kW	Secondary Demand Loss Factor	Load at Secondary Input kW	Secondary Allocation Factor	Load at Primary Output kW	Primary Demand Loss Factor	Load at Primary Input kW	Primary Allocation Factor	Load at Transmission Output kW	Transmission Demand Loss Factor	Load at Transmission Input kW	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	184,447	0.029398	189,869	15.588%	189,869	0.039532	197,375	14.719%	197,375	0.014632	200,263	14.699%
2	Domestic All Electric	1.1	677,158	0.029398	697,066	57.227%	697,066	0.039532	724,622	54.039%	724,622	0.014632	735,225	53.963%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	17,261	0.029398	17,769	1.459%	17,769	0.039532	18,471	1.378%	18,471	0.014632	18,742	1.376%
4	(10-100 kW)	2.1	130,831	0.029398	134,677	11.057%	134,677	0.039532	140,001	10.441%	140,001	0.014632	142,050	10.426%
	(110-350 kVA)	2.3												
5	Primary		-	0.029398	-	0.000%	3,217	0.039532	3,344	0.249%	3,344	0.014632	3,393	0.249%
6	Secondary		80,879	0.029398	83,256	6.835%	83,256	0.039532	86,548	6.454%	86,548	0.014632	87,814	6.445%
	(350-1000 kVA)	2.3												
7	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	398	0.014632	404	0.030%
8	Primary		-	0.029398	-	0.000%	16,806	0.039532	17,471	1.303%	17,471	0.014632	17,726	1.301%
9	Secondary		60,076	0.029398	61,842	5.077%	61,842	0.039532	64,287	4.794%	64,287	0.014632	65,228	4.788%
	(1000 kVA and Over)	2.4												
10	Transmission		-	0.029398	-	0.000%	-	0.039532	-	0.000%	1,494	0.014632	1,516	0.111%
11	Primary		-	0.029398	-	0.000%	51,829	0.039532	53,877	4.018%	53,877	0.014632	54,666	4.012%
12	Secondary		25,046	0.029398	25,782	2.117%	25,782	0.039532	26,802	1.999%	26,802	0.014632	27,194	1.996%
13	**STREET LIGHTING**	4.1	7,583	0.029398	7,806	0.641%	7,806	0.039532	8,115	0.605%	8,115	0.014632	8,233	0.604%
14	Total		1,183,282	0.029398	1,218,068	100.00%	1,289,920	0.039532	1,340,913	100.000%	1,342,806	0.014632	1,362,454	100.000%

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, Class 1CP Demand.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class 1CP Demand increased
- by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Class 1CP Demand increased
- by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

FUNCTIONAL CLASSIFICATION SPLITS

Scenarios

Line No.	Utility Plant Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Substation Demand E	Distribution Primary Demand F	Distribution Primary Customer G	Distribution Transformers Demand H	Distribution Transformers Customer I	Distribution Secondary Demand J	Distribution Secondary Customer K	Services Customer L	Meters Customer M	St. Lighting Customer N
	PURCHASED POWER														
1	Purchased from Nfld. & Lab. Hydro - Production	100.0%	34.1%	65.9%											
2	Purchased from Nfld. & Lab. Hydro - Transmission	100.0%	100.0%	0.0%											
3	Purchased from Deer Lake Power - Secondary	100.0%	34.1%	65.9%											
	PRODUCTION														
4	Hydro	100.0%	44.9%	55.1%											
5	Other Production	100.0%	100.0%												
	TRANSMISSION														
6	Common	100.0%			100.0%										
	DISTRIBUTION														
7	Substations - Common	100.0%				100.0%									
	Land and Land Use														
8	Primary	100.0%					67.0%	33.0%							
9	Secondary	100.0%									67.0%	33.0%			
10	Street Lighting	100.0%													100.0%
	Conductors, Poles and Fixtures														
11	Primary	100.0%					67.0%	33.0%							
12	Secondary	100.0%									67.0%	33.0%			
13	Street Lighting	100.0%													100.0%
14	Transformers	100.0%							79.0%	21.0%					
15	Services	100.0%											100.0%		
16	Meters	100.0%												100.0%	
17	Street Lights	100.0%													100.0%

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Cost Item	Total	Production	Transmission
18	Purchased from Nfld. & Labrador Hydro	100.0%	92.1%	7.9%

Line No.		Total	Common	Specifically Assigned
19	Transmission	100.0%	99.35%	0.65%

Line No.		Total	Hydro	Other	Total	Transmission	Transmission	Distribution	Distribution	Cust. Acc.
20	Substations	100.0%	4.91%	0.43%	5.34%	26.87%	0.12%	67.49%	0.18%	0.00%

Line No.		Distribution Depreciation, Fixed Assets & CIACs				Distribution Acc. Depreciation			
	Distribution	Total	Primary	Secondary	St. Lighting	Total	Primary	Secondary	St. Lighting
21	Land and Land Use	100.0%	76.19%	19.05%	4.76%	100.0%	75.92%	18.98%	5.10%
22	Conductors, Poles and Fixtures	100.0%	76.19%	19.05%	4.76%	100.0%	75.92%	18.98%	5.10%

Line No.	General Plant Related Costs		Production	Transmission	Distribution	Cust. Acc. Cust. Serv.
23	Gen. Prop. Land and Land Rights	100.0%	5.55%	15.37%	57.30%	21.78%
24	Gen. Prop. Buildings and Structures	100.0%	8.24%	16.42%	57.41%	17.93%
25	Computer Hardware and Software	100.0%	6.41%	10.08%	37.30%	46.21%
26	Gen. Prop. Other Equipment	100.0%	7.34%	17.68%	61.32%	13.65%
27	Transportation	100.0%	3.43%	13.86%	76.18%	6.53%
28	Communication - Total	100.0%	16.93%	32.30%	38.86%	11.91%
29	Communication - Scada	100.0%	19.92%	37.31%	42.77%	0.00%
30	Communication - Total Expenses	100.0%	8.78%	18.31%	50.04%	22.88%
31	Inventory	100.0%	6.73%	24.71%	68.56%	0.00%

FUNCTIONAL CLASSIFICATION SPLITS

Line No.	Utility Plant Category	Reason for Functional Classification
1	Purchased from Nfld. & Lab. Hydro - Production	Classified based on the results, before deficit allocation, of NLH's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
2	Purchased from Nfld. & Lab. Hydro - Transmission	Classified based on the results, before deficit allocation, of NLH's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
3	Purchased from Deer Lake Power - Secondary	Assumed same classification as Nfld. and Lab. Hydro Production related purchased power allocated to NP.
	PRODUCTION	
4	Hydro	Classified based on island interconnected system load factor from of NLH's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
5	Other Production	Classified 100% to Demand
	TRANSMISSION	
6	Common	Classified 100% to Demand
	DISTRIBUTION	
7	Substation - Common	Classified 100% to Demand
	Land and Land Use	
8	Primary	Classified between Demand and Customer Based on a minimum system analysis.
9	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
10	Street Lighting	Classified 100% to direct Street Lighting costs.
	Conductors, Poles and Fixtures	
11	Primary	Classified between Demand and Customer Based on a minimum system analysis.
12	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
13	Street Lighting	Classified 100% to direct Street Lighting costs.
14	Transformers	Classified between Demand and Customer Based on a zero intercept method.
15	Services	Classified 100% to Customer
16	Meters	Classified 100% to Customer
17	Street Lights	Classified 100% to Direct Street Lighting.

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Utility Plant Category	Reason for Functional Classification
18	Purchased from Nfld. & Labrador Hydro	Split between production and transmission related purchased power based on results, before deficit allocation of NLH's proposed 2015 test year COS. See NLH's Amended 2013 GRA, Exhibit 13.
19	Transmission	Based on an analysis of 2012 year end fixed plant. Specifically Assigned based on 2008 Data.
20	Substations	Based on an analysis of 2012 year end fixed plant. Specifically Assigned based on 2008 Data.
	Distribution	
21	Land and Land Use	Split between the different functional groups are based on the split for Conductors Poles and Fittings.
22	Conductors, Poles and Fixtures	Functional split based on a study of fixed assets.
23	Gen. Prop. Land and Land Rights	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
24	Gen. Prop. Buildings and Structures	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
25	Computer Hardware and Software	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
26	Gen. Prop. Other Equipment	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
27	Transportation	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
28	Communication - Total	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
29	Communication - Scada	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
30	Communication - Total Expenses	Based on a 2014 General Property Fixed Plant Allocation Study (2012 Data)
31	Inventory	Based on an allocation of the year end inventory for 2014.

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

RECONCILIATION OF EXPENSES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

The total expenses shown on Schedule 1.1, reflects adjustment of the total reported expenses to *include* depreciation, the amortization of the various Deferrals and *exclude* non-regulated expense, Rural Deficit and certain expenses associated recovered through other revenue (expense credits). Also, Curtailable Service Option credit payments are included as an expense in the Cost of Serivce Study as oppose to a reduction to class revenue from rates as recorded by the Company.

Total Reported Company Expenses	$486,815	(Return 20)
Add		
Depreciation Expense	49,288	(Return 6) (Schedule 1.1)
Curtailable Credits	242	(2014 Curtailable Service Option Report)
Amortization - 2013 General Cost Deferral	1,586	(Schedule 3.2, page 1 of 2 line 31)
Amortization - 2011 and 2012 General Cost Deferrals	1,575	(Schedule 3.2, page 1 of 2 line 32)
Amortization - 2012 Cost of Capital Deferral	829	(Schedule 3.2, page 1 of 2 line 33)
Pro forma Purchased Power Cost Increase	31,937	July 1, 2015 Rate Application dated June 12, 2015.
Less		
Deduct non-regulated expenses[1]	2,801	
Rural Deficit	59,489	(Schedule 1.1, page 2 of 2)
Expense Credits		
Wheeling Revenues	696	(Schedule 1.1)
Joint Use Revenues	2,448	(Schedule 1.1)
Revenue from Temp. Services and Reconnects	87	(Schedule 1.1)
Customer Service Fees	295	(Schedule 1.1)
RSA Transfer - Energy Supply Cost Variance	1,838	(Schedule 1.1)
RSA Transfer - PEVDA and OPEBS	1,724	(Schedule 1.1)
RSA Transfer - Seasonal Rate Revenue Deferral	57	(Schedule 1.1)
RSA Transfer - CDM Revenue Deferral	420	(Schedule 1.1)
Total Expense Credits	7,565	
Rounding	1	
Total expense before Return and Taxes on Schedule 1.1 Excluding RSA, MTA and the Hydro Rural deficit	502,417	

1. Non deductable Expenses (Return 13) + associated tax adjustment - Schedule 5.4

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

RECONCILIATION OF REVENUE WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Revenue from Rates shown on Schedule 1.4 does not include customer billings associated with the RSA and MTA rate adjustments. Also the Curtailable Service Option credit payments are included as an expense in the Cost of Serivce Study as opposed to a reduction to class revenue from rates as recorded by the Company. As a result revenue is increased to remove the impact of the Curtailable Service Option credit payments on revenue.

Revenue from Rates	$619,504	(Return 14)
Add		
Pro forma RSA Billings	(6,227)	(Schedule 1.4)
Pro forma MTA Billings	16,052	(Schedule 1.4)
Curtailable Service Option Credits	242	(2014 Curtailable Service Option Report)
Pro forma Increase in Revenue from Base Rates	31,937	
Rounding	-	
Total Revenue from Final Rates	$661,508	(Schedule 1.4)

Newfoundland Power Inc.
2014 Pro forma Cost of Service Study

RECONCILIATION OF RETURN AND TAXES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Return and Taxes From Annual Report to Board

Return on Rate Base (After adjustment to Regulated Earnings)	$75,601	(Return 13)
Total Income Tax	10,795	(Return 22)
Total Return and Taxes	86,396	
Adjustments		
Tax Adjustment for non-regulated expenses[1].	812	
Tax Adjustment for Cost of Removal[2]	4,594	(Return 6, note 2)
Equity component of AFUDC	659	(Return 13 & 25)
Other Adjustments		
Interest on Tax	-	(Return 25)
Interest on security deposits	19	(Return 25)
Rounding	(1)	
Adjusted Return and Taxes (Schedule 1.1)	92,479	

Notes:

1 - Tax adjustment associated with non-regulated expenses from detail.

Non-regulated expenses	2,801	
Income taxes	812	
Rounding	-	
Non-regulated expenses net of taxes	1,989	Return 12

2 - The income tax is adjusted to reflect cost of removal is recorded net of taxes for regulatory purposes while the tax impact of the cost of removal is recorded as part of Total Income Tax on Return 22.

Customer Rate Impacts

March 2016

Table of Contents

1.0 Introduction

The Company performed impact analysis on the proposed rates relative to the current rates (effective July 1, 2015) for the Domestic class and each of the General Service classes.

This report summarizes the results of this analysis.

2.0 Domestic Methodology

2.1 General

There were approximately 223,000 customer accounts billed on the Domestic rate and approximately 1,900 customer accounts billed on the Domestic-Seasonal Optional rate at December 31, 2014. Evaluation of customer impacts of the proposed rate change for the Domestic class was based upon data from a representative sample of customers served under the Domestic rate.

The Domestic rate has the same energy price year-round. Therefore, the billing impacts can be determined based upon annual usage. The sample design methodology focused on ensuring that the annual usage distribution of the sample is reasonably representative of the annual usage of the population.

The Domestic customers identified in the Customer Service System with electricity as their primary heating source ("Domestic All-Electric") were analyzed separately from the Domestic customers identified as having some other heating source ("Domestic Regular"). The billing impacts were determined by applying the existing and proposed rates to the 2014 monthly electricity usage of a sample of 7,705 customers in the Domestic Regular subgroup and 15,716 in the Domestic All-Electric subgroup.[1]

The Domestic samples were selected using a systematic random sampling method to ensure the samples had comparable annual energy usage distributions to the subgroup populations.

The Domestic-Seasonal Optional Rate has approximately 1,900 participants. The impacts of the proposed customer rates were analyzed based upon the usage data of all customers on the rate option for the full year of 2014.

2.2 Sample Reliability

The Domestic samples provide a 95% confidence with ±1.7% relative accuracy on average monthly energy usage for the Domestic All-Electric subgroup and a 95% confidence with ±0.8% relative accuracy on average monthly energy usage for the Domestic Regular subgroup.

The 2014 average monthly energy usage for the Domestic Regular sample was 933 kWh; this compares to an actual average energy usage of 927 kWh per month for the population.

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1 The samples represent approximately 10% of the total customers in the respective subgroups.

The 2014 average monthly energy usage for the Domestic All-Electric sample was 1,661 kWh; this compares to an actual average monthly energy usage of 1,604 kWh for the population. The higher sample average energy use can be attributed to excluding customer accounts that were not active for all 12 months of 2014 in the sample selection process.[2]

The Domestic samples are reasonable for the purpose of evaluating the effects of the proposed rate changes on customer accounts.

3.0 General Service Methodology

There were 23,324 General Service customer accounts billed at year-end 2014.

Table 1 provides the breakdown of customer accounts, sales and revenue by rate class.

Table 1
General Service Classes

Rate	Rate Class	Customer Accounts	Sales (GWh)	Revenue ($000s)
2.1	0-100 kW (110 kVA)	22,013	782.8	82,080
2.3	110-1000 kVA	1,241	965.1	88,789
2.4	1000 kVA and Over	70	505.6	39,743
	Total General Service	**23,324**	**2,253.5**	**210,612**

The Company reviewed the billing impacts for all customer accounts that were on each rate for the full year of 2014.

[2] The population average use includes new connections during the year. Because two of the coldest winter months occur early in the year (i.e., January and February), the monthly average use for the population would not have included the coldest months for most new accounts. As a result, the average use would be expected to be lower for the population than the monthly average use for the sample because the sample only included customer accounts that were active for all 12 months in 2014. As temperature has less of an effect on average use for Domestic Regular customers, new customer connections would not have created a material difference on the average use between the sample and the population for that subgroup.

4.0 Customer Impacts

4.1 Domestic

Table 1 shows the customer bill impacts for Domestic rate customers under the proposed rate.

Table 1
Domestic 1.1
Customer Bill Impacts

Annual Impact (%)	% of Customers
Less than 3.1%	0.1
3.1%	99.3
More than 3.1%	0.6
% Receiving Increases	100.0

The proposed 3.1% increase in the Domestic rate has been applied equally to each rate component. For this reason, over 99% of all customers will receive annual bill impacts of 3.1%.

Customers not receiving a 3.1% increase are customers that (i) are charged the Basic Customer Charge Exceeding 200 Amp Service with low usage or (ii) are charged on the Domestic Seasonal rate. The minimum customer increase is 2.5%. The maximum customer increase is 3.5%.

The Basic Customer Charge Exceeding 200 Amp Service was designed to maintain a $5 charge above the Basic Customer Charge Not Exceeding 200 Amp Service.

The Domestic Seasonal rate was designed to maintain the existing energy charge adjustments as shown in Rate #1.1S.[3]

[3] See Schedule A to the Application, Rate #1.1S, page 2 of 8.

4.2 General Service

Table 2 shows the customer bill impacts for the Rate 2.1 under the proposed rate.

Table 2
Rate 2.1
Customer Bill Impacts

Annual Impact (%)	% of Customers
More than -10	1.4
-10 to -8	0.1
-8 to -6	1.6
-6 to -4	3.5
-4 to -2	4.4
-2 to 0	12.7
% Receiving Decreases	23.8
0 to 2	25.3
2 to 4	40.7
4 to 6	7.1
6 to 8	1.7
8 to 10	0.8
More than 10	0.6
% Receiving Increases	76.2

The range of decreases and increases primarily results from the Company's proposal to set the Rate 2.1 Basic Customer Charge (i) for unmetered service, at $4.00 less than the single phase service charge and (ii) for three phase service, at $6.00 greater than the single phase service charge. The overall increase of 2.5% has been applied equally to each other rate component to the extent possible.

Customers receiving a rate decrease of more than 6% are unmetered customers and three phase customers subject to the minimum monthly charge. Customers receiving a rate increase of more than 6% are three phase customers with low usage. The maximum bill increase experienced by any of these customers is less than $10.00 per month.

Table 3 shows the customer bill impacts for the Rate 2.3 under the proposed rate.

Table 3
Rate 2.3
Customer Bill Impacts

Annual Impact (%)	**% of Customers**
0 to 1	98.0
1 to 2	0.9
2 to 3	1.1
% Receiving Increases	100.0

< > The proposed rate provides no change, on average, in customer rates. The maximum monthly charge has been increased by 2.5% for all General Service customers.

Table 4 shows the customer bill impacts for the Rate 2.4 under the proposed rate.

Table 4
Rate 2.4
Customer Bill Impacts

Annual Impact (%)	**% of Customers**
2.4%	6.2
2.5%	86.1
2.6%	7.7
% Receiving Increases	100.0

The proposed rate provides a 2.5% average increase in customer rates. The increase has been applied equally to each rate component to the extent possible.

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**Elimination of Unwarranted Three Phase Charge:
Required Regulation & Policy Changes**

October 2015

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 General

Historically, Newfoundland Power Inc. ("Newfoundland Power" or the "Company") charged General Service customers an Unwarranted Three Phase Charge for the additional cost to provide three phase service which was not forecast to be collected through customer rates. Unwarranted Three Phase Charges are typically charged to, and paid by, General Service customers served under Rate 2.1

In this Application, the Company proposes the implementation of different Basic Customer Charges for General Service customers served under Rate 2.1. These different charges require a higher Basic Customer Charge for customers with three phase service. The higher monthly Basic Customer Charge for three phase service will recover the additional cost associated with providing three phase service.

If the proposed implementation of the changes to the Basic Customer Charge for Rate 2.1 is approved by this Board, the Unwarranted Three Phase Charge will no longer be necessary. So, the Company is proposing the elimination of the Unwarranted Three Phase Charge for General Service customers.[1]

To appropriately eliminate the Unwarranted Three Phase Charge for General Service customers, Newfoundland Power is proposing 3 modifications to existing regulatory policies. Firstly, it is proposed that Section of 5 (b) of the Company's Rates, Rules and Regulations be modified to reflect the elimination of the charge to General Service customers. Secondly, it is proposed that modifications be made to the Company's *Contribution in Aid of Construction Policy: Distribution Line Extensions and Upgrades To General Service Customers* ("the G.S. CIAC Policy") to reflect elimination of the charge.[2] Thirdly, it is proposed that a transition provision be made for customers that have paid an Unwarranted Three Phase Charge over the past 20 years.[3]

1 See *Section 6.4.2: Rate Structure Changes* at page 6-9 for more detail on the justification for implementation of different Basic Customer Charges for Rate 2.1 customers with unmetered, single phase and three phase service.

2 The G.S. CIAC Policy also currently provides for an Unwarranted Three Phase Charge. In the future, the higher monthly Basic Customer Charge for three phase service will recover the additional cost associated with providing three phase service to all General Service customers. Accordingly, continuation of an Unwarranted Three Phase Charge in the Company's G.S. CIAC Policy would result in customers paying both a higher Basic Customer Charge for three phase service *and* an Unwarranted Three Phase Charge. This, in effect, would result in the customer paying twice for the additional cost (relative to single phase service) of the three phase service provided.

3 Customers that have already paid an Unwarranted Three Phase Charge have, in effect, fully paid for the extra cost of three phase service over single phase service. For these customers, charging a higher Basic Customer Charge for three phase service would result in the customer paying twice for the additional cost (relative to single phase service) of the three phase service provided.

2.0 Proposed Changes to Regulation 5(b)

It is proposed that Clause 5(b) be modified to eliminate the need for an Unwarranted Three Phase Charge for General Service customers and to allow the Company to charge a Domestic customer the additional cost of three phase service as a special service under Regulation 9(c).[4]

The proposed wording for Regulation 5(b) is:

> *5(b) Service to customers who are provided Domestic Service shall be supplied at single phase 120/240 volts or as part of a multiunit building, at single phase 120/208 volts. The Company may, if requested by the customer, provide three phase service if a contribution in aid of construction is paid to the Company in accordance with Regulation 9(c).*

3.0 Proposed Changes to the G.S. CIAC Policy

The G.S. CIAC Policy was most recently approved by Order No. P.U. 27 (2005). The cost Appendices to the policy were most recently approved by Order No. P.U. 9 (2015). The G.S. CIAC Policy provides for unwarranted three phase charges to customers with estimated maximum Demand of under 75 kW.[5]

Modification of the G.S. CIAC Policy is required to (i) Section 3. Basic Investment, (ii) Section 5. Calculation of CIACs, and (iii) Appendix C.

The proposed changes to the G.S. CIAC Policy are shown in Schedule A to this report. Proposed additions to the G.S. CIAC Policy are shaded , deletions are ~~struck through~~.

4.0 Transitional Provisions

Since 1997, there have been approximately 250 customers who have paid a CIAC for an Unwarranted Three Phase Charge in accordance with Newfoundland Power's existing Rules and Regulations.[6] These customers are currently served under Rate 2.1. To ensure the elimination of the Unwarranted Three Phase Charge does not unduly penalize these customers, the Company proposes to allow these customers to pay the single phase basic customer charge as long as they continue to be supplied at the serviced premise for which an Unwarranted Three Phase Charge was paid.[7]

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[4] The Company currently supplies approximately 100 Domestic customers who required a three phase service.

[5] See Section 5(a)(i) of the *Contribution in Aid of Construction Policy: Distribution Line Extensions and Upgrades To General Service Customers* approved by Order No. P.U. 27 (2005).

[6] Any CIAC for an Unwarranted Three Phase Service since 2013 is subject to a 24 month review. It is uncertain at this time the actual count of customers from 2013 and 2014 that will be subject to an Unwarranted Three Phase Charge until the 24 month review is complete.

[7] Customers with an existing CIAC subject to a 24 month review after the proposed change becomes effective will receive a refund of any portion of their CIAC that is related to unwarranted three phase service.

NEWFOUNDLAND POWER INC.

CONTRIBUTION IN AID OF CONSTRUCTION POLICY:

DISTRIBUTION LINE EXTENSIONS AND UPGRADES

TO GENERAL SERVICE CUSTOMERS

1. THE POLICY: GENERAL

The Company will provide Line extensions or Upgrades for Permanent Service to General Service Customers without a CIAC when the cost to provide and maintain the Line extension or Upgrade will be recovered through electricity rates paid by those customers. Otherwise, a CIAC calculated in accordance with this policy will be required.

2. INTERPRETATION

Board means the Board of Commissioners of Public Utilities for Newfoundland and Labrador.

CIAC means a contribution in aid of construction.

Clearing Costs means the estimated costs for the required brush clearing along the route of a Line extension or Upgrade.

Company means Newfoundland Power Inc.

Cost per Metre means the average construction and maintenance cost per metre of Line extension or Upgrade as calculated by the Company and filed from time to time with the Board. For Upgrades, this includes only the costs associated with the primary conductor and related hardware. See Appendix A.

Demand means the quantity of electricity which is delivered to a customer. It is expressed in kilowatts or kilovoltamperes, either at a given point in time or averaged over a period of time.

Domestic Policy means the Company's policy entitled "Contribution in Aid of Construction Policy: Distribution Line Extensions to Domestic Customers" as approved by the Board.

Easement Costs means the estimated costs to complete a survey of the right-of-way for a Line extension or Upgrade, and includes the labour costs to complete the survey, survey document and drawing; travel costs; and registration fees.

General Service Customer means a customer eligible for Permanent Service or Temporary Service pursuant to any of Rate #'s 2.1, 2.2, 2.3 or 2.4 of the Company's Schedule of Rates, Rules & Regulations.

Line means an electrical distribution line and includes a Main Line or a Service Line.

Load Factor means the ratio of the average Demand in kilowatts supplied during a designated period to the maximum Demand in kilowatts supplied in that period. The average Demand is determined by dividing the energy consumption in kilowatt hours by 730 hours (if monthly) or by 8760 hours (if yearly).

Main Line means any Line required to supply electricity that is not a Service Line.

Municipality is as defined in the *Municipalities Act, 1999.*

Peak Demand means the maximum annual Demand that will be required by a customer.

Permanent Service means electrical service required for at least three years.

Schedule of Rates, Rules & Regulations means the schedule setting out the rates, rules and regulations relating to the Company's service as approved from time to time by the Board.

Service Drop means the span of Service Line from a customer's service entrance to the first pole that is connected to the Company's electrical system.

Service Line means any Line across private property or along a private road required to serve a single customer.

Temporary Service means a service that is required for a period of less than three years.

Upgrade means the upgrade of either (i) single phase Line to two phase, or (ii) single or two phase Line to three phase.

3. BASIC INVESTMENT

The Company's Basic Investment in a Line extension for Permanent Service to General Service Customers shall include:

(i) Up to 85 metres of Line[1], as measured from the point where the customer takes service, and all plant directly associated with that specific length of Line;

(ii) transformation for service up to 500 kVA where the required service voltage is one of the Company's standard service voltages and installation is in accordance with Company standards,[2]

(iii) secondary metering; and,

(iv) where the service location is on the side of the road opposite the Company's Line, the number of metres of Service Line equal to the width of the road right-of-way.

[1] The Line will be single phase or three phase depending on the requirements of the customer. ~~the line will be either three pase or single phase. Single phase, where the maximum Demand is estimated to be less than 75 kW. Otherwise, three phase. The Company may provide three phase service where maximum Demand is less than 75 kW, if requested by the customer, to the extent that such service is supported by projected revenue from the customer as set out in Regulation 5(b) of the Schedule of Rates, Rules & Regulations.~~

[2] The Company may, on such conditions as it deems acceptable, provide transformation for services greater than 500 kVA as set out in Regulation 5(j) of the Schedule of Rates, Rules & Regulations.

4. ADDITIONAL INVESTMENT

(a) Additional Growth Based Investment

In addition to its Basic Investment, the Company will provide Additional Growth Based Investment in the form of single phase Main Line extensions for Permanent Service to General Service Customers. Additional Growth Based Investment will be provided if there is satisfactory evidence that future growth along the route of the Main Line extension will be sufficient to support the cost to construct and maintain the Main Line extension. The existence of a foundation for a new building along the route of the Main Line extension shall constitute satisfactory evidence of sufficient future growth.

For each such foundation, the Company will provide the number of metres of single phase Main Line, and all plant directly associated with that specific length of Main Line, that would be provided as Basic Investment under this policy or the Domestic Policy to a customer requiring service at the location of the foundation.

(b) Additional Load Based Investment

In addition to its Basic Investment and Additional Growth Based Investment, the Company will provide Additional Load Based Investment for Permanent Service to General Service Customers with a Demand exceeding 10 kW. Additional Load Based Investment will be provided to the extent that it will be recovered from revenue generated by the customer(s) requesting the Line extension or Upgrade. The amount of Additional Load Based Investment that will be supported by such revenue shall be determined by reference to the anticipated Load Factor and Peak Demand of the customer(s) in accordance with the Plant Support Table in Appendix B.

5. CALCULATION OF CIACs

(a) The cost of a Line extension or Upgrade for a General Service Customer shall, as applicable, be composed of the following:

~~(i) for a three phase Line extension or Upgrade to a customer with an estimated maximum Demand of under 75 kW, construction cost that is equal to the sum of (1) the number of metres of Line extension or Upgrade beyond the Service Drop multiplied by the applicable Cost per Metre as set out in Appendix A, and (2) the cost of the Service Drop, transformation and metering, based on the costs set out in Appendix C;~~

(i)~~(ii)~~ for all Line extensions or Upgrades, construction cost that is equal to the product of (1) the total number of metres of Line extension or Upgrade, and (2) the applicable Cost per Metre as set out in Appendix A;

(ii)~~(iii)~~ applicable Clearing Costs and Easement Costs;

(iii)~~(iv)~~ for an Upgrade, the costs associated with the replacement, transfer or installation of additional poles or anchors, including, without limitation, the costs set out in Appendix C.

(b) The CIAC for Line extensions or Upgrades for General Service Customers shall, subject to Clause 5 (c), be equal to the cost of the Line extension or Upgrade, as determined in accordance with Clause 5 (a), less the value of the Company's Basic and Additional Investment as provided for in Clauses 3 and 4.

(c) In cases where the Line extension or Upgrade will be shared by more than one customer, any CIAC required will be apportioned based on the length of the Line extension or Upgrade required to serve each customer. Where a customer is connected to a Line extension or Upgrade in respect of which a CIAC was paid within ten years from the date that the Line extension or Upgrade was placed in service, that customer shall pay a CIAC calculated as if service was connected to that customer when the Line extension or Upgrade was originally placed in service.

(d) For Upgrades, Clause 5 (c) does not apply to customers that require single phase service and are connected to a Line for which a CIAC was paid solely for an Upgrade.

(e) Detailed cost estimates will be used in place of the applicable Cost per Metre in determining the cost of a Line extension or Upgrade when either: (i) the cost of a Line extension or Upgrade calculated using the applicable Cost per Metre is estimated to be greater than $100,000, or (ii) an Upgrade is required from single phase to two phase Line.

(f) The Company's Additional Load Based Investment for a Permanent Service will be reduced by 2.5% for each year that the estimated life of the customer's operations is less than the depreciable life of the distribution plant used in the Line extension or Upgrade.

6. REFUNDS

(a) Subject to Clause 5 (d), where additional customers are connected to a Line extension or Upgrade within 10 years from the date that the Line extension or Upgrade was placed in service, the Company will refund all or part of a CIAC previously paid in respect of that Line extension or Upgrade by the existing customers. The amount of the refund to each existing customer will be the amount by which (i) the CIAC paid by that existing customer less any refunds already received thereon, exceeds (ii) the CIAC which would have been payable by that existing customer under Clause 5 if the additional customers had taken service at the time the Line extension or Upgrade was originally placed in service. A refund becomes due 90 days following the connection of the additional customer(s).

(b) Interest paid through the financing option outlined in Clause 8 is not refundable.

(c) The Company shall advise customers of its CIAC refund policy. The Company shall make all reasonable efforts to identify customer refunds. A refund that is past due will accrue interest at the rate prescribed in Clause 8 (b) commencing on the day following the day it became due.

7. SERVICE ENTRANCE LOCATIONS

Should a General Service Customer request the Company to attach to a service entrance that is not as close as practical to the distribution pole from which the Service Line is to be run, the customer will be required to pay the costs associated with any additional plant.

8. PAYMENT

(a) All CIACs shall be paid in advance of construction, except in the following cases:

(i) Federal or Provincial Government Departments may provide a purchase order;

(ii) General Service Customers, if approval has been given in advance by the Company's credit personnel, may provide a purchase order; and,

(iii) where approval has been given in advance by the Company's credit personnel, a customer may pay a CIAC on the following basis:

(1) $300 or ¼ of the CIAC, whichever is greater, as a down-payment in advance of construction; and,
(2) the balance together with interest by way of not more than 60 equal monthly installments of not less than $20 each.

(b) The interest rate applied to an unpaid CIAC balance shall be set at the time of the issuance of the customer’s CIAC quote. The rate shall be equal to the prime rate of the Company’s bankers as of the last day of the month immediately preceding the issuance of the CIAC quote to the customer, plus 3%.

(c) CIAC Installments shall be subject to the Company's credit policy. Default in payment of any installment on a CIAC shall, at the Company's option, render the unpaid balance immediately due and payable.

(d) Should a customer wish to prepay all or a portion of the unpaid balance, the Company will accept such pre-payment without bonus or penalty.

9. REVIEW OF CIACs

All CIACs collected from General Service Customers will be subject to a review after a period of 24 months from the date the service is made available. The purpose of the review is to determine the reasonableness of the original CIAC calculation. If the recalculated CIAC differs from that originally calculated by more than $100, such difference will, as applicable, be charged or refunded to the customer's electric service account.

10. BOARD APPROVALS

The Company shall apply to the Board for approval of:

(i) all Line extensions or Upgrades involving CIACs where the costs of the Line extension or Upgrade calculated pursuant to Clause 5 (a) are estimated to be greater than $50,000; and,

(ii) any deviations from this policy in the calculation of CIACs for Line extensions and Upgrades to General Service Customers.

NEWFOUNDLAND POWER INC.

DISTRIBUTION LINE COST PER METRE
FOR GENERAL SERVICE CIACs
Effective March 25, 2015

TYPE OF CONSTRUCTION	**COST / METRE** [1] $
LINE EXTENSIONS	
SINGLE PHASE	**34**
THREE PHASE	**49**
UPGRADES [2]	
SINGLE PHASE TO THREE PHASE	**44**
TWO PHASE TO THREE PHASE	**26**

[1] These cost factors do not include any costs for clearing or obtaining easements. When clearing is required, an additional charge of $4.00 per metre will apply to the section of line beyond the distance of the Basic Investment. A $350 charge will be applied for each required easement beyond the distance of the Basic Investment.

[2] These costs include only the cost associated with primary conductors and related hardware in upgrades. For additional costs refer to Appendix C: Distribution Plant Upgrade Cost for General Service CIACs.

NEWFOUNDLAND POWER INC.
DISTRIBUTION PLANT SUPPORT TABLE
FOR GENERAL SERVICE CIACs
Effective March 25, 2015

Annual Load Factor	Dollars per kW/kVA [1]
Less than 5%	**92**
5%-9.9%	**133**
10%-14.9%	**146**
15%-19.9%	**166**
20%-24.9%	**179**
25%-29.9%	**187**
30%-34.9%	**198**
35%-39.9%	**211**
40%-44.9%	**222**
45%-49.9%	**231**
50%-54.9%	**238**
55%-59.9%	**245**
60%-64.9%	**256**
65%-69.9%	**261**
70% and Over	**266**

[1] The Additional Load based Investment, which applies to customers with a maximum annual demand exceeding 10 kW, will be determined by multiplying (i) the estimated maximum annual demand, less 10 kW, and (ii) the appropriate dollars per kW/kVA.

NEWFOUNDLAND POWER INC.
DISTRIBUTION PLANT UPGRADE COST
FOR GENERAL SERVICE CIACs
Effective March 25, 2015

TYPE OF TRANSFER OR REPLACEMENT		COST [1] ($)
REPLACE POLES - UP TO 45'		2,180
ADDITIONAL POLES		1,290
DISTRIBUTION SECONDARY PER POLE / SPAN		
Transfer Only		770
Replace Conductor		940
SERVICE DROP PER POLE / SPAN		
Transfer Only		80
Replace Conductor		140
TRANSFORMER MOUNTINGS		
Single Transformer		920
Two or Three Transformers		2,250
POLE GUY		
Transfer Only		40
Replace Guy		70
REPLACE ANCHOR		560
ADDITIONAL ANCHOR		300
STREETLIGHTING - TRANSFER SINGLE FIXTURE		230
STREETLIGHTING DUPLEX PER POLE / SPAN		
Transfer Only		80
Replace Conductor		130
~~UNWARRANTED THREE PHASE CONSTRUCTION COST~~	-	-
~~(SERVICE DROP, METER & TRANSFORMER)~~	-	-
~~New Service~~	-	~~8,400~~
~~Upgrade Single Phase to Three Phase~~	-	~~4,800~~
~~Upgrade Two Phase to Three Phase~~	-	~~2,100~~
-	-	-
~~VALUE OF SINGLE PHASE BASIC INVESTMENT~~	-	~~6,000~~

[1] Includes all overheads.

Curtailable Service Option Review

October 2015

Table of Contents

1.0 Executive Summary

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") reviewed its Curtailable Service Option (the "Option") in 2014.

The purpose of the review was to assess the effectiveness of the Option and identify changes that might improve the attractiveness of the Option to the Company's customers. A significant impetus for the review were the supply issues and power outages encountered on the Island Interconnected system in January 2014.[1]

The review included:

(i) a scan of similar curtailable, or interruptible, programs offered in other Canadian jurisdictions; and
(ii) consultations with current Option customers to determine what changes could improve the Option.

As a result of Newfoundland Power's review, changes modifying penalty provisions and broadening Option eligibility are proposed. The proposed changes are designed to promote continued reliable curtailment capability for the Island Interconnected system. The proposed changes are also reasonably consistent with current Canadian regulatory practice.

2.0 Newfoundland Power's Curtailable Service Option

The Option is available to customers served under General Service Rates 2.3 and 2.4 that have a billing demand of at least 300 kW. Every Option customer must agree to curtail its demand by between 300 kW and 5,000 kW.[2]

The Option provides an annual credit (a "curtailment credit") to customers for reducing their electrical demand at the request of Newfoundland Power during the winter peak season.[3]

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[1] Following the supply shortage and power outages event in January 2014, it was evident that increasing the amount of contracted load curtailment would benefit the Island Interconnected system. For example, the Board's consultant in its investigation into the January 2014 supply shortage and power outage event, The Liberty Consulting Group, in their *Interim Report* of April 24, 2014 stated on page 37: "Additional interruptible load, further load reductions via curtailment arrangements, and added conservation efforts are all avenues that should be pursued. We would not expect, however, that any of these individual measures will make a very large contribution, although collectively the effects will be welcome. When a borderline situation exists, every saved MW can be of real value; hence, such efforts should be encouraged. We observe that the effects may prove small compared to those of new generation."

[2] This translates to between 330 kVA and 5,500 kVA.

[3] The winter peak season is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a customer to curtail must be demonstrated to the Company's satisfaction prior to the customer's availing of this rate option.

Sixteen general service customers participated in the Option during the 2014-2015 winter season, providing average curtailed load of approximately 10.4 MW. Over the past 5 winter seasons, Option customers have successfully curtailed load 92% of the times they were requested to do so by Newfoundland Power.[4]

Appendix A shows the Company's current Curtailable Service Option.

3.0 Customer Consultation

In June 2014, Newfoundland Power consulted current Option customers to solicit feedback on the Option.[5]

A primary customer concern related to the number of curtailment requests in the 2013-2014 winter season. This has largely been addressed by Order No. P.U. 47 (2014). This Order effectively restricts the Company's requests to curtail to circumstances where there is a capacity constraint on the Island Interconnected system. The practical effect of the Order is to reduce the number of Newfoundland Power requests for customers to curtail so the Company can manage its power supply costs.

The other suggestions received from customers related to: (i) relaxing penalty provisions of the Option, (ii) permitting grouped curtailment and (iii) increasing the value of the credit.

4.0 Comparable Canadian Service Offerings

Four Canadian electric utilities other than Newfoundland Power have curtailable service offerings at a distribution level. They are Nova Scotia Power, Hydro Quebec, Manitoba Hydro and SaskPower.[6]

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4 Detailed results for the 2014-2015 winter peak season were submitted to the Board in the Company's 2015 Curtailable Service Option Report dated April 30, 2015.

5 This consultation supplemented the Company's routine practice of contacting all Option participants prior to the winter season to confirm participation and verify curtailment compliance processes. The consultation included 13 of the 17 Option customers during the 2013-2014 winter season and a former Option customer that chose not to participate during the 2013-2014 winter season.

6 No comparable rate options existed at the distribution service level in Prince Edward Island, New Brunswick, Ontario, Alberta and British Columbia.

Table 1 summarizes key features of comparable curtailable service offerings of Canadian electrical utilities.

Table 1
Canadian Electric Distribution Utilities
Curtailable Service Offerings
Key Features
(kW or kVA)[7]

	Newfoundland Power	**Nova Scotia Power**	**Hydro Quebec[8]**	**Manitoba Hydro[9]**	**Sask Power[10]**
Minimum Demand Eligibility[11]	300	2,000	1,000	5,000	5,000
Minimum Curtailment	300	2,000	200	5,000	5,000
Annual fixed credit ($)	29.00/kVA	41.16/kVA	13.00/kW	28.22/kW	20.00/kW
Variable credit ($/kWh)	-	0.004[12]	0.20 - 0.30[13]	-	0.15[14]
Notification Period	1 hour	10 minutes	2 hours	5 minutes	2 hours
Eligibility Termination	3 failures	-[15]	4 failures	3 failures	-[16]

Newfoundland Power's Option has the lowest minimum demand eligibility for participation. The Company's Option has the 2nd lowest minimum curtailment requirement. These features are

7 All amounts are in kW except Nova Scotia Power, which are shown in kVA. Although different units, the amounts are comparable as the difference between a kW and a kVA is not material.
8 Option I under the interruptible electricity options for medium-power customers is shown. Hydro Quebec provides several interruptible rates for different classes of customers. The option shown represents the most comparable option to Newfoundland Power. This option is the option used throughout this review.
9 Option A interruptible rate option is shown. Manitoba Hydro provides several interruptible rate options. The option shown represents the most comparable option to Newfoundland Power. This option is the option used throughout this review.
10 Program Offer 2 is shown. SaskPower provides 2 interruptible rate options. The option shown represents the most comparable option to Newfoundland Power. This option is the option used throughout this review.
11 Eligibility to participate in a curtailable rate option can be based upon a customer's maximum demand. Practically, a customer with a higher maximum demand will tend to have a higher ability to curtail, whether by using back-up generation or by reducing its operational load.
12 Nova Scotia Power provides a separate energy charge, which is applied to all kWhs, for its interruptible customers as part of its Large Industrial Tariff (2,000 kVA and over). The energy charge for interruptible customers is $0.004/kwh less than the energy charge for firm customers.
13 The variable credit is based on the duration of the curtailment.
14 The variable credit is based on the kWh reduction during curtailment.
15 Nova Scotia Power requires 5 year notice if a customer decides not to be served under the interruptible rate option.
16 SaskPower does not specify the number of customer curtailment failures which will lead to termination of participation.

a reflection of the Company's customer base.[17]

Newfoundland Power has the 2nd highest fixed curtailment credit amongst comparable service offerings. Newfoundland Power's Option does not include a variable credit.

The 1 hour notification period for Newfoundland Power's Option is within the 5 minute to 2 hour range for comparable Canadian curtailable service options.

5.0 Newfoundland Power Proposals

5.1 Penalty Provisions

Of the 13 Newfoundland Power customers consulted on the Option, 8 suggested changes to the penalty clause.[18] Generally, the penalty clause was seen by customers to be too punitive.

Currently, an Option customer's curtailment credit is reduced by 50% as a result of the first failure to curtail. Each additional failure to curtail results in a further 25% reduction in the curtailment credit. After 3 failures, the customer is no longer entitled to a credit or service under the Option.[19]

Newfoundland Power proposes to implement a two tiered approach for failing to curtail. This approach incorporates suggestions from customers received during the consultation phase. The proposed changes to the Failure to Curtail clause of Option are:

1. The maximum number of failures to curtail in a winter period will be increased from 3 to 4.
2. Tier 1 will include the first 5 curtailment requests in the winter period. For each failure to curtail in Tier 1 the Curtailment Credit will be reduced by 25%.
3. After the 5th curtailment 50% of the remaining Curtailment Credit, if any, will become vested.

[17] Less than 0.01% of Newfoundland Power's customers are served under Rate 2.4 (1,000 kVA and over). Thirteen of the current 16 Option customers are served under Rate 2.3 (110-1,000 kVA).

[18] Seven of these customers are represented by a single entity.

[19] See Appendix A for Newfoundland Power's current Curtailable Service Option rate. The "Failure to Curtail" clause is the penalty clause.

4. Tier 2 will include all remaining curtailment requests in the winter period. For each failure to curtail in Tier 2 the Curtailment Credit will be reduced by 12.5%.[20]

In the past 2 winter seasons, there were 9 Option requests as a result of supply shortage events.[21] There remains a high risk of supply shortage events until the Island Interconnected system is interconnected to the North American grid.[22] A higher number of allowed failures increases the probability of load curtailment being available in winter periods that involve frequent, or extended, supply shortage events.

5.2 Grouped Curtailment

In customer consultations on the Option, it was indicated that Newfoundland Power should consider allowing smaller facilities owned by the same person to aggregate their load curtailment. This would allow the facilities to collectively meet the 300 kW minimum demand eligibility and curtailment requirements. For example, an owner of 3 facilities, each able to curtail 100 kW, should be eligible to participate in the Option.

Newfoundland Power proposes to allow grouped curtailment to achieve the minimum eligibility requirement of 300 kW upon certain conditions. Each facility would be required to curtail a minimum of 100 kW.[23] The group would be treated as one customer for curtailment purposes

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[20] For example, if a customer is eligible to receive a $100,000 curtailment credit and failed twice in the first 5 requests, a $50,000 credit reduction would occur ($100,000 curtailment credit x 25% x 2). The curtailment credit achieved to that date would be $50,000 ($100,000 curtailment credit less the $50,000 credit reduction). Half of this amount, or $25,000, would be considered vested after the 5th curtailment request. Beginning with the 6th request, the customer would remain subject to the penalty clause. If another curtailment failure occurs, it will result in a further $12,500 credit reduction ($100,000 curtailment credit x 12.5%). The customer's credit for the winter period would then be $37,500 ($50,000 curtailment credit achieved after the 5th request less the $12,500 credit reduction). If the customer then fails to curtail a 4th time, then (i) the customer's credit would be limited to the amount vested after the 5th Curtailment request, or $25,000 and (ii) the customer would no longer be able to participate in the Option.

[21] In 2013-2014, there were 7 Option requests as a result of a supply shortage event. In 2014-2015, there were 2 such Option requests.

[22] The Board's consultant in its investigation into the January 2014 supply shortage and power outage event, The Liberty Consulting Group, in their Interim Report of April 24, 2014 found the outages "…..stemmed from two differing sets of causes: (a) the insufficiency of generating resources to meet customer demands, and (b) issues with the operation of key transmission system equipment" and further that "…..a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons." These findings were essentially confirmed in The Liberty Consulting Group's Final Report addressing Newfoundland and Labrador Hydro of December 17, 2014.

[23] This is practical in terms of (i) quantifying the amount of curtailment achieved and (ii) the cost of providing metering to a group. For quantification of results, larger load curtailments tend to be easier to observe and quantify whereas smaller load curtailments may not be as easily observed due to the load characteristics of the customer. For metering costs, it costs approximately $2,500 to install a load recorder meter. There is also an annual cost of $250 per meter for telephone service to able to access the recordings. The current maximum cost to connect a customer that can curtail 300 kW is approximately $9/kW [($2,500 + $250) / 300 kW]. With the proposed grouped curtailment, that maximum cost would be $27/kW, triple the current amount and approximately the amount of the annual curtailment credit.

and a single point of customer contact would be required.[24] The credit would be distributed to the group participants based upon a pre-determined allocation.[25]

5.3 Value of the Credit

In customer consultations on the Option, it was suggested that the value of the curtailable credit be increased.

Interruptible or curtailable credits are typically valued at the estimated marginal cost of capacity.[26]

Current interruptible rates negotiated by Hydro and 2 of its industrial customers indicate a rate of \$28/kW.[27] Newfoundland Power's current Option credit at \$29/kVA is comparable to this amount.

The amount of Newfoundland Power's current curtailment credit appears reasonably consistent with other Canadian jurisdictions.[28]

The marginal cost of capacity for the Island Interconnected system is currently unclear.[29] Up to the time of interconnection to the Northern American grid, the Option provides value to the Island Interconnected system.[30] But the value of the Option after interconnection is uncertain. In light of this uncertainly, it does not appear appropriate to change the value of the Option at this time.[31]

Given these circumstances, Newfoundland Power is not proposing any change to the current \$/kVA curtailment credit.

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[24] For example, if, as a group, one failure occurs because one participant does not curtail, the failure will result in a 25% penalty for the entire group.

[25] The pre-determined allocation would be required to be agreed on by the group participants and the Company before the start of the winter peak season.

[26] For example, Manitoba Hydro's curtailable service option referenced discount is related to the marginal value of capacity.

[27] See the responses to Requests for Information PUB-NLH-461 and NP-IC-022 filed as part of Hydro's Amended 2013 General Rate Application.

[28] See Table 1, page 3.

[29] See *Section 6.3.2: Marginal Cost Outlook*, page 6-8, footnote 14.

[30] See footnote 1.

[31] This is consistent with sound public utility practice. For example, the Manitoba Public Utilities Board has recently found that any expansion to Manitoba Hydro's Curtailable Rate Program ("CRP") would be premature given the construction of the 695 MW Keeyask Generating Station in Northern Manitoba. Page 88 of Order No. 73/15 (July 24, 2015), issued by the Manitoba Public Utilities Board, states: "The Board accepts Manitoba Hydro's explanation that, at the present time, the value of the CRP is diminished and notes that new long term capacity resources in Manitoba, once Keeyask is constructed, will not be required until 2033/34. As such, while the Board believes that there may be merit in MIPUG's suggestion that an expanded CRP with long term contracts could provide capacity benefits, it is premature at this time to expand the program. The Board therefore approves the finalization of Manitoba Hydro's proposed changes to the CRP, including the proposed cap."

5.4 Proposed Curtailable Service Option

Appendix B shows the Company's proposed Curtailable Service Option. Additions necessary to give effect to Newfoundland Power's proposals are indicated by shading.

NEWFOUNDLAND POWER INC.
CURRENT CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{(\text{Maximum Demand during Peak Period x 1573 hours})}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:

1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURRENT CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced by 50% as a result of the first failure to Curtail during a Winter. For each additional failure to Curtail, the Curtailment Credit will be reduced by a further 25% of the Curtailment Credit. If the Customer fails to Curtail three times during a Winter, the Customer forfeits 100% of the Curtailment Credit and the Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

NEWFOUNDLAND POWER INC.
PROPOSED CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4, that can reduce their demand ("Curtail"), whether individually or in aggregate, by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Customers that reduce their demand in aggregate will be treated as a single Customer under this rate option. The aggregated Customer must provide a single point of contact for a request to Curtail.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{(\text{Maximum Demand during Peak Period x 1573 hours})}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

NEWFOUNDLAND POWER INC.
PROPOSED CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Limitations on Requests to Curtail:

Curtailment periods will:
1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced for failure to Curtail in a winter period as follows:

1. For the first 5 curtailment requests the Curtailment Credit will be reduced 25% for each failure to Curtail.

2. After the 5th curtailment 50% of the remaining Curtailment Credit, if any, will become vested ("Vested Curtailment Credit").

3. For all remaining curtailment requests the Curtailment Credit will be reduced by 12.5% for each additional failure to Curtail.

If a Customer fails to Curtail four times during a winter period, then:

1. The Customer shall only be entitled to the Vested Curtailable Credit, if any.

2. The Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraphs, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

NEWFOUNDLAND POWER INC.
PROPOSED CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

Supply Cost Mechanisms

March 2016

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 BACKGROUND

1.1 Introduction

This is a report on the results of a review of the regulatory mechanisms that affect the power supply costs of Newfoundland Power.

Amongst other things, this review specifically included (i) a survey of supply cost recovery practices of other investor-owned distribution utilities in Canada; (ii) the performance of Newfoundland Power's regulatory mechanisms that impact purchased power costs; and (iii) a review of the incentive effects of the regulatory mechanisms including an assessment of whether alternative regulatory mechanisms would improve the incentive for the Company to reduce purchased power costs.

The principal supply cost mechanism for Newfoundland Power is its Rate Stabilization Account ("RSA"). The RSA was created primarily as a means of ensuring that variations in Newfoundland and Labrador Hydro ("Hydro") production costs which were captured in Hydro's Rate Stabilization Plan ("RSP") were recovered in, or credited to, Newfoundland Power's customer rates in a timely fashion. The RSA still serves this purpose. The RSA also serves as a means of crediting to, or recovering from, customer rates variations in Newfoundland Power's purchased power expense. This report will consider the RSA principally in the context of Newfoundland Power's purchased power expense and related regulatory mechanisms, not in the context of Hydro's RSP.

1.2 Newfoundland Power's Supply Costs

Newfoundland Power is dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers.[1] Purchased power expense is Newfoundland Power's largest cost, accounting for almost two-thirds of revenue from rates in 2015.

Newfoundland Power's single supply dependence is relatively rare for investor-owned electric utilities in Canada.[2] Currently, the Company effectively recovers its power supply costs through a combination of customer rates and regulatory mechanisms.

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1 Currently, Newfoundland Power purchases approximately 93% of its power supply requirements from Hydro. Newfoundland Power has no practical alternative to Hydro for the additional power supply required to meet increasing customer load.

2 In Ontario and Alberta, energy supply for distribution to consumers is coordinated at a wholesale level by independent market operators which effectively ensure least cost supply on a real-time basis through competitive bidding. In Nova Scotia, Prince Edward Island and British Columbia, electric utilities are practically able to seek competitive sources of energy supply in regional wholesale markets. Saskatchewan, Manitoba, New Brunswick, and Quebec do not have investor-owned electric utilities.

Table 1 shows revenue and purchased power expense for Newfoundland Power on a kWh basis for 1995, 2005 and 2015.

Table 1
Revenue and Purchased Power Expense
1995, 2005 and 2015
¢ per kWh

	1995	**2005**	**2015**
Revenue	7.73	8.39	10.96
Purchased Power Expense	4.36	5.11	7.09
Purchased Power Expense as % of Revenue	56%	61%	65%

Over the last 20 years, Newfoundland Power's electricity rates and revenues have increased primarily as a result of increased purchased power expense. Over the last 10 years, purchased power expense has increased as a proportion of Newfoundland Power's revenue. On a kWh basis, almost 85% of the change in Newfoundland Power's revenues over this period is attributable to increased purchased power expense.[3] Purchased power expense is substantially beyond management control in any year.

2.0 REGULATORY MECHANISMS

2.1 National Overview

Mechanisms that permit full recovery of energy supply costs by investor-owned distribution utilities are commonplace in Canadian regulatory practice.[4] The widespread use of such regulatory mechanisms simply reflects that, in both the electricity and the gas distribution business, the cost of supply is typically the largest single cost.

Appendix A is a summary of current supply cost recovery practices for regulated investor-owned distribution utilities in Canada.

2.2 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved a definition of a Demand Management Incentive ("DMI") Account to be included in the Company's system of accounts.

The DMI Account is charged or credited with the amount by which the demand supply cost variance exceeds the demand management incentive which is ±1 percent of test year wholesale demand charges.

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3 Change in unit supply costs of 2.7¢ divided by change in unit revenues of 3.2¢ equals 84%.
4 Such regulatory mechanisms also appear to be commonplace in the U.S. See *Expert Evidence of Concentric Energy Advisors, Appendix A, Comparison to U.S. Electric Utility Proxy Group*, page 28, lines 17 to 24.

Table 2 shows a summary of the demand cost variations for the years 2010 through 2015, with a breakdown of the savings allocation between the Company and its customers.

Table 2
DMI Account
Demand Cost Variations
($000s)

	2010	2011	2012	2013	2014	2015
Demand Cost Variance[5]	(1,539.4)	(2,345.8)	(1,330.7)	965.3	(1,221.5)	58.8
Company (Savings) Cost	(545.2)	(545.2)	(545.2)	582.2	(594.0)	58.8
Customer (Savings) Cost	(994.2)	(1,800.6)	(785.4)	383.1	(627.5)	-

Since 2010, the operation of the DMI Account has resulted in net demand cost savings to the benefit of both customers and the Company. Since 2010, approximately $3.8 million of the $5.4 million in cumulative net savings has been credited to the benefit of Newfoundland Power's customers.

Newfoundland Power files an annual application with the Board by March 1st to address the disposition of any balance in the DMI Account. Any required recovery from, or credit to, customers arising from a DMI balance is typically included in the Company's annual RSA adjustment.[6]

2.3 Energy Supply Cost Variance Clause

Changes in the Company's purchased power expense related to variances in customers' load requirements are captured by the energy supply cost variance clause. Newfoundland Power's load requirements increase annually, principally as a result of the connection of new customers. The Company is obligated to provide service to new customers.

5 The demand cost variance is derived from test year unit demand cost. Transfers to reserves are on an after-tax basis. Benefits credited to customers through amortizations or through the RSA are effectively on a before-tax basis.

6 By Order Nos. P.U. 7 (2011), P.U. 9 (2012), P.U. 8 (2013), P.U. 7 (2014), and P.U. 8 (2015), the Board approved the disposition to customers of the balance resulting from the operation of the DMI Account in 2010, 2011, 2012, 2013 and 2014, respectively, through the annual RSA adjustment. Section II(6) of the Rate Stabilization Clause provides for adjustments to the RSA upon order of the Board.

Table 3 shows Newfoundland Power's marginal supply costs from Hydro and the average supply costs recovered in customer rates for 2010 through 2016F.

Table 3
Energy Supply Cost[7]
2010 to 2016F
(¢/kWh purchased)

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016F**
Average	5.6	5.6	5.6	5.6	5.9	5.9	6.4
Marginal	8.8	8.8	8.8	8.8	8.8	8.8	9.5
Difference	**(3.2)**	**(3.2)**	**(3.2)**	**(3.1)**	**(2.9)**	**(2.9)**	**(3.1)**

Table 3 shows that wholesale energy cost dynamics on the island of Newfoundland have been such that the cost to Newfoundland Power of the additional energy supply required to serve new customers is greater than the average energy supply cost reflected in customer rates.[8] This annual shortfall of approximately 3.0 ¢/kWh is expected to continue, at a minimum, until interconnection to the North American grid.

This shortfall impairs Newfoundland Power's ability to recover not only its purchased power costs from Hydro but also its own costs of providing service. To ensure reasonable recovery by Newfoundland Power of this increased supply cost without the requirement for a general rate application, the Board approved the annual recovery of energy cost variances through the RSA.[9]

Table 4 shows energy supply cost variances captured by the energy supply cost variance clause from 2010 through 2016F.

Table 4
Energy Supply Cost Variances
($000s)

2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016F**
2,213	6,896	9,727	7,836	1,838	3,600	4,677

Any required credit to, or recovery from, customer rates arising from energy supply cost variances are included in the Company's annual RSA adjustment.

7 Based on January prices.
8 This wholesale energy cost dynamic has existed since the Energy Supply Cost Variance mechanism was initially approved in 2007.
9 This was first approved in Order No. P.U. 32 (2007) and continued by Order No. P.U. 43 (2009).

2.4 Weather Normalization Reserve

Newfoundland Power's Weather Normalization Reserve normalizes the effects of weather and hydrology on the Company's sales and purchased power expense.[10]

Table 5 shows annual Weather Normalization Reserve transfers from 2010 through 2015.

Table 5
Weather Normalization Reserve
Transfers (To) From
($000s)

	2010	2011	2012	2013	2014	2015
Annual transfers to the Weather Normalization Reserve[11]	(5,873)	(3,065)	216	(1,712)	33	4,411
Annual transfers to the RSA	-	-	-	(216)	1,712	(33)
Amortization of 2011 balance	-	-	-	1,673	1,673	1,673

Beginning in 2013, the Board approved, in Order No. 13 (2013), the transfer of the annual balance in the Weather Normalization Reserve to the RSA.[12] In this order, the Board also approved the 3-year amortization of the 2011 year-end reserve balance due to customers.[13] This amortization is reflected in current customer rates.

3.0 ASSESSMENT

3.1 General

Newfoundland Power's purchased power expense accounted for approximately 65% of the Company's revenue in 2015. The Company's current supply cost recovery mechanisms essentially provide the Company with the reasonable opportunity to recover this expense.

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10 The Weather Normalization Reserve has two components: the Hydro Production Equalization Reserve (the "Hydro Component") and the Degree Day Normalization Reserve (the "Degree Day Component"). The Hydro Component effectively adjusts for the effects on purchased power expense that result from abnormal stream-flows to the Company's hydro-electric plants. The Degree Day Component effectively adjusts for the effects of abnormal weather (i.e., temperature and wind speed) on contribution from sales (i.e. change in revenue from rates less change in purchased power expense). The Hydro Component of the Weather Normalization Reserve was approved in Order No. P.U. 32 (1968) and the Degree Day Component was approved in Order No. P.U. 1 (1974).

11 Annual transfers to the Weather Normalization Reserve for 2010 to 2012 include an annual amortization of ($1.4) million as a result of Order No. P.U. 32 (2007), where the Board approved recovery of approximately $6.8 million through customer rates over a five year period.

12 By Order Nos. P.U. 11 (2013), P.U. 11 (2014), and P.U. 11 (2015), the Board approved the disposition to customers of the balance resulting from the operation of the Weather Normalization Reserve in 2012, 2013 and 2014, respectively, through the annual RSA adjustment.

13 The 2011 year-end balance of approximately $5.0 is being amortized over a three year period ending in 2015.

Regulatory mechanisms which provide a utility with a reasonable opportunity to recover its prudently incurred supply costs are consistent with both sound public utility regulation and current Canadian practice. Such mechanisms are routinely commented upon favorably by credit rating agencies.[14]

3.2 Incentive Effects

3.2.1 Incentives to Demand and Energy Conservation

Newfoundland Power has both financial and customer service incentives to foster conservation of demand and energy by its customers.

From a financial perspective, the DMI Account provides Newfoundland Power an incentive to reduce demand which is equal to the cost of ±1% of its annual peak each year, or approximately $1.2 million.[15] This translates into approximately 25% of the 36 basis point range of return on rate base typically approved by the Board for Newfoundland Power. The Company's response to this incentive has reduced purchased power expense from what it otherwise would have been and operation of the DMI Account has provided tangible benefits to customers.

From a customer service perspective, Newfoundland Power's customers have indicated that they wish to lower their energy bills. Newfoundland Power's satisfaction of its customers' service expectations in this regard provides a customer service incentive for the Company to take reasonable steps to foster energy conservation by its customers. Newfoundland Power has responded reasonably to this incentive.[16] This response has reduced Newfoundland Power's purchased power expense from what it otherwise would have been and provided tangible benefits to its customers.

3.2.2 Regulatory Policy Analysis

The justification of Newfoundland Power's current supply cost mechanisms reflects a combination of current dynamics related to production, wholesale and retail pricing, and customer end use on the island interconnected grid.

Hydro's Holyrood generating station is both a significant contributor to annual energy production and is the marginal source of supply on the island interconnected grid. Holyrood fuel costs are highly variable and justify the current mechanisms which provide for fuel recovery through Hydro's RSP and Newfoundland Power's RSA.

Wholesale and retail pricing on the island interconnected grid affects supply cost mechanisms in at least 2 significant ways. Firstly, Hydro's current wholesale utility rate design was explicitly

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[14] See for example the credit opinions of Moody's Investors Services and Dominion Bond Rating Service which are *Exhibit 4, (1st Revision)*, in *Volume 2, Exhibits & Supporting Materials*.

[15] Based upon the 2014 test year.

[16] Newfoundland Power's response has been to jointly promote with Hydro a customer energy conservation portfolio which is aimed at reducing customer energy usage and, in turn, reducing the production costs of Hydro. For more detail on this program portfolio; its costs and impacts; and plans for its expansion; see Section 2.2.2.

created to encourage demand conservation by Newfoundland Power.[17] The DMI Account achieves this. Secondly, current wholesale utility rate design and retail rate design combine to ensure that, following a test year, Newfoundland Power effectively serves new customers at a loss.[18] The energy supply cost variance clause avoids the alternative of more frequent general rate applications.

Newfoundland Power continues to serve a substantial heating load. Variations in weather, therefore, can have a substantial affect on the Company's purchased power expense. The Weather Normalization Reserve effectively addresses the relatively high impact of weather for Newfoundland Power.[19]

The Company's current supply cost mechanisms specifically meet local regulatory policy objectives and are consistent with current Canadian regulatory practice. No superior mechanisms in terms of incentive effects or otherwise were identified by Newfoundland Power in the review.

4.0 CONCLUSION

This review indicated that current mechanisms which provide for the Company's recovery of prudently incurred supply costs remain consistent with sound public utility practice and current Canadian regulatory practice. The review also indicated existing mechanisms provide reasonable incentives for the Company to foster customer conservation of demand and energy. These incentives have yielded tangible results that benefit customers.

As a result, the Company is not proposing any changes to these regulatory mechanisms.

17 For example, in Order No. P.U. 44 (2004), the Board indicated at page 10 that a key question for it was whether there was "….sufficient incentive for [Newfoundland Power] to implement load management and conservation programs aimed at reducing demand growth on the system, and hence reduce its purchased power costs through a lower billing demand."

18 This dynamic was recognized by the Board in Order No. P.U. 32 (2007) when, in approving the energy supply cost variance clause, it observed at page 27 that "The recovery of variances in energy supply costs through the Rate Stabilization Account will allow [Newfoundland Power] to recover its prudently incurred energy supply costs without the necessity of filing a general rate application, which is consistent with the Board's goal of enhanced regulatory efficiency."

19 All Canadian investor-owned gas or electric distribution utilities surveyed by Newfoundland Power that serve substantial heating loads have regulatory mechanisms which effectively provide for full recovery of supply costs after consideration of the effects of weather (See Appendix A).

Supply Cost Recovery Practices for Regulated Investor-owned Distribution Utilities in Canada

	Province	Supply Cost in Customer Rates	Flow-through Mechanism	Mechanism Description
Electric Utilities				
Maritime Electric	PEI	Yes	Yes	Energy Cost Adjustment Mechanism that provides for recovery or refund to customers of the variation from test year energy supply costs. (See Note 1)
FortisOntario	Ontario	Yes	Yes	Variance account to capture price differentials between the actual supply cost and supply cost reflected in customer rates. (See Note 2)
FortisAlberta	Alberta	No	Not Required	(See Note 3)
ATCO Electric	Alberta	No	Not Required	(See Note 3)
FortisBC	BC	Yes	Yes	Rate Stabilization Deferral Mechanism Account (RSDM) used to mitigate rate variability over the PBR Period.
Gas Utilities				
GazMetro	Quebec	Yes	Yes	Rate stabilization regulatory mechanisms to account for the impacts of weather and the cost of energy. Balance disposition in subsequent year(s).
Union Gas	Ontario	Yes	Yes	Rates are adjusted on a quarterly basis and the difference between the cost of gas reflected in rates and the actual cost of gas is deferred. Disposition of the forecast balances in the deferral account occurs over the subsequent 12 months.
Enbridge Gas Distribution	Ontario	Yes	Yes	The difference between the cost of gas in rates and the actual cost of gas is deferred to be recovered from, or refunded to, customers through a quarterly adjustment mechanism. There is also a true-up account to recover the financial impact of variances from forecast average use for residential and commercial sectors.
ATCO Gas	Alberta	No	Not Required	(See Note 3)
AltaGas Utilities	Alberta	Yes	Yes	A Gas Cost Recovery Rate (GCRR) is updated monthly to ensure the actual cost of gas is recovered from customers. (See Note 4)
FortisBC Energy	BC	Yes	Yes	Rate stabilization mechanisms to mitigate the effect on earnings of volume volatility due to the effects of weather and natural gas cost volatility. (See Note 5)
Pacific Northern Gas	BC	Yes	Yes	Regulatory mechanisms to mitigate the effect on earnings of volume volatility and natural gas cost volatility. (See Note 6)

Notes:

(1) The Energy Cost Adjustment Mechanism ("ECAM") adjusts for monthly variances from the 8.760 ¢ per kWh test year energy supply cost, and the balance is recovered or refunded, as appropriate, over a rolling 12-month period. The PEI Energy Accord currently stipulates the term of the disposition of the balance related to the ECAM.

(2) The Electricity Distribution Rate Handbook approved by the Ontario Energy Board provides for a purchased power variance/deferral account for distribution utilities to capture price differentials between the actual electricity supply costs and the supply cost reflected in customer rates.

(3) FortisAlberta, ATCO Electric, and ATCO Gas own and operate assets that provide distribution service under Alberta Utilities Commission approved distribution tariffs. Distribution tariffs provide for a recovery of the cost of distribution service including a fair return. Electricity and gas supply costs are not considered a cost of these utilities' provision of distribution service. Supply costs are a separate component on customers' bills.

(4) The GCRR is updated monthly to reflect an estimate of the cost of gas and gas supply-related management and administration costs for the upcoming month and to adjust for any deficit or surplus from the previous month.

(5) Two rate stabilization mechanisms are used at FortisBC Energy.

The first relates to recovery of gas costs through two deferral accounts which capture all variances (overages and shortfalls) from forecasts gas costs. The deferral accounts are called the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA).

The second mechanism stabilizes delivery revenues from the residential and commercial classes through a deferral account that captures variances in the forecast versus actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism (RSAM). If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, Terasen records the delivery charge differences in the RSAM deferral account.

The BCUC has issued guidelines for quarterly calculations to be prepared to determine whether customer rate adjustments are needed to reflect the market price of natural gas and to ensure that rate stabilization account balances are recovered on a timely basis.

(6) Two rate stabilization mechanisms are used at Pacific Northern Gas.

The first in the Gas Cost Variance Account which is utilized to record variances in the actual cost of gas and the cost reflected in customer rates.

The Revenue Stabilization Adjustment Mechanism adjusts revenue from residential and small commercial customers by a deferral account that records differences between forecast and actual deliveries.

When deliveries to customers vary from forecast, balances accumulate in the accounts which are recovered, or refunded, as appropriate in future rates to customers.