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September 20, 2013

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (2014-18 PBR Plan Application)

Errata 2 to 2014-18 PBR Plan Application

FBC provides the following errata to its Application for approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (2014-18 PBR Plan Application). Replacement pages are attached.

1 **2014-18 PBR Plan Application, Section B6.3.2: Flow-Through Expenses, page 62, lines 23-24**

Sentence should read, "Flow-through revenues are amounts received from customers for the sale of electricity."

2 **2014-18 PBR Plan Application, Section C5: Capital Expenditures, Table C5-1, page 179**

Kootenay Long Term Facility ($7.980 million) and Okanagan Long Term Solution ($0.031 million) inadvertently included as Other – Regular Capital. Both projects have been appropriated classified as Other – Major Project.

3 **2014-18 PBR Plan Application, Section D2.4.2: Discontinuation of Net of Tax Treatment for Pensions and OPEBs, page 243, lines 7-9**
Last sentence of the paragraph deleted.

4 **2014-18 PBR Plan Application, Section D4: Deferral Accounts, page 260, lines 9-12**
“”2.4 million” should read “$3.9 million”
“$(2.5) million” should read “$(1.5) million”
“16.6 million” should read “$16.2 million”

5 **2014-18 PBR Plan Application, Appendix B2: Key Operating Facts, 2012 Total Year End Direct Customers, 2012 SAIDI**
Residential Customer Count of “98,228” should read “99,228”
Total Year End Direct Customers of “112,915” should read “113,915”
SAIDI of “2.00” should read “1.95”

6 **2014-18 PBR Plan Application, Appendix E2: Monthly Load Forecast, Section 2: Weather Normalization, Table E2-1, page 7**
Residential HDD value of 172 missing for December.

7 **2014-18 PBR Plan Application, Appendix E2: Monthly Load Forecast, Section 3.3: Energy Forecast, page 9, lines 6-7**
Sentence should read: “Before-savings load includes DSM impacts up to 2012 but without incremental DSM savings from 2013 on.”

8 **2014-18 PBR Plan Application, Appendix E2: Monthly Load Forecast, Section 3.3: Wholesale, page 16, line 11**
“March 31, 2014” should read “March 31, 2013”

9 **2014-18 PBR Plan Application, Appendix E2: Monthly Load Forecast, Section 3.7: CoK Load Forecast, page 21, line 6**
“of the net” should read “in the gross”

10 **2014-18 PBR Plan Application, Appendix E2: Monthly Load Forecast, Section 3.8: DSM and Other Savings, page 22, line 14**
“5.9” should read “3.3”

If you require further information or have any questions, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc (e-mail only): FBC 2014-18 Multi-Year PBR Plan Interveners

Taxes

FBC proposes that variances in property tax expenses, income tax rates, and other tax items be captured in deferral accounts. Projected deferral account balances and forecasts of tax expenses will be provided each year during the Annual Review process.

Pension and OPEB Expenses and Insurance Costs

These items are subject to deferral account treatment. Pension and OPEB expenses, and insurance expenses will be re-forecast at each Annual Review based on the most recent information provided by actuaries and FBC's insurance provider. Projected year-end deferral account balances will also be provided at the Annual Reviews.

Power Purchase Expense

Variances in Power Purchase Expense from amounts included in rates arise from factors outside of FBC's control, including load variances due to variances in customer growth, usage, or weather; unit price variances from forecast, including market prices compared to forecast and regulated price changes (BC Hydro rates and other contracts whose prices are tied to BC Hydro rates) not known at the time of application; and factors related to the operation of the Canal Plant Agreement governing FBC's generation plants, which affect the Company's usage or timing of entitlements. FBC also flows through the benefits of its ability to displace BC Hydro purchases with lower-cost market purchases. All such variances are deferred and returned or recovered in future rates as approved by Order G-110-12.

Power Purchase Expense will be forecast each year at the Annual Review and included in the determination of the revenue requirement and rates for the forecast year.

Revenues

Flow-through revenues are amounts received from customers for the sale of electricity.

The majority of variances in sales revenue are attributable to weather-related load variances, customer usage rate variances and customer count load variances which are not under the control of FBC. FBC's Revenue Variance Deferral Account was approved by Order G-110-12.

Revenues will be forecast each year at the Annual Review and these revenues will be included in the determination of the revenue requirement and rates for the forecast year.

Depreciation and Amortization

As discussed in section B6.2.5, the 2014 Plan proposes to derive the annual regular capital expenditures by means of formulas. The formula-based capital expenditures are carried forward in the rate base throughout the PBR term without adjusting the amounts to the actual spending levels (unless total capital expenditure spending deviates in any year by more than 10 percent from the formula amounts). Annual depreciation expense will be based on the approved depreciation rates and the opening plant account balances which include plant additions consistent with the formula-based capital expenditures. The incentive power of the formula-based capital elements of the PBR Plan relates to finding ways to be more efficient in

Table C5-1: Historical FBC Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Approved	2013 Projection
Generation - Regular Capital	3,589	2,128	4,386	4,039	2,363	2,823
Generation - Major Projects	13,966	13,828	2,599	2,935	-	425
Total Generation Capital	17,555	15,956	6,985	6,973	2,363	3,248
Transmission-Station-Distribution Regular Capital	42,999	34,719	29,731	45,130	36,591	52,031
Transmission-Station-Distribution Major Projects	61,489	13,389	6,003	10,892	11,886	45,230
Total Transmission-Station-Distribution Capital	104,488	48,108	35,734	56,022	48,477	97,261
Other - Regular Capital	8,448	11,605	7,974	10,689	8,134	10,755
Other - Major Projects	-	540	1,700	9,367	42,996	21,929
Total Other Capital	8,448	12,145	9,674	20,056	51,130	32,684
Total Gross Capital Expenditures	130,491	76,209	52,393	83,052	101,970	133,193

5.3.3 Base and Forecast Capital Expenditures

In order to set the base level of capital expenditures for application of the PBR formula, FBC uses 2013 Approved capital expenditures as a starting point, less those expenditures which are not representative of on-going requirements. Finally, similar to the method of determining 2013 Base O&M Expense, certain factors that will impact capital expenditures in future, but which were not accounted for in 2013, are added. As discussed in Section B6 of the Application, the adjustments reflect:

1. Elimination of major or non-recurring types of capital;
   - Corra Linn Unit 3 completion;
   - Corra Linn Unit 2 Life Extension;
   - Okanagan Transmission Reinforcement Project;
   - Kelowna Bulk Transformer Capacity Addition;
   - PCB Environmental Compliance (substations component);
   - Trail Office Lease Purchase;
   - Kootenay Long Term Facilities Project;
   - Okanagan Long Term Solution Project;
   - Central Warehousing Project; and
   - Advanced Metering Infrastructure Project.
2. The return to PST; and
3. The capital portion of increased 2013 pension amounts.

of tax recognition on these employee future benefit deferral accounts would be consistent with the treatment approved by the BCUC pursuant to G-141-09 for FEI.

In summary, FBC has included the pension and OPEB funding differences in deferral accounts. The existing net-of-tax balances of the pension and OPEB will be carried forward as a starting point for 2014, but future additions to both accounts will be on a pre-tax basis with the timing of tax deductions recognized in the calculation of income tax expense.

2.5 CONCLUSION

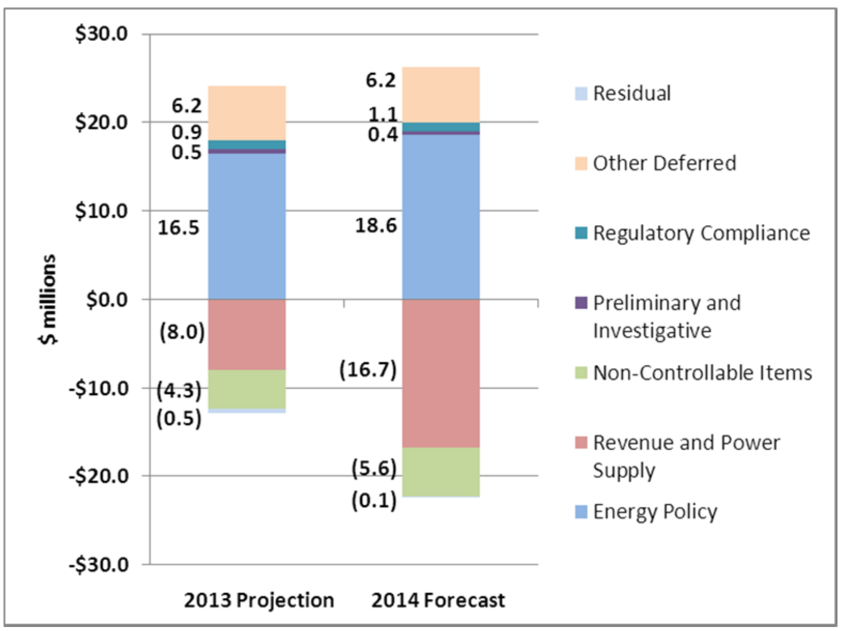
FBC will continue to incur income taxes, property taxes and other taxes that are imposed by different government bodies. The tax expenses included in this Application reflect the current enacted tax legislation that has been applied in calculating the PBR Period forecasts for FBC.

D3.1, FBC is proposing to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense.

Similarly, Preliminary and Investigative Charges are either charged to capital or expensed and are not tax-effected

The forecast mid-year balance of unamortized deferred charges in rate base for FBC is approximately $3.9 million in 2014 as balances in the Demand Side Management and debt issue costs are largely offset by the deferred Power Purchase Expense and the Rate Stabilization Deferral Mechanism Account described in Section D4.3.1 below. The forecast mid-year balances range from $(1.5) million to $16.2 million in 2015 to 2018; however the actual balances to be recovered in rates for these future years will be addressed in the annual rate setting process. Figure D4-1 provides the mid-year deferral account balances summarized by deferral account category.

Figure D4-1: Forecast Mid-Year Balances of Deferral Accounts by Category



The section below includes a discussion on new rate base deferral accounts and changes to existing rate base deferral accounts, including discontinuing the use of many deferral accounts that are no longer required. With respect to FBC's other currently approved accounts, the original rationale that justified establishing the accounts. They are expected to continue to accumulate new amounts during the PBR Period, and should remain in place. A summary of all existing and proposed rate base deferral accounts can be found in Appendix F4. For a discussion on non-rate base deferral accounts, please refer to Section D4.7 below.

FBC
Annual Report Statistics
2005-2012

	2005	2006	2007	2008	2009	2010	2011	2012
Direct Customers:								
Residential Customers	86,192	89,181	93,647	95,502	96,565	97,883	98,795	99,228
Commercial Customers	10,209	10,285	11,010	11,216	11,308	11,419	11,525	11,811
Industrial Customers	39	37	38	36	33	36	39	39
Wholesale Customers	8	8	7	7	7	7	7	7
Lighting & Irrigation	3,131	2,902	3,022	2,958	2,940	2,905	2,895	2,830
Total Year End Direct Customers	**99,579**	**102,413**	**107,724**	**109,719**	**110,853**	**112,250**	**113,261**	**113,915**
Indirect Customers	49,621	49,762	46,334	47,809	48,444	48,769	49,033	49,149
Energy Sales (Normalized Actual):								
Residential (GWh)	1,070	1,091	1,160	1,221	1,293	1,224	1,260	1,220
Commercial (GWh)	568	598	636	666	672	654	652	680
Industrial (GWh)	357	344	352	252	203	234	282	291
Wholesale (GWh)	916	948	881	892	928	881	896	901
Lighting & Irrigation (GWh)	56	59	62	56	61	53	53	52
Total Energy Sales	**2,967**	**3,040**	**3,091**	**3,087**	**3,157**	**3,046**	**3,143**	**3,144**
Cost of Electricity (Normalized)								
Average Cost of Electricity Sold ($/kWh)								
O&M:								
Gross O&M Decision ($000s)	$ 39,629	$ 41,908	$ 43,093	$ 45,310	$ 46,573	47,645	53,885	54,843
Gross O&M Actual ($000s)	41,072	40,719	43,001	44,725	46,017	46,148	53,076	53,542
Capitalization Allowed ($000s)	$ (3,392)	$ (8,382)	$ (8,836)	$ (9,062)	$ (9,315)	$ (9,529)	$ (10,777)	$ (10,969)
Total Net O&M ($000s)	**$ 37,680**	**$ 32,337**	**$ 34,165**	**$ 35,663**	**$ 36,702**	**$ 36,619**	**$ 42,299**	**$ 42,574**
Headcount								
Full Time Equivalent (FTE)	431	496	532	545	540	534	528	542
Transmission & Distribution Stats:								
Distribution Lines (km)	4,992	4,978	5,468	5,547	5,560	5,603	5,630	5,648
Transmission Lines (km)	1,393	1,514	1,382	1,449	1,393	1,390	1,408	1,394
Total Transmission and Distribution Lines (km)	6,385	6,492	6,850	6,996	6,953	6,993	7,038	7,042
Total Substations	64	64	64	64	66	64	65	65
System Losses (%) - Gross Load	11.3	10.7	9.4	9.2	9.2	8.4	8.9	7.9
Peak Demand (MW) - Summer	512	554	569	537	561	554	519	551
Peak Demand (MW) - Winter	708	718	683	746	714	707	669	737
Power Supply Stats:								
Generation (GWh)	1,633	1,509	1,498	1,610	1,586	1,530	1,527	1,531
Generating Capacity (MW)	214	235	223	223	223	223	223	223
Total Power Purchases (GWh)	1,713	1,895	1,912	1,791	1,893	1,796	1,924	1,882
Total DSM Energy Saved (GWh)	23.9	23.2	28.4	27.3	29.7	28.8	36.3	31.6
System Outages:								
System Average Interruption Duration Index (SAIDI) (Normalized)	2.09	2.93	2.49	2.42	2.28	2.84	1.86	1.95
System Average Interruption Frequency Index (SAIFI) (Normalized)	3.07	4.18	1.99	2.13	1.48	2.27	1.38	1.27
Service Quality Indicators:								
Emergency Calls Responded to within 2 hours	89%	93%	92%	94%	92%	95%	92%	91%
% of Contact Centre Calls answered within 30 seconds	n/a	70%	70%	70%	70%	70%	70%	70%
Customer Satisfaction	8.1	8.5	8.6	8.6	8.6	8.8	8.7	8.4
Miscellaneous:								
Rate Base, Mid-Year ($000s)	$ 589,845	$ 671,138	$ 746,543	$ 802,566	$ 867,683	$ 945,637	$ 1,065,892	$ 1,088,470
Allowed Return	9.43%	9.20%	8.77%	9.02%	8.87%	9.90%	9.90%	9.90%

(c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder;

(d) add the normalization adder to the month's load (residential or wholesale).

The general equation to normalize energy requirements in month t is shown below.

Normalized $\text{energy}_t = \text{Energy}_t - \text{HDD slope}_t{*}(\text{HDD}_t - \text{Normal HDD}_t)$ for t = 3-5, 9-10, 11-2,

Normalized $\text{energy}_t = \text{Energy}_t - \text{CDD slope}_t{*}(\text{CDD}_t - \text{Normal CDD}_t)$ for t = 6- 8

Regression slopes (MWh/degree day) and 10-year average degree days, taken over the 2003-2012 period for 2013 weather normalization, are found in the following table.

Table E2-1: Weather Normalization Coefficients and Normal Weather for 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential HDD	172	172	111	111	111	-	-	-	84	84	172	172
Residential CDD	-	-	-	-	-	132	132	132	-	-	-	-
Wholesale HDD	90	90	60	60	60	-	-	-	30	30	90	90
Wholesale CDD	-	-	-	-	-	75	75	75	-	-	-	-
Normal HDD	577	483	398	275	137	44	5	8	84	270	448	579
Normal CDD	-	-	-	-	6	32	126	94	11	-	-	-

Table E2-1 illustrates that an additional HDD in February causes energy use to rise by 172 MWh for the residential sector, while an extra HDD in May causes consumption to rise by only 111 MWh.

The Company also investigated possible global warming effects through a long-term (30-year) trend analysis of HDD and CDD, but no statistically significant trend of increasing temperature was found for any month except for July as summarized below. Therefore, this load forecast does not explicitly address global warming effects. This is in line with the current utility practice according to recent surveys[6].

[6] Hydro One's survey of weather normalization practice in 2008, as reported in their Rate Application in May 2012http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20A/A-15-02.pdf (p.13, accessed on April 10, 2013.)

3. ENERGY FORECAST

This section discusses methodologies to forecast energy requirements for different load classes for both before and after saving. Saving here is defined as the sum of DSM and other savings, including the Residential Conservation Rate (RCR), Customer Information Portal (CIP), Advanced Metering Infrastructure Project (AMI), and rate-driven impacts. Note that the RCR, the CIP, and AMI forecasts are only available for the residential class. Before-savings load includes DSM impacts up to 2012 but without incremental DSM savings from 2013 on. A general formula for an after-saving load in year *t* is

$$\text{After-saving Load}_t = \text{Before-saving Load}_t - \text{Saving}_t$$

The integration of City of Kelowna (CoK) load, which consists of the residential, commercial, and industrial classes, to the FBC direct service system on March 31, 2013 will create a decrease in the wholesale load and increases in the corresponding load classes in 2013. The integration impacts will be fully observed in 2014. To clearly present the load forecasting process, sections 3.1, 3.2, and 3.4 discuss the residential, commercial, and industrial loads with and without the CoK integration in this order. Details of CoK load forecast are given in section C.7. Section 8 gives details of the DSM and other savings.

3.1 RESIDENTIAL

The formula to forecast the expected before-saving residential load in year *t* is

$$\text{Before-saving Load}_t = \text{UPC}_t\text{*Average Customer Count}_t,$$

where UPC (use per customer, MWh per customer per year) is before-saving.

Statistical tests showed no clear trend for the before-saving UPCs (Figure E2-1.) Therefore, the before-saving UPC for 2014 was forecast at 12.63 (MWh per customer per year) as the average of historical normalized UPCs in the previous three years 2010-2012. This value was then assumed to remain constant throughout the period due to offsetting impacts of factors that increase load (e.g. there are more appliances to suit more comfortable lifestyle) and decrease load (e.g. appliances are more energy-efficient).

Table E2-3: Before-saving UPC without CoK

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UPC	12.74	12.64	12.90	12.77	12.70	12.41	12.63	12.63	12.63	12.63	12.63	12.63

3.3 WHOLESALE

Prior to the filing of the 2012-2013 RRA in 2011, the Company forecast its wholesale load using the results of load surveys from all wholesale customers. The response rate was always 100 percent, and FBC then summed over the Wholesale customers' forecasts to come up with the before-saving wholesale load forecast. The main assumption in this approach is that in the near to medium-term, the Wholesale customers have the best knowledge of their service territory's load with respect to their customer mix, load behaviors, development projects with associated energy requirements, etc. For the 2012-2013 RRA, the Company was unable to use this approach because of the unavailability of the forecast for the City of Kelowna, which was a major component of the Wholesale forecast (accounting for around one third of the load.)

The integration of CoK into FBC direct service effective March 31, 2013 resolved this problem, and FBC resumed its past approach of seeking individual load forecasts for 2013-2018 from the Wholesale customers.

The table below summarizes the Wholesale customers' normalized load (including CoK load up to Q1 2013) and their before-saving load forecast for 2013-2018, as well as the whole class before and after-saving forecasts.

Table E2-11: Wholesale Load (GWh)

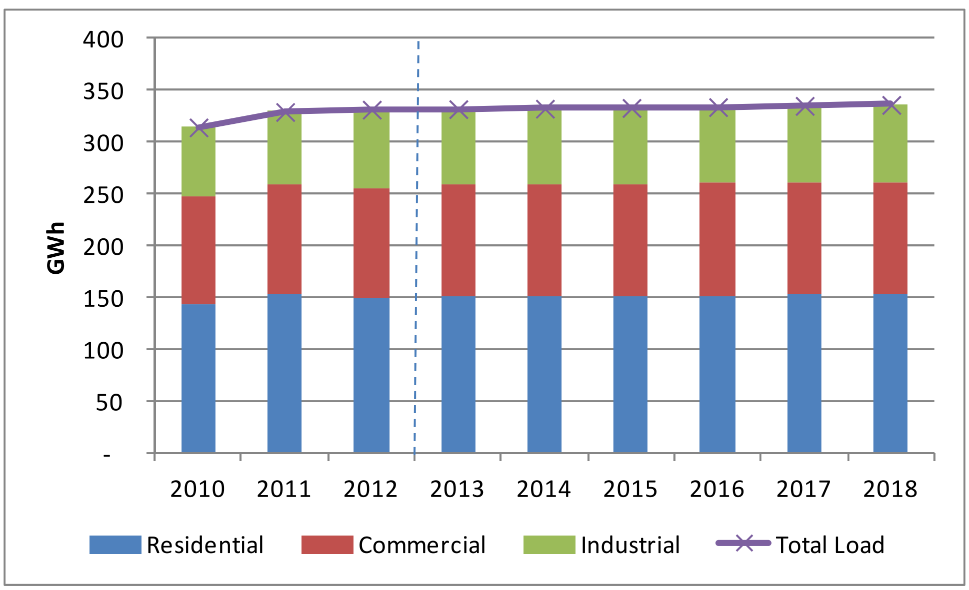
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
BCH Lardeau	9	7	6	9	8	6	8	8	8	8	8	8
BCH Kingsgate	3	3	4	3	3	5	4	4	4	4	4	4
City of Grand Forks	41	41	41	41	41	41	41	41	42	42	42	43
City of Nelson	85	106	109	90	88	80	89	90	91	92	93	94
City of Penticton	347	342	345	341	344	341	346	349	352	355	358	362
District of Summerland	98	91	77	97	96	95	98	99	100	101	102	103
City of Kelowna	292	308	323	314	329	332	96	-	-	-	-	-
Before-saving	**875**	**898**	**904**	**895**	**910**	**899**	**682**	**591**	**596**	**602**	**607**	**613**
After-saving							**677**	**581**	**584**	**587**	**590**	**594**

Table E2-16: CoK Energy (GWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Normalized/ Before-saving	314	329	332	333	335	337	338	340	342
Residential	143	154	150	151	152	153	154	154	155
Commercial	105	105	106	109	109	110	110	111	111
Industrial	67	71	76	73	74	74	74	75	75
After-saving				332	332	333	334	335	336
Residential				151	151	151	152	152	152
Commercial				108	108	108	108	109	109
Industrial				73	73	74	74	74	75

Figure E2-12 displays CoK after-saving loads.

Figure E2-12: COK Load (GWh)



The CoK integration does not result in any change in the gross load. It just reallocates CoK load from the wholesale sector to the residential, commercial, and industrial classes. As a result, there will be a decrease in the wholesale load in 2013, which is entirely offset by increases in the other three load classes. The full-year impacts are first observed in 2014.

3.8 DSM AND OTHER SAVINGS

Tables E2-17 and E2-18 display DSM by load class (excluding DSM already embedded in historical loads) for the current FBC system with the CoK integration and for the CoK itself respectively.

TableE2-17: DSM with CoK (GWh)

	2013	2014	2015	2016	2017	2018
Residential	5.8	13.0	17.2	21.3	25.4	29.4
Commercial	6.1	13.5	17.6	21.7	25.7	29.6
Wholesale	3.5	7.8	10.2	12.6	14.9	17.2
Industrial	0.9	2.1	2.8	3.6	4.5	5.3
Lighting	0.4	0.8	0.8	0.8	0.8	0.8
Irrigation	0.4	0.7	0.9	1.0	1.2	1.4
Net DSM	17.1	37.8	49.5	61.0	72.5	83.8

Table E2-18: DSM for CoK (GWh)

	2013	2014	2015	2016	2017	2018
Residential	0.3	0.8	1.0	1.2	1.5	1.7
Commercial	0.4	0.9	1.2	1.5	1.8	2.1
Industrial	0.0	0.1	0.1	0.1	0.1	0.2
Net DSM	0.8	1.8	2.3	2.9	3.4	4.0

Besides DSM programs administered by the PowerSense group, the Company also has other saving programs including Residential Conservation Rate (RCR), Customer Information Portal (CIP), Advanced Metering Infrastructure (AMI), and rate-driven. RCR, CIP, and AMI are currently forecast for the residential class only, including CoK load after the integration. RCR, CIP, and rate-driven impacts are calculated as percentage of the corresponding before-saving load. The rate-driven impact of 0.3 percent is the product of the assumed elasticity of -0.05 and the forecast average rate increase of 3.3 percent in 2014-2018. This saving is independent of the RCR saving and applied to all rate classes. In the absence of specific information with regards to price elasticity as presented in the RCR application, FBC has applied the assumption of -0.05[7] elasticity made by BC Hydro. BC Hydro is considered as the closest utility to FBC in terms of its public policies, geographical proximity, customer mix and behavior, and its assumed price elasticity of -0.05 has been well defended in a testimony for the BCH LTAP 2008[8]. In the

[7] BCH 2012 IRP, App. 2A, p. 14, http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix36.pdf, accessed as of April 12, 2013.

[8] http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/2008_ltap_appendix_e.pdf, accessed as of April 12, 2013