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December 22, 2020

Ms. Marija Tresoglavic
Acting Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Tresoglavic:

**RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2022 Revenue Requirements Application (the Application)**

BC Hydro is hereby filing the attached Fiscal 2022 Revenue Requirements Application. BC Hydro is requesting various approvals from the BCUC which, if approved, would result in a rate increase of 1.16 per cent.

We request that these changes be made effective April 1, 2021, on an interim basis, pending a final BCUC decision on the Application.

BC Hydro is providing the Application as follows:

Exhibit B-2	Application
Exhibit B-2-1	Application – Chapter 6 (Confidential Version)
Exhibit B-2-2	Appendices A to Y
Exhibit B-2-3	Appendices I and N (Confidential Version)
Exhibit B-2-4	Appendix Z (Confidential)

Confidentiality Request

BC Hydro requests the following information to be held confidential in accordance with Part IV of the BCUC's Rules of Practice and Procedure, for the reasons explained below:

1. Certain information in Chapter 6, Appendix I, and Appendix N, which is either customer-specific and/or commercially sensitive; and
2. The entirety of Appendix Z related to Mandatory Reliability Standards.

Chapter 6, Appendix I and Appendix N - Customer-Specific / Commercially Sensitive Information

In Chapter 6 and Appendix I, BC Hydro has redacted the name of a BC Hydro project where the project either:

- Is driven by, or specially for, a customer (disclosure of such information may prejudice a customer's commercial or competitive position); or
- Pertains to a substation acquisition (disclosure of such information may prejudice BC Hydro's position in future negotiations).

In Appendix N, the information redacted pertains to the name or identifiable information of a customer. If disclosed, the information may potentially prejudice the customer's competitive position. BC Hydro has a contractual obligation to keep the information specifically related to the customer and the customer's project confidential.

For the purpose of this proceeding and on appropriate undertakings, as contemplated by the BCUC's Rules of Practice and Procedure, BC Hydro is able to make non-customer specific project information in Chapter 6 and Appendix I available to registered interveners. BC Hydro reserves the right to object to a request for access to confidential information on a case-by-case basis.

Appendix Z – Confidential Mandatory Reliability Standards Information

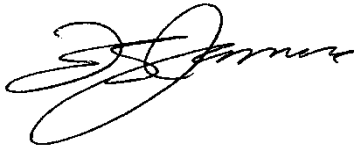
In the Application, we have split the discussion on Mandatory Reliability Standards (**MRS**) between public content in Chapter 5 and confidential content in Appendix Z. Appendix Z is confidential and made available to the BCUC only for two related reasons:

- First, information related to the protection of cyber infrastructure is highly security sensitive and could compromise the safety and reliability of the Bulk Electric System by exposing it to physical attacks by malicious actors or cyberattacks; and
- Second, the BCUC's MRS Rules of Procedure, including the Compliance Monitoring Program Rules and Penalty Guidelines, make the framework and processes for reporting, auditing and oversight of MRS compliance confidential. While certain information about an entity's violations, if confirmed, may become public after the fact, there remains a presumption of confidentiality. The presumption of confidentiality is especially important where the subject-matter relates to a cyber-security incident or may otherwise jeopardize the security of the Bulk Electric System.

December 22, 2020
Ms. Marija Tresoglavic
Acting Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Fiscal 2022 Revenue Requirements Application (the Application)

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

cs/rh

Enclosure

Copy to: BCUC Project No. 1598990 (BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application) Registered Intervener Distribution List.

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BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix A Financial Schedules

Revenue Requirements Model

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Note 1: RRA (Revenue Requirement Application); TRR (Transmission Revenue Requirement)

Revenue Requirements Summary
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Cost of Energy	3.0 L1	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
2	Operating Costs	3.0 L20	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,226.7
3	Provisions & Other	3.0 L26	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
4	Taxes	3.0 L32	223.1	231.1	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
5	Amortization	3.0 L35	777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
6	Finance Charges	3.0 L41	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
7	Return on Equity	3.0 L48	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
8	Miscellaneous Revenue	3.0 L52	(143.1)	(143.7)	(224.4)	(240.6)	(247.3)	(6.7)	(247.0)	(243.7)	3.3	(255.4)
9	Inter-Segment Revenue	3.0 L61	(56.9)	(66.4)	(62.5)	(64.9)	(72.0)	(7.1)	(71.9)	(97.4)	(25.5)	(83.5)
Deferral Accounts												
10	Deferral Account Additions	2.1 L40	63.3	203.7	586.0	3.1	52.2	49.1	3.5	(30.8)	(34.3)	15.5
11	Interest on Deferral Accounts	2.1 L41	(41.1)	(26.5)	8.2	15.4	15.9	0.5	4.0	4.8	0.8	0.7
12	Deferral Account Recoveries	2.1 L42	223.7	233.2	240.6	(392.5)	(403.9)	(11.4)	(238.3)	(238.3)	0.0	0.0
13	Total		245.8	410.4	834.7	(373.9)	(335.7)	38.2	(230.8)	(264.4)	(33.5)	16.2
Other Regulatory Accounts												
14	Regulatory Account Additions	2.2 L225	(46.8)	(237.7)	(636.4)	(279.2)	(984.2)	(705.0)	(144.7)	(382.7)	(238.0)	(112.1)
15	Interest on Regulatory Accounts	2.2 L226	(34.2)	(35.2)	(35.7)	(33.1)	(32.6)	0.5	(30.0)	(27.2)	2.8	(25.0)
16	Regulatory Account Recoveries	2.2 L227	(57.0)	(188.4)	956.9	381.4	287.7	(93.7)	379.2	272.6	(106.6)	340.6
17	Total		(138.0)	(461.2)	284.8	69.1	(729.1)	(798.3)	204.4	(137.3)	(341.7)	203.5
Subsidiary Net Income												
18	Powerex Trade Income		(130.2)	(136.6)	(435.7)	(176.3)	(189.2)	(13.0)	(176.3)	(176.2)	0.0	(190.1)
19	Powertech Net Income		(2.1)	(3.1)	(3.5)	(3.4)	(3.4)	0.0	(3.7)	0.0	3.7	(2.0)
20	Total		(132.4)	(139.6)	(439.1)	(179.7)	(192.7)	(13.0)	(179.9)	(176.2)	3.7	(192.1)
21	Less Other Utilities Revenue	14.0 L19	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
22	Less Liquefied Natural Gas Revenue	14.0 L20	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
23	Less Deferral Account Rate Rider	14.0 L23	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
24	Total Rate Revenue Requirement		4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,211.7
Rate Revenue at Current Rates												
25	Total Domestic Revenue	14.0 L24	4,709.7	4,895.5	5,067.2	5,144.8	5,115.1	(29.6)	5,087.4	4,904.6	(182.9)	5,182.4
26	Less Other Utilities	Line 21	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
27	Less Liquefied Natural Gas Revenue	Line 22	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
28	Less Deferral Account Rate Rider	Line 23	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
29	Revenue Subject to Rate Increase		4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,152.2
30	Revenue Shortfall	L24 - L29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	59.5
31	Rate Increases		4.00%	3.50%	3.00%	6.85%	6.85%	-	(1.62%)	(1.62%)	-	1.16%
32	Deferral Account Rate Rider		5.00%	5.00%	5.00%	-	-	-	-	-	-	-
33	Net Bill Impact		4.00%	3.50%	3.00%	1.76%	1.76%	-	(1.62%)	(1.62%)	-	1.16%
34	Total Rate Revenue Requirement	Line 24	4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,211.7
35	Rate Smoothing Regulatory Account transfers	2.2 L131	201.2	326.2	(814.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Revenue Requirement before transfers to Rate Smoothing Reg. Acct.		4,673.8	4,975.3	3,980.3	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,211.7

BC Hydro
F22 RRADeferral Accounts
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Heritage Deferral Account												
1	Beginning of Year		(23.9)	(53.1)	(103.7)	(485.1)	(485.1)	0.0	(225.6)	(300.1)	(74.5)	114.4
2	Adjustment to Opening Balance		(0.0)	0.0	(318.9)	0.0	0.0	0.0	0.0	59.6	59.6	0.0
3	Additions	Line 46	(31.0)	(60.4)	(95.2)	0.0	(82.4)	(82.4)	0.0	127.5	127.5	0.0
4	Interest		(2.8)	(4.0)	(18.5)	(13.1)	(13.2)	(0.1)	(4.0)	(2.1)	1.9	3.5
5	Recovery		4.7	13.8	51.2	272.6	280.6	7.9	229.5	229.5	0.0	0.0
6	End of Year		(53.1)	(103.7)	(485.1)	(225.6)	(300.1)	(74.5)	0.0	114.4	114.4	118.0
Non-Heritage Deferral Account												
7	Beginning of Year		916.8	755.8	463.3	76.1	76.1	0.0	(111.3)	204.7	316.0	(264.9)
8	Adjustment to Opening Balance		(0.1)	0.0	(0.6)	64.8	64.8	0.0	0.0	(354.4)	(354.4)	0.0
9	Transfer to Load Variance					(287.3)	0.0	287.3	0.0	0.0	0.0	0.0
10	Additions	Line 47	(17.2)	(122.0)	(118.4)	0.0	100.1	100.1	0.0	(221.7)	(221.7)	0.0
11	Additions - Waneta 2/3	15.0 L35			(51.9)	(3.1)	(1.3)	1.8	(3.5)	(3.5)	(0.0)	(15.5)
12	Interest		35.7	26.0	12.7	(4.8)	5.9	10.7	(2.1)	(6.9)	(4.8)	(8.4)
13	Recovery		(179.4)	(196.5)	(229.1)	43.0	(40.9)	(83.9)	116.8	116.8	0.0	0.0
14	End of Year		755.8	463.3	76.1	(111.3)	204.7	316.0	(0.0)	(264.9)	(264.9)	(288.8)
Trade Income Deferral Account												
15	Beginning of Year		250.0	194.2	126.8	(258.8)	(258.8)	0.0	(107.9)	(173.7)	(65.8)	(14.3)
16	Adjustment to Opening Balance		(0.0)	0.0	0.0	(1.9)	(1.9)	0.0	0.0	51.9	51.9	0.0
17	Additions	Line 48	(15.1)	(21.4)	(320.5)	0.0	(68.7)	(68.7)	0.0	(0.0)	(0.0)	0.0
18	Interest		8.2	4.5	(2.4)	(6.8)	(8.6)	(1.8)	(1.9)	(2.3)	(0.4)	(0.4)
19	Recovery		(48.9)	(50.5)	(62.7)	159.5	164.2	4.7	109.8	109.8	0.0	0.0
20	End of Year		194.2	126.8	(258.8)	(107.9)	(173.7)	(65.8)	(0.0)	(14.3)	(14.3)	(14.7)
Load Variance												
21	Beginning of Year					0.0	0.0	0.0	214.0	0.0	(214.0)	158.9
22	Adjustment to Opening Balance	Line 9				287.3	0.0	(287.3)	0.0	234.8	234.8	0.0
23	Additions	Line 49				0.0	0.0	0.0	0.0	135.5	135.5	0.0
24	Interest					9.3	0.0	(9.3)	3.9	6.5	2.6	4.9
25	Recovery					(82.7)	0.0	82.7	(217.8)	(217.8)	0.0	0.0
26	End of Year					214.0	0.0	(214.0)	0.0	158.9	158.9	163.8
Biomass Energy Program Variance												
27	Beginning of Year					0.0	0.0	0.0	0.0	0.0	0.0	(8.1)
28	Adjustment to Opening Balance					0.0	0.0	0.0	0.0	(1.1)	(1.1)	0.0
29	Additions - Cost of Energy	Line 50				0.0	0.0	0.0	0.0	(5.1)	(5.1)	0.0
30	Additions - Revenue	Line 51				0.0	0.0	0.0	0.0	(1.7)	(1.7)	0.0
31	Interest					0.0	0.0	0.0	0.0	(0.2)	(0.2)	(0.2)
32	Recovery					0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	End of Year					0.0	0.0	0.0	0.0	(8.1)	(8.1)	(8.3)
End of Year Balances												
34	Heritage	Line 6	(53.1)	(103.7)	(485.1)	(225.6)	(300.1)	(74.5)	0.0	114.4	114.4	118.0
35	Non-Heritage	Line 14	755.8	463.3	76.1	(111.3)	204.7	316.0	(0.0)	(264.9)	(264.9)	(288.8)
36	Trade Income	Line 20	194.2	126.8	(258.8)	(107.9)	(173.7)	(65.8)	(0.0)	(14.3)	(14.3)	(14.7)
37	Load Variance	Line 26	0.0	0.0	0.0	214.0	0.0	(214.0)	0.0	158.9	158.9	163.8
38	Biomass Energy Program Cost	Line 33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.1)	(8.1)	(8.3)
39	Total		896.9	486.5	(667.7)	(230.8)	(269.1)	(38.2)	0.0	(13.9)	(13.9)	(30.1)

BC Hydro
F22 RRADeferral Accounts
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Summary												
40	Deferral Account Additions		(63.3)	(203.7)	(586.0)	(3.1)	(52.2)	(49.1)	(3.5)	30.8	34.3	(15.5)
41	Interest on Deferral Accounts		41.1	26.5	(8.2)	(15.4)	(15.9)	(0.5)	(4.0)	(4.8)	(0.8)	(0.7)
42	Deferral Account Recoveries		(223.7)	(233.2)	(240.6)	392.5	403.9	11.4	238.3	238.3	0.0	0.0
43	Adjustment to Opening Balance	L2+L8+L9+L16+L22+L28	(0.2)	0.0	(319.5)	62.9	62.9	0.0	0.0	(9.2)	(9.2)	0.0
44	Net Transfers		(246.0)	(410.4)	(1,154.2)	436.9	398.6	(38.2)	230.8	255.2	24.3	(16.2)
45	Interest Rate	8.0 L52	3.97%	3.96%	3.99%	3.81%	3.74%	(0.07%)	3.73%	3.37%	(0.36%)	3.09%
Summary of Items Subject to Deferral												
46	Cost of Heritage Energy	4.0 L80	274.3	225.1	221.9	513.3	499.3	(14.0)	219.0	345.6	126.5	392.7
47	Cost of Non-Heritage Energy	4.0 L97	1,254.7	1,287.3	1,364.5	1,321.7	1,426.1	104.4	1,370.7	1,398.2	27.6	1,186.2
48	Trade Income	1.0 L18	(130.2)	(136.6)	(435.7)	(176.3)	(189.2)	(13.0)	(176.3)	(176.2)	0.0	(190.1)
49	Load Variance	14.0 L40				(5,099.7)	(5,079.5)	20.3	(5,036.5)	(4,901.1)	135.5	(5,195.8)
50	Biomass Energy Program Variance - COE	4.0 L98				35.8	31.6	(4.3)	80.7	75.5	(5.1)	102.4
51	Biomass Energy Program Variance - Revenue	14.0 L41				(9.0)	(5.8)	3.2	(15.2)	(16.9)	(1.7)	15.9

BC Hydro
F22 RRAOther Regulatory Accounts
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Demand-Side Management												
1			907.2	915.6	902.5	914.5	914.5	0.0	920.3	906.6	(13.7)	890.1
2			0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3		5.0 L55 - Line 4	97.4	82.3	104.2	90.8	78.5	(12.4)	89.1	82.4	(6.6)	82.2
4			0.0	0.2	7.1	18.3	16.9	(1.4)	9.7	7.6		15.5
5			(89.1)	(95.6)	(99.3)	(103.3)	(103.3)	0.0	(107.4)	(106.5)	0.9	(108.0)
6			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7			915.6	902.5	914.5	920.3	906.6	(13.7)	911.7	890.1	(21.5)	879.9
First Nations Costs												
8			132.8	123.6	104.3	85.0	85.0	0.0	71.4	69.5	(1.9)	54.0
9			0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10		5.0 L56	4.0	2.0	2.3	3.2	2.5	(0.6)	2.4	2.4	(0.1)	2.1
11		Line 19	13.8	12.6	13.7	15.0	12.8	(2.1)	13.1	13.7	0.6	14.7
12			5.4	4.8	4.0	2.9	3.1	0.2	2.3	2.0	(0.3)	1.4
13		5.0 L26	(32.4)	(38.7)	(39.3)	(34.7)	(34.1)	0.6	(33.7)	(33.6)	0.1	(34.4)
14			123.6	104.3	85.0	71.4	69.5	(1.9)	55.5	54.0	(1.6)	37.7
First Nations Settlement Provisions												
15			408.6	408.6	414.2	420.3	420.3	0.0	423.0	426.0	3.0	431.5
16			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17		5.01 L35	(3.3)	0.9	2.4	0.0	0.9	0.9	0.0	1.2	1.2	0.0
18		8.0 L4	17.2	17.2	17.5	17.6	17.6	0.0	18.0	18.0	0.0	18.3
19			(13.8)	(12.6)	(13.7)	(15.0)	(12.8)	2.1	(13.1)	(13.7)	(0.6)	(14.7)
20			408.6	414.2	420.3	423.0	426.0	3.0	427.9	431.5	3.6	435.2
Site C Project												
21			435.6	453.3	472.0	491.3	491.3	0.0	508.4	508.4	0.0	523.6
22			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23		5.0 L57+8.0 L22	0.0	0.3	0.3	(1.7)	(1.5)	0.1	(2.4)	(1.8)	0.6	(7.0)
24			17.7	18.4	19.0	18.7	18.6	(0.1)	18.9	17.1	(1.8)	16.1
25			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26			453.3	472.0	491.3	508.4	508.4	0.0	524.9	523.6	(1.3)	532.8
Future Removal and Site Restoration												
27			(8.6)	2.9	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
28			(0.0)	(2.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29		5.01 L40	2.9					0.0			0.0	
30		7.0 L31	8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31			2.9	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
Foreign Exchange Gains/Losses												
32			(68.6)	(65.5)	(31.3)	11.9	11.9	0.0	9.0	16.6	7.5	13.5
33			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34		8.0 L2	3.4	(4.2)	4.0	(2.3)	5.3	7.5	(1.5)	(3.0)	(1.4)	(2.6)
35		8.0 L26	(0.4)	38.3	39.2	(0.5)	(0.5)	(0.0)	0.5	(0.1)	(0.6)	0.1
36			(65.5)	(31.3)	11.9	9.0	16.6	7.5	8.0	13.5	5.5	11.1

BC Hydro
F22 RRAOther Regulatory Accounts
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Pre-1996 Customer Contributions												
37			92.1	91.4	88.2	83.3	83.3	0.0	78.2	78.2	0.0	73.1
38			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39		7.0 L32	(0.7)	(3.2)	(4.9)	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)
40			91.4	88.2	83.3	78.2	78.2	0.0	73.1	73.1	0.0	67.9
Storm Restoration Costs												
41			29.5	38.6	46.5	58.0	58.0	0.0	29.0	20.8	(8.3)	(12.7)
42			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	(4.0)	(4.0)	0.0
43		5.0 L58 - Line 44	18.6	16.2	18.9	0.0	(7.8)	(7.8)	0.0	0.0	0.0	0.0
44							0.0	0.0		0.0	0.0	0.0
45			1.3	2.1	2.6	1.6	1.1	(0.5)	0.5	0.1	(0.5)	(0.2)
46		5.0 L27	(10.8)	(10.4)	(10.0)	(30.6)	(30.6)	(0.0)	(29.5)	(29.5)	0.0	12.9
47			38.6	46.5	58.0	29.0	20.8	(8.3)	0.0	(12.7)	(12.7)	(0.0)
Capital Project Investigation												
48			25.0	20.1	15.3	10.5	10.5	0.0	5.2	5.2	(0.0)	(0.0)
49			0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50		5.0 L28	(4.8)	(4.8)	(4.8)	(5.2)	(5.2)	(0.0)	(5.2)	(5.2)	0.0	0.0
51			20.1	15.3	10.5	5.2	5.2	(0.0)	0.0	(0.0)	(0.0)	(0.0)
Amortization of Capital Additions												
52			(9.7)	(8.8)	(5.2)	18.4	18.4	0.0	9.2	8.9	(0.4)	(2.1)
53			(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54		7.0 L19	(2.0)	0.7	20.4	0.0	(0.4)	(0.4)	0.0	(1.6)	(1.6)	0.0
55			(0.6)	(0.5)	(0.1)	0.5	0.6	0.1	0.2	0.1	(0.1)	(0.0)
56			3.6	3.4	3.3	(9.7)	(9.7)	0.0	(9.4)	(9.4)	0.0	2.1
57			(8.8)	(5.2)	18.4	9.2	8.9	(0.4)	(0.0)	(2.1)	(2.1)	(0.0)
Total Finance Charges												
58			(305.5)	(215.5)	(139.4)	20.2	20.2	0.0	10.1	11.1	0.9	(74.1)
59			(0.0)	0.0	5.0	0.0	0.0	0.0	0.0	1.6	1.6	0.0
60		8.0 L21	(12.6)	(25.1)	52.8	0.0	0.9	0.9	0.0	(76.6)	(76.6)	0.0
61		8.0 L28+ L30	102.6	101.1	101.8	(10.1)	(10.1)	0.0	(10.1)	(10.1)	0.0	74.1
62			(215.5)	(139.4)	20.2	10.1	11.1	0.9	(0.0)	(74.1)	(74.1)	0.0

BC Hydro
F22 RRAOther Regulatory Accounts
(\$ million)

		Reference	F2017	F2018	F2019	F2020			F2021			F2022
Line	Column		Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Smart Metering & Infrastructure												
63			282.6	260.9	239.2	217.2	217.2	0.0	195.5	195.4	(0.1)	173.0
64			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65		5.0 L59	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66		5.01 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67		15.0 L36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68			11.0	10.1	9.2	7.7	7.8	0.0	6.8	6.1	(0.7)	4.9
69		5.0 L29	(32.6)	(31.8)	(31.1)	(29.4)	(29.6)	(0.2)	(28.5)	(28.5)	0.0	(26.6)
70			260.9	239.2	217.2	195.5	195.4	(0.1)	173.8	173.0	(0.8)	151.4
Home Purchase Option Plan												
71			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
74		5.0 L30	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-Current Pension Cost												
76			690.5	510.7	303.4	485.5	485.5	0.0	364.1	210.1	(154.0)	1,135.7
77			0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	5.4	0.0
78		9.0 L8	(203.2)	(193.6)	173.1	(70.0)	(317.2)	(247.2)	0.0	865.4	865.4	0.0
79			10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
80		5.0 L32	(59.3)	(57.9)	(57.9)	(51.4)	(56.8)	(5.4)	(51.4)	(51.4)	0.0	(114.6)
81		8.0 L27	72.6	70.0	66.8	0.0	98.6	98.6	0.0	106.2	106.2	0.0
82			0.0	(27.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83			0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
84			510.7	303.4	485.5	364.1	210.1	(154.0)	312.7	1,135.7	823.0	1,021.1
Environmental Provisions												
85			380.9	333.2	309.6	278.5	278.5	0.0	236.2	305.1	68.8	344.1
86			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87		5.01 L36	(28.0)	(4.0)	(7.1)	0.0	51.2	51.2	0.0	96.0	96.0	0.0
88		8.0 L5	3.9	4.4	5.9	5.5	4.8	(0.7)	4.8	3.8	(1.0)	3.4
89			(1.6)	(0.7)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
90			(7.9)	(9.0)	(11.0)	(21.7)	(8.2)	13.5	(18.8)	(16.7)	2.1	(22.4)
91		5.01 L17	(14.2)	(14.3)	(18.6)	(26.1)	(21.2)	4.9	(26.0)	(44.0)	(18.0)	(39.1)
92			333.2	309.6	278.5	236.2	305.1	68.8	196.2	344.1	147.9	286.0

BC Hydro
F22 RRAOther Regulatory Accounts
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Rock Bay Remediation												
93			(27.2)	(23.0)	(20.0)	(20.5)	(20.5)	0.0	(10.3)	(10.4)	(0.1)	(0.1)
94			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95		Line 89	1.6	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96			(1.0)	(0.9)	(0.8)	(0.6)	(0.6)	(0.1)	(0.2)	(0.2)	0.0	(0.0)
97		5.01 L20	3.8	3.2	(0.0)	10.8	10.8	0.0	10.4	10.4	0.0	0.1
98			(23.0)	(20.0)	(20.5)	(10.3)	(10.4)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
IFRS PP&E												
99			873.0	961.8	1,025.4	1,064.4	1,064.4	0.0	1,079.2	1,079.2	(0.0)	1,070.6
100			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101		5.0 L60	112.0	89.6	67.2	44.8	44.8	0.0	22.4	22.4	0.0	0.0
102		5.0 L35	(23.2)	(26.0)	(28.2)	(29.9)	(29.9)	(0.0)	(31.0)	(31.0)	0.0	(31.6)
103			961.8	1,025.4	1,064.4	1,079.2	1,079.2	(0.0)	1,070.6	1,070.6	(0.0)	1,039.0
IFRS Pension												
104			611.9	573.6	535.4	497.1	497.1	0.0	458.9	458.9	0.0	420.6
105			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
106		5.0 L36	(38.2)	(38.2)	(38.2)	(38.2)	(38.2)	0.0	(38.2)	(38.2)	0.0	(38.2)
107			573.6	535.4	497.1	458.9	458.9	0.0	420.6	420.6	0.0	382.4
Arrow Water Divestiture Costs												
108			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0
109			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110		Line 118	0.3	1.8	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
111			0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
112		5.01 L21:L22	(0.3)	(1.8)	(3.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
113			0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
Arrow Water Provision												
114			4.6	4.5	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
115			(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
116		5.01 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
117		8.0 L6	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
118		5.01 L22	(0.3)	(1.8)	(3.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
119			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
120			4.5	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Remediation												
121			5.1	(15.8)	(28.6)	(30.8)	(30.8)	0.0	(15.4)	(34.3)	(18.8)	(3.3)
122			(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
123		Line 90	7.9	9.0	11.0	21.7	8.2	(13.5)	18.8	16.7	(2.1)	22.4
124		Line 91	14.2	14.3	18.6	26.1	21.2	(4.9)	26.0	44.0	18.0	39.1
125			(0.2)	(0.7)	(1.2)	(0.9)	(1.3)	(0.4)	(0.3)	(0.6)	(0.3)	(0.1)
126		5.01 L17:L18	(42.7)	(35.4)	(30.6)	(31.6)	(31.6)	0.0	(29.2)	(29.2)	0.0	(58.1)
127			(15.8)	(28.6)	(30.8)	(15.4)	(34.3)	(18.8)	(0.1)	(3.3)	(3.2)	(0.0)

BC Hydro
F22 RRAOther Regulatory Accounts
(\$ million)

million)

		Reference	F2017	F2018	F2019	F2020	F2021	F2022				
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10

BC Hydro
F22 RRAOther Regulatory Accounts
(\$ million)

in million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Customer Crisis Fund												
164			0.0	0.0	0.1	(2.6)	(2.6)	0.0	(2.9)	(5.3)	(2.4)	33.4
165						0.0	0.0	0.0	0.0	0.0	0.0	0.0
166		5.0 L64 - Line167	0.0	0.1	(2.7)	(0.3)	(2.7)	(2.4)	(0.3)	(0.3)	0.0	0.0
167						0.0	0.0	0.0	0.0	1.2	1.2	0.0
168		14.0 L37				0.0	0.0	0.0	0.0	37.3	37.3	0.0
169						0.0	0.0	0.0	(0.1)	0.5	0.6	1.0
170			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
171			0.0	0.1	(2.6)	(2.9)	(5.3)	(2.4)	(3.3)	33.4	36.7	34.5
Mining Customer Payment Plan												
172			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0
173			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
174		5.0 L66	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.0
175		14.0 L38				0.0	0.0	0.0	0.0	6.4	6.4	0.0
176			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2
177			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
178			0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.0	7.2
Project Write-off Costs												
179			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4
180			0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.3	0.0
181		5.01 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
182			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1
183		5.01 L24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(9.3)
184			0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	9.4	0.3
Electric Vehicle Costs												
185			0.0	0.0	0.0	0.0	0.0	0.0	2.3	0.0	(2.3)	4.8
186			0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	2.3	0.0
187		5.0 L65	0.0	0.0	0.0	1.9	0.0	(1.9)	1.7	1.7	0.0	0.0
188		4.0 L61				0.2	0.0	(0.2)	0.3	0.3	0.0	0.0
189		7.0 L20:L21				0.2	0.0	(0.2)	0.5	0.5	0.0	0.0
190			0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	0.1	(0.1)	0.1
191		5.0 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.9)
192			0.0	0.0	0.0	2.3	0.0	(2.3)	4.9	4.8	(0.1)	0.0

BC Hydro
F22 RRAOther Regulatory Accounts
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
End of Year Balances												
193	Demand-Side Management	Line 7	915.6	902.5	914.5	920.3	906.6	(13.7)	911.7	890.1	(21.5)	879.9
194	First Nations Costs	Line 14	123.6	104.3	85.0	71.4	69.5	(1.9)	55.5	54.0	(1.6)	37.7
195	First Nations Settlement Provisions	Line 20	408.6	414.2	420.3	423.0	426.0	3.0	427.9	431.5	3.6	435.2
196	Site C Project	Line 26	453.3	472.0	491.3	508.4	508.4	0.0	524.9	523.6	(1.3)	532.8
197	Future Removal and Site Restoration	Line 31	2.9	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
198	Foreign Exchange Gains/Losses	Line 36	(65.5)	(31.3)	11.9	9.0	16.6	7.5	8.0	13.5	5.5	11.1
199	Pre-1996 Customer Contributions	Line 40	91.4	88.2	83.3	78.2	78.2	0.0	73.1	73.1	0.0	67.9
200	Storm Restoration Costs	Line 47	38.6	46.5	58.0	29.0	20.8	(8.3)	0.0	(12.7)	(12.7)	(0.0)
201	Capital Project Investigation	Line 51	20.1	15.3	10.5	5.2	5.2	(0.0)	0.0	(0.0)	(0.0)	(0.0)
202	Amortization of Capital Additions	Line 57	(8.8)	(5.2)	18.4	9.2	8.9	(0.4)	(0.0)	(2.1)	(2.1)	(0.0)
203	Total Finance Charges	Line 62	(215.5)	(139.4)	20.2	10.1	11.1	0.9	(0.0)	(74.1)	(74.1)	0.0
204	Smart Metering & Infrastructure	Line 70	260.9	239.2	217.2	195.5	195.4	(0.1)	173.8	173.0	(0.8)	151.4
205	Home Purchase Option Plan	Line 75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
206	Non-Current Pension Cost	Line 84	510.7	303.4	485.5	364.1	210.1	(154.0)	312.7	1,135.7	823.0	1,021.1
207	Environmental Provisions	Line 92	333.2	309.6	278.5	236.2	305.1	68.8	196.2	344.1	147.9	286.0
208	Rock Bay Remediation	Line 98	(23.0)	(20.0)	(20.5)	(10.3)	(10.4)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
209	IFRS PP&E	Line 103	961.8	1,025.4	1,064.4	1,079.2	1,079.2	(0.0)	1,070.6	1,070.6	(0.0)	1,039.0
210	IFRS Pension	Line 107	573.6	535.4	497.1	458.9	458.9	0.0	420.6	420.6	0.0	382.4
211	Arrow Water Divestiture Costs	Line 113	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
212	Arrow Water Provision	Line 120	4.5	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
213	Remediation	Line 127	(15.8)	(28.6)	(30.8)	(15.4)	(34.3)	(18.8)	(0.1)	(3.3)	(3.2)	(0.0)
214	Rate Smoothing	Line 132	488.7	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
215	Real Property Sales	Line 138	28.2	37.7	49.2	50.9	56.2	5.3	52.3	47.8	(4.5)	49.2
216	Minimum Reconnection Charge	Line 144	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
217	Debt Management	Line 149	(187.1)	(157.8)	163.2	276.5	952.9	676.4	288.9	1,150.3	861.4	1,141.2
218	Dismantling Cost	Line 155	0.0	35.4	48.3	24.1	16.0	(8.2)	(0.0)	(3.3)	(3.3)	(0.0)
219	PEB Current Pension Costs	Line 163	0.0	3.3	(1.7)	(0.9)	(1.8)	(0.9)	0.0	(6.7)	(6.7)	0.0
220	Customer Crisis Fund	Line 171	0.0	0.1	(2.6)	(2.9)	(5.3)	(2.4)	(3.3)	33.4	36.7	34.5
221	Mining Customer Payment Plan	Line 178	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.0	7.2
222	Project Write-off Costs	Line 184	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	9.4	0.3
223	Electric Vehicle Costs	Line 192	0.0	0.0	0.0	2.3	0.0	(2.3)	4.9	4.8	(0.1)	0.0
224	Total		4,700.1	4,967.8	4,861.1	4,722.1	5,273.1	551.0	4,517.7	6,280.3	1,762.6	6,076.8
Summary												
225	Regulatory Account Additions		46.8	237.7	636.4	279.2	984.2	705.0	144.7	382.7	238.0	112.1
226	Interest on Regulatory Accounts		34.2	35.2	35.7	33.1	32.6	(0.5)	30.1	27.2	(2.9)	25.0
227	Regulatory Account Recoveries		57.0	188.4	(956.9)	(381.4)	(287.7)	93.7	(379.2)	(272.6)	106.6	(340.6)
228	Adjustments to Opening Balances		(0.2)	0.1	5.0	0.1	0.1	(0.0)	0.0	4.5	4.5	0.0
229	OCI Deferral (Pension)		(203.2)	(193.6)	173.1	(70.0)	(317.2)	(247.2)	0.0	865.4	865.4	0.0
230	Regulatory Account Net Transfers		(65.4)	267.7	(106.7)	(139.0)	412.0	551.0	(204.4)	1,007.2	1,211.6	(203.5)
231	Interest Rate	8.0 L52	3.97%	3.96%	3.99%	3.81%	3.74%	(0.07%)	3.73%	3.37%	(0.36%)	3.09%

BC Hydro
F22 RRAReconciliation of Current and Gross Views
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Cost of Energy												
1	Total Gross	4.0 L46	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
2	HDA Additions	4.0 L47	31.0	60.4	95.2	0.0	82.4	82.4	0.0	(127.5)	(127.5)	0.0
3	NHDA Additions	4.0 L48	17.2	122.0	118.4	0.0	(100.1)	(100.1)	0.0	221.7	221.7	0.0
4	Deferred Operating HDA	4.0 L49	(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
5	Deferred Operating NHDA	4.0 L50	(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Deferred Amortization NHDA	4.0 L51	(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
7	Deferred Taxes NHDA	4.0 L52	(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Deferred Provision NHDA	4.0 L53	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	HDA Recoveries	4.0 L54	(4.7)	(13.8)	(51.2)	(272.6)	(280.6)	(7.9)	(229.5)	(229.5)	0.0	0.0
10	NHDA Recoveries	4.0 L55	179.4	196.5	229.1	(43.0)	40.9	83.9	(116.8)	(116.8)	0.0	0.0
11	Load Variance Additions - Revenue	4.0 L56				0.0	0.0	0.0	0.0	(135.5)	(135.5)	0.0
12	Biomass Energy Program Variance Additions - Cost of Energy	4.0 L57				0.0	0.0	0.0	0.0	5.1	5.1	0.0
13	Biomass Energy Program Variance Additions - Revenue	4.0 L58				0.0	0.0	0.0	0.0	1.7	1.7	0.0
14	Customer Crisis Fund Additions - COVID-19 Res. Grants	4.0 L59				0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0
15	Mining Cust. Pay. Plan Additions - COVID-19 SGS Waivers	4.0 L60				0.0	0.0	0.0	0.0	(6.4)	(6.4)	0.0
16	Electric Vehicle Costs Additions - Cost of Energy	4.0 L61				(0.2)	0.0	0.2	(0.3)	(0.3)	0.0	0.0
17	Load Variance Recoveries	4.0 L62				82.7	0.0	(82.7)	217.8	217.8	0.0	0.0
18	Biomass Energy Program Variance Recoveries	4.0 L63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Total Current		1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,670.1
Operating Costs												
20	Total Gross	5.0 L68	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,226.7
21	Deferral Account Additions	5.0 L54	9.0	35.3	0.7	0.0	1.4	1.4	0.0	0.7	0.7	0.0
22	Regulatory Account Additions	5.0 L67	(242.9)	(179.8)	(198.7)	(159.0)	(132.6)	26.4	(125.4)	(112.4)	12.9	(100.2)
23	Subtotal before Recoveries		867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5
24	Regulatory Account Recoveries	5.0 L38	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	230.7
25	Total Current		1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,357.2
Provisions & Other												
26	Total Gross	5.01 L43	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
27	Deferral Account Additions	5.01 L34	0.0	(1.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Regulatory Account Additions	5.01 L42	19.5	(35.4)	(16.0)	0.0	(48.0)	(48.0)	0.0	(102.2)	(102.2)	0.0
29	Subtotal before Recoveries		83.0	115.2	95.9	116.4	128.7	12.4	95.4	95.6	0.2	101.4
30	Regulatory Account Recoveries	5.01 L25	(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
31	Total Current		(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3
Taxes												
32	Total Gross	6.0 L21	223.1	231.1	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
33	Deferral Account Additions	6.0 L22	0.4	1.9	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Total Current		223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
Amortization												
35	Total Gross	7.0 L17	777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
36	Deferral Account Additions	7.0 L14	3.3	14.0	0.0	0.0	(0.4)	(0.4)	0.0	0.2	0.2	0.0
37	Regulatory Account Additions	7.0 L19	2.0	(0.7)	(20.4)	(0.2)	0.4	0.7	(0.5)	1.1	1.6	0.0
38	Subtotal before Recoveries		783.2	821.0	850.9	977.5	977.8	0.3	997.5	998.0	0.5	1,023.7
39	Regulatory Account Recoveries	7.0 L35	77.5	95.4	100.9	118.1	118.1	(0.0)	121.9	121.0	(0.9)	111.1
40	Total Current		860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.7

BC Hydro
F22 RRAReconciliation of Current and Gross Views
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
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			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Finance Charges												
41	Total Gross	8.0 L1	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
42	Total Finance Charge Regulatory Acct. Additions	8.0 L21	12.6	25.1	(52.8)	0.0	(0.9)	(0.9)	0.0	76.6	76.6	0.0
43	Other Regulatory Account Additions	8.0 L3-L8+L22	162.4	(46.9)	(348.5)	(119.8)	(803.1)	(683.3)	(18.6)	(201.8)	(183.2)	(11.9)
44	Interest on Regulatory Accounts	8.0 L25	(75.3)	(61.6)	(27.5)	(17.7)	(16.7)	1.0	(26.0)	(22.3)	3.7	(24.3)
45	Subtotal before Recoveries		678.8	722.5	763.5	737.5	836.1	98.6	698.7	803.9	105.2	519.4
46	Regulatory Account Recoveries	8.0 L31	(174.9)	(209.4)	(207.9)	(1.7)	(100.3)	(98.6)	(2.8)	(108.3)	(105.6)	(65.2)
47	Total Current		504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.2
Return on Equity												
48	Total Gross	9.0 L33	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
49	Subtotal before Recoveries		683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
50	Regulatory Account Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Total Current		683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
Miscellaneous Revenue												
52	Total Gross	15.0 L39	(143.1)	(143.7)	(224.4)	(240.6)	(247.3)	(6.7)	(247.0)	(243.7)	3.3	(255.4)
53	Deferral Account Additions	15.0 L35	0.0	0.0	51.9	3.1	1.3	(1.8)	3.5	3.5	0.0	15.5
54	Regulatory Account Additions	15.0 L38	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Subtotal before Recoveries		(143.4)	(143.7)	(172.5)	(237.5)	(246.0)	(8.5)	(243.6)	(240.2)	3.3	(239.9)
56	Total Current	15.0 L42	(143.4)	(143.7)	(172.5)	(237.5)	(246.0)	(8.5)	(243.6)	(240.2)	3.3	(239.9)
Inter-Segment Revenue												
57	Powerex - Business Support Allocation	3.1 L15	(2.8)	(2.8)	(2.9)	(2.9)	(2.9)	0.0	(2.9)	(2.9)	0.0	(2.9)
58	Mark to Market Losses (Gains)	3.1 L16	(0.2)	(1.0)	1.0	(1.4)	0.8	2.2	0.0	(9.3)	(9.3)	0.0
59	Powerex PTP Charges	3.4 L19	(9.6)	(21.2)	(26.4)	(41.5)	(49.8)	(8.3)	(34.0)	(21.3)	12.6	(34.4)
60	BC Hydro PTP Charges	3.4 L20	(44.3)	(41.3)	(34.3)	(19.1)	(20.1)	(1.0)	(35.0)	(63.8)	(28.8)	(46.3)
61	Total		(56.9)	(66.4)	(62.5)	(64.9)	(72.0)	(7.1)	(71.9)	(97.4)	(25.5)	(83.5)
Powerex Trade Income												
62	Total Gross	1.0 L18	(130.2)	(136.6)	(435.7)	(176.3)	(189.2)	(13.0)	(176.3)	(176.2)	0.0	(190.1)
63	TIDA Additions	2.1 L17	15.1	21.4	320.5	0.0	68.7	68.7	0.0	0.0	0.0	0.0
64	TIDA Recoveries	2.1 L19	48.9	50.5	62.7	(159.5)	(164.2)	(4.7)	(109.8)	(109.8)	0.0	0.0
65	Total Current		(66.2)	(64.7)	(52.4)	(335.8)	(284.8)	51.0	(286.1)	(286.0)	0.0	(190.1)
66	Powerex Net Income	1.0 L19	(2.1)	(3.1)	(3.5)	(3.4)	(3.4)	0.0	(3.7)	0.0	3.7	(2.0)
67	Other Utilities Revenue	14.0 L19	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
68	Liquefied Natural Gas Revenue	14.0 L20	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
69	Deferral Account Rate Rider Revenue	14.0 L23	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
70	Total Rate Revenue Requirement (Current)		4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,211.7

BC Hydro
F22 RRAReconciliation of Current and Gross Views
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Summary - Current Rates View												
71	Cost of Energy	Line 19	1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,670.1
72	Operating Costs	Line 25	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,357.2
73	Provisions & Other	Line 31	(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3
74	Taxes	Line 34	223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
75	Amortization	Line 40	860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.7
76	Finance Charges	Line 47	504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.2
77	Return on Equity	Line 51	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
78	Miscellaneous Revenues	Line 56	(143.4)	(143.7)	(172.5)	(237.5)	(246.0)	(8.5)	(243.6)	(240.2)	3.3	(239.9)
79	Inter-Segment Revenue	Line 61	(56.9)	(66.4)	(62.5)	(64.9)	(72.0)	(7.1)	(71.9)	(97.4)	(25.5)	(83.5)
80	Subsidiary Net Income	L65+L66	(68.4)	(67.7)	(55.9)	(339.2)	(288.2)	51.0	(289.7)	(286.0)	3.7	(192.1)
81	Other Utilities Revenue	Line 67	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
82	Liquefied Natural Gas Revenue	Line 68	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
83	Deferral Account Rate Rider Revenue	Line 69	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
84	Total Rate Revenue Requirement		4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,211.7
Allocation of Current Costs												
85	Generation	3.2 L18	1,408.1	1,371.9	1,513.3	1,695.6	1,757.3	61.7	1,428.9	1,428.2	(0.7)	1,752.6
86	Transmission	3.4 L22	830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	989.7
87	Distribution	3.5 L16	972.4	974.9	965.2	1,209.2	1,204.0	(5.2)	1,218.8	1,204.3	(14.5)	1,207.6
88	Customer Care	3.3 L11	1,567.0	1,787.6	1,820.1	1,607.0	1,458.8	(148.1)	1,760.7	1,595.1	(165.5)	1,484.1
89	Business Support	3.1 L18	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0
90	Subsidiary Net Income	Line 80	(68.4)	(67.7)	(55.9)	(339.2)	(288.2)	51.0	(289.7)	(286.0)	3.7	(192.1)
91	Other Utilities Revenue	Line 81	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
92	Liquefied Natural Gas Revenue	Line 82	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
93	Deferral Account Rate Rider Revenue	Line 83	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
94	Total Rate Revenue Requirement		4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,211.7

BC Hydro
F22 RRATotal Current Costs - Business Support
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	3.6 L6	291.9	378.5	435.8	438.9	462.5	23.6	465.8	471.9	6.1	571.0
2	Current Provisions & Other	(Prior F21: 3.6 L60:L61) 5.01 L31	(204.8)	(310.9)	826.3	1.3	(6.8)	(8.1)	0.6	1.0	0.5	13.2
3	Taxes	6.0 L28	15.7	16.5	17.0	18.2	17.7	(0.5)	18.7	16.1	(2.6)	18.2
4	Current Amortization	7.0 L41	167.0	181.7	166.1	202.8	199.4	(3.4)	202.7	201.2	(1.5)	193.3
5	Business Support Allocation	Line 54 (Prior F19: L59)	(369.9)	(328.7)	(356.2)	(711.8)	(725.4)	(13.6)	(739.9)	(737.1)	2.7	(852.5)
6	Miscellaneous Revenue	15.0 L30	(19.5)	(19.4)	(17.4)	(16.1)	(16.4)	(0.2)	(16.4)	(11.9)	4.5	(15.8)
Internal Allocations												
7	Generation Capitalized Overhead		8.8	7.7	9.4	9.4	9.4	0.0	9.4	9.1	(0.3)	9.7
8	Transmission Capitalized Overhead		16.0	16.9	17.8	16.1	16.1	0.0	16.3	15.6	(0.6)	16.6
9	Distribution Capitalized Overhead		42.1	44.4	43.2	45.5	45.5	0.0	45.7	46.3	0.6	49.2
10	Generation RSRA Write-off	9.0 L43			(500.3)			0.0			0.0	
11	Transmission RSRA Write-off	9.0 L44			(390.9)			0.0			0.0	
12	Distribution RSRA Write-off	9.0 L45			(249.0)			0.0			0.0	
13	Adj to align with prior approved RRA		55.5	17.1				0.0			0.0	
14	Total		122.5	86.1	(1,069.8)	71.0	71.0	0.0	71.4	71.0	(0.3)	75.5
Inter-Segment Revenue												
15	Powerex - Business Support Allocation		(2.8)	(2.8)	(2.9)	(2.9)	(2.9)	0.0	(2.9)	(2.9)	0.0	(2.9)
16	Mark to Market Losses (Gains)		(0.2)	(1.0)	1.0	(1.4)	0.8	2.2	0.0	(9.3)	(9.3)	0.0
17	Total		(3.0)	(3.8)	(1.8)	(4.3)	(2.1)	2.2	(2.9)	(12.2)	(9.3)	(2.9)
18	Total		(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0
Internal Allocation by Function:												
Insurance												
19	Generation		4.2	4.2	4.2	4.3	4.3	0.0	4.3	4.3	0.0	0.0
20	Transmission		2.5	2.5	2.4	2.4	2.4	0.0	2.4	2.4	0.0	0.0
21	Distribution		2.5	2.5	2.6	2.6	2.6	0.0	2.6	2.7	0.1	0.0
22	Customer Care		0.5	0.5	0.5	0.5	0.5	0.0	0.5	0.5	0.0	0.0
23	Total		9.7	9.7	9.7	9.7	9.7	0.0	9.7	9.9	0.2	0.0
Non-Current/Current Pension Costs												
24	Generation		24.2	17.1	28.1	24.5	24.5	0.0	24.9	24.9	(0.0)	0.0
25	Transmission		32.6	23.0	29.7	25.7	25.7	0.0	25.5	26.1	0.6	0.0
26	Distribution		31.7	22.3	28.5	25.9	25.9	0.0	25.7	25.1	(0.6)	0.0
27	Customer Care		6.4	4.5	12.9	10.0	10.0	0.0	10.0	10.0	(0.0)	0.0
28	Total		94.9	66.9	99.2	86.1	86.1	0.0	86.1	86.1	(0.0)	0.0

BC Hydro
F22 RRATotal Current Costs - Business Support
(\$ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
		</										

BC Hydro

F22 RRA

Total Current Costs - Generation
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Cost of Energy	4.0 L65	272.7	238.8	242.8	229.8	293.4	63.7	(16.3)	(24.0)	(7.7)	378.1
2	Current Operating Costs	3.6 L2	195.9	192.6	209.1	206.5	195.2	(11.3)	210.8	220.8	10.0	221.5
3	Current Provisions & Other	(Prior F21: 3.6 L51+L56) 5.01 L27	23.9	24.5	25.1	51.1	55.0	3.9	24.8	24.9	0.2	15.1
4	Taxes	6.0 L24	40.5	40.9	42.5	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1
5	Current Amortization	7.0 L37	276.0	284.8	323.8	353.9	355.6	1.8	363.5	368.1	4.6	375.7
6	Current Finance Charges	8.0 L37	209.5	212.0	243.8	338.4	339.9	1.5	319.6	321.4	1.9	207.8
7	Return on Equity	9.0 L39	284.2	282.6	(187.9)	327.5	325.6	(1.9)	326.9	319.2	(7.8)	325.7
8	Business Support Allocation	3.1 L50	90.9	79.4	86.7	187.8	191.7	3.9	198.5	197.3	(1.2)	228.8
9	Miscellaneous Revenue	(Prior F19: 3.1 L55) 15.0 L3	(2.3)	(1.9)	(2.3)	(1.9)	(2.5)	(0.6)	(1.9)	(1.7)	0.2	(2.2)
Internal Allocations												
10	GRTA Allocation	3.4 L9	43.3	43.3	43.3	43.3	43.3	0.0	43.3	43.3	0.0	43.3
11	Generation Real Time Dispatch	3.4 L10	1.6	1.6	1.6	2.4	2.4	0.0	2.4	2.4	(0.0)	3.1
12	Generation Ancillary Services	3.4 L14	(2.0)	(2.7)	(6.0)	(2.8)	(2.1)	0.8	(2.8)	(2.8)	0.0	(2.5)
13	Generation Capitalized Overhead	3.1 L7	(8.8)	(7.7)	(9.4)	(9.4)	(9.4)	0.0	(9.4)	(9.1)	0.3	(9.7)
14	Generation RSRA Write-off	3.1 L10	0.0	0.0	500.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Waneta 2/3 Lease revenue from Teck	3.3 L8	0.0	0.0	0.0	(75.2)	(75.2)	(0.0)	(76.7)	(76.7)	(0.0)	(78.2)
16	Adj to align with prior approved RRA		(17.2)	(16.0)				0.0			0.0	
17	Total		16.9	18.4	529.7	(41.8)	(41.0)	0.8	(43.3)	(42.9)	0.3	(44.0)
18	Total		1,408.1	1,371.9	1,513.3	1,695.6	1,757.3	61.7	1,428.9	1,428.2	(0.7)	1,752.6

BC Hydro
F22 RRATotal Current Costs - Customer Care
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Cost of Energy	4.0 L67	1,443.0	1,615.4	1,666.5	1,405.0	1,259.0	(145.9)	1,554.0	1,400.0	(154.0)	1,292.0
2	Current Operating Costs	3.6 L5	(0.4)	(4.0)	127.9	78.7	75.0	(3.7)	79.6	67.6	(12.0)	69.7
3	Current Provisions & Other	5.01 L30 (Prior F21: 3.6 L54+L59)	0.4	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Taxes	6.0 L27	2.6	4.2	2.6	0.6	0.9	0.3	0.6	0.8	0.2	0.8
5	Current Amortization	7.0 L40	17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
6	Business Support Allocation	3.1 L53	22.8	20.5	35.9	73.0	74.6	1.6	76.2	75.7	(0.5)	66.9
7	Miscellaneous Revenue	15.0 L25 (Prior F19: 3.1 L58)	(24.9)	(23.4)	(35.6)	(114.5)	(114.8)	(0.3)	(116.4)	(115.7)	0.8	(114.1)
Internal Allocations												
8	Waneta 2/3 Lease revenue from Teck	15.0 L20				75.2	75.2	0.0	76.7	76.7	0.0	78.2
9	Adj to align with prior approved RRA		106.4	141.5				0.0			0.0	
10	Total		106.4	141.5	0.0	75.2	75.2	0.0	76.7	76.7	0.0	78.2
11	Total		1,567.0	1,787.6	1,820.1	1,607.0	1,458.8	(148.1)	1,760.7	1,595.1	(165.5)	1,484.1

BC Hydro

F22 RRA

Total Current Costs - Transmission
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	3.6 L3	403.7	398.2	228.0	219.4	206.4	(13.1)	220.5	226.2	5.7	245.5
2	Current Provisions & Other	(Prior F21: 3.6 L52+L57) 5.01 L28	47.2	56.8	34.4	33.8	48.7	14.9	37.3	37.8	0.5	62.8
3	Taxes	6.0 L25	137.9	143.8	152.3	157.6	158.4	0.8	163.7	163.1	(0.6)	167.0
4	Current Amortization	7.0 L38	215.7	225.8	229.0	233.5	234.4	0.8	236.1	233.9	(2.2)	239.2
5	Current Finance Charges	8.0 L38	178.7	182.5	190.5	243.9	243.0	(0.9)	227.6	226.8	(0.8)	148.3
6	Return on Equity	9.0 L40	242.4	243.2	(146.8)	236.1	232.8	(3.2)	232.9	225.2	(7.7)	232.5
7	Business Support Allocation	3.1 L51	117.7	102.6	100.3	203.3	207.2	3.9	209.9	207.0	(3.0)	248.6
8	Miscellaneous Revenue	(Prior F19: 3.1 L56) 15.0 L10	(44.1)	(43.3)	(57.6)	(46.1)	(46.4)	(0.3)	(46.8)	(46.8)	0.1	(39.2)
Internal Allocations:												
9	GRTA Allocation		(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	0.0	(43.3)	(43.3)	0.0	(43.3)
10	Generation Real Time Dispatch		(1.6)	(1.6)	(1.6)	(2.4)	(2.4)	(0.0)	(2.4)	(2.4)	0.0	(3.1)
11	Distribution Real Time Dispatch		(16.7)	(16.4)	(16.7)	(20.6)	(20.8)	(0.2)	(21.0)	(20.9)	0.1	(26.3)
12	SDA Allocation to Distribution		(125.6)	(127.6)	(126.6)	(125.6)	(127.0)	(1.4)	(127.4)	(145.8)	(18.3)	(150.4)
13	PTP Allocation to Distribution	L21 + L68	(26.7)	(28.3)	(35.7)	(43.6)	(23.9)	19.7	(36.0)	(0.0)	35.9	2.8
14	Generation Ancillary Services		2.0	2.7	6.0	2.8	2.1	(0.8)	2.8	2.8	0.0	2.5
15	Transmission Capitalized Overhead	3.1 L8	(16.0)	(16.9)	(17.8)	(16.1)	(16.1)	0.0	(16.3)	(15.6)	0.6	(16.6)
16	Transmission RSRA Write-off	3.1 L11	0.0	0.0	390.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Adj to align with prior approved RRA		(186.9)	(187.0)				0.0			0.0	
18	Total		(414.8)	(418.2)	155.3	(248.7)	(231.3)	17.4	(243.5)	(225.2)	18.3	(234.4)
Inter-Segment Revenue												
19	Powerex PTP Charges		(9.6)	(21.2)	(26.4)	(41.5)	(49.8)	(8.3)	(34.0)	(21.3)	12.6	(34.4)
20	BC Hydro PTP Charges		(44.3)	(41.3)	(34.3)	(19.1)	(20.1)	(1.0)	(35.0)	(63.8)	(28.8)	(46.3)
21	Total		(53.9)	(62.6)	(60.7)	(60.6)	(69.9)	(9.3)	(69.0)	(85.1)	(16.1)	(80.6)
22	Total Current Costs		830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	989.7
Transmission Revenue Requirement												
23	Total Current Costs	Line 22	830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	989.7
24	Adj to offset re-org impact							0.0			0.0	
25	Adj. Total Current Costs		830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	989.7
26	PTP Allocation to Distribution	Line 13	26.7	28.3	35.7	43.6	23.9	(19.7)	36.0	0.0	(35.9)	(2.8)
27	Inter-Segment Revenue	Line 21	53.9	62.6	60.7	60.6	69.9	9.3	69.0	85.1	16.1	80.6
28	External OATT Revenue	Line 74	11.8	11.4	15.4	15.9	10.7	(5.2)	15.9	12.9	(3.0)	11.1
29	Total TRR		923.0	931.1	936.4	1,092.3	1,087.7	(4.7)	1,089.6	1,061.0	(28.6)	1,078.6

BC Hydro

F22 RRA

Total Current Costs - Transmission
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
NITS Charge to BC Hydro												
30	Adj. Total Current Costs	Line 25				972.2			968.8	962.9		989.7
31	Internal Ancillary Services	Line 36				0.0			0.0	0.0		0.0
32	Internal Scheduling & Dispatch	Line 38				(3.8)			(3.9)	(3.8)		(3.8)
33	Total		820.1	826.2	813.0	968.4	928.2	(40.2)	964.8	959.1	(5.7)	985.9
34	NITS Monthly Rate	Line 33 / 12	68.3	68.9	67.8	80.7	77.4		80.4	79.9		82.2
Long-Term PTP Rate												
35	Total TRR	Line 29				1,092.3			1,089.6	1,061.0		1,078.6
36	Internal Ancillary Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	External Ancillary Services		(2.0)	(2.7)	(6.0)	(2.8)	(2.1)	0.8	(2.8)	(2.8)	0.0	(2.5)
38	Internal Scheduling & Dispatch		(2.7)	(2.6)	(3.0)	(3.8)	(3.5)	0.4	(3.9)	(3.8)	0.1	(3.8)
39	External Scheduling & Dispatch		(0.2)	(0.1)	(0.2)	(0.2)	(0.1)	0.1	(0.2)	(0.2)	(0.0)	(0.2)
40	Total					1,085.4			1,082.7	1,054.1		1,072.2
41	Maximum Supply (MW)		12,978	13,124	13,171	13,279	13,279		13,279	13,279		13,596
42	Long-Term Firm PTP Rate (\$/MW/year)		70,687	70,451	70,702	81,741	78,490		81,531	79,383		78,862
Maximum Price for Short-Term Firm and Non-Firm (per MW of Reserved Capacity)												
43	Monthly (\$/MW/month)		5,890.60	5,870.95	5,891.87	6,811.71	6,540.80		6,794.28	6,615.27		6,571.79
44	Weekly (\$/MW/week)		1,359.37	1,354.83	1,359.66	1,571.93	1,509.42		1,567.91	1,526.60		1,516.57
45	Daily (\$/MW/day)		193.66	193.02	193.71	223.95	215.04		223.37	217.49		216.06
46	Hourly (\$/MW/hour)		8.07	8.04	8.07	9.33	8.96		9.31	9.06		9.00
Scheduling Fee												
47	Scheduling, Control & Dispatch	L38 + L39	2.9	2.7	3.1	4.1	3.6		4.1	4.0		4.0
48	Total Volume (GWh)		25,664	27,707	29,543	29,388	27,093		29,773	26,589		25,496
49	Scheduling Fee (\$/MWh)	L47 / L48	0.113	0.099	0.106	0.138	0.133		0.139	0.152		0.155
Long-Term PTP Volumes (GWh)												
50	Internal		8,226	8,448	8,609	8,567	9,242	675	8,567	8,338	(230)	7,577
51	External		1,130	908	876	1,314	878	(436)	1,314	949	(365)	876
52	Total		9,356	9,356	9,485	9,881	10,121	239	9,881	9,287	(595)	8,453
Long-Term PTP Revenue												
53	Internal	L46 * L50	65.9	68.0	69.6	79.9	82.8	2.9	79.8	75.5	(4.2)	68.2
54	External	L46 * L51	9.1	7.3	6.9	12.3	7.9	(4.4)	12.2	8.6	(3.6)	7.9
55	Total		74.9	75.2	76.6	92.2	90.7	(1.5)	92.0	84.1	(7.9)	76.1
Long-Term PTP Average Price (\$/MWh)												
56	Internal	L53 / L50	8.01	8.05	8.09	9.33	8.96	(0.37)	9.31	9.06	(0.25)	9.00
57	External	L54 / L51	8.01	8.02	7.89	9.33	8.96	(0.37)	9.31	9.06	(0.25)	9.00
58	Total	L55 / L52	8.01	8.04	8.07	9.33	8.96	(0.37)	9.31	9.06	(0.25)	9.00

BC Hydro

F22 RRA

Total Current Costs - Transmission
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Short-Term PTP Volumes (GWh)												
59	Internal		6,608	8,338	7,093	9,700	3,848	(5,852)	10,085	3,848	(6,237)	3,848
60	External		288	446	657	240	170	(70)	240	500	260	240
61	Total		6,897	8,785	7,750	9,940	4,017	(5,923)	10,325	4,348	(5,977)	4,088
Short-Term PTP Revenue												
62	Internal		14.8	22.9	26.7	24.2	11.0	(13.3)	25.2	9.6	(15.6)	9.6
63	External		0.6	1.2	2.3	0.6	0.6	(0.0)	0.6	1.3	0.7	0.6
64	Total		15.4	24.2	29.1	24.8	11.5	(13.3)	25.8	10.9	(14.9)	10.2
Short-Term PTP Average Price (\$/MWh)												
65	Internal	L62 / L59	2.24	2.75	3.77	2.50	2.85	0.35	2.50	2.50	0.00	2.50
66	External	L63 / L60	2.24	2.75	3.52	2.50	3.46	0.96	2.50	2.50	0.00	2.50
67	Total	L64 / L61	2.24	2.75	3.75	2.50	2.87	0.37	2.50	2.50	0.00	2.50
Total PTP Revenue												
68	Internal	L53 + L62	80.7	90.9	96.4	104.2	93.8	(10.4)	105.0	85.2	(19.8)	77.8
69	External	L54 + L63	9.7	8.5	9.2	12.9	8.5	(4.4)	12.8	9.8	(3.0)	8.5
70	Total		90.4	99.4	105.6	117.0	102.2	(14.8)	117.8	95.0	(22.8)	86.3
Total External OATT Revenue												
71	Total External PTP	Line 69	9.7	8.5	9.2	12.9	8.5	(4.4)	12.8	9.8	(3.0)	8.5
72	External Ancillary Services	Line 37	2.0	2.7	6.0	2.8	2.1	(0.8)	2.8	2.8	0.0	2.5
73	External Scheduling & Dispatch	Line 39	0.2	0.1	0.2	0.2	0.1	(0.1)	0.2	0.2	0.0	0.2
74	Total		11.8	11.4	15.4	15.9	10.7	(5.2)	15.9	12.9	(3.0)	11.1

BC Hydro

F22 RRA

Total Current Costs - Distribution
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020		Diff	F2021		Diff	F2022
			Actual	Actual	Actual	RRA	Actual		RRA	Forecast		Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	3.6 L4	178.8	184.5	181.7	252.2	268.5	16.3	250.0	266.8	16.8	249.6
2	Current Provisions & Other	(Prior F21: 3.6 L53+L58) 5.01 L29	54.2	48.5	58.6	76.4	78.0	1.6	76.1	75.1	(0.9)	74.2
3	Taxes	6.0 L26	26.8	27.5	28.3	29.1	28.6	(0.6)	32.9	29.5	(3.3)	31.7
4	Current Amortization	7.0 L39	184.9	194.7	210.1	216.5	217.6	1.1	227.0	225.8	(1.2)	235.9
5	Current Finance Charges	8.0 L39	115.7	118.7	121.3	153.4	152.8	(0.6)	148.8	147.4	(1.4)	98.1
6	Return on Equity	9.0 L41	157.0	158.2	(93.5)	148.4	146.4	(2.0)	152.2	146.3	(5.9)	153.8
7	Business Support Allocation	3.1 L52	138.6	126.2	133.3	247.7	251.9	4.2	255.3	257.2	1.9	308.2
8	Miscellaneous Revenue	(Prior F19: 3.1 L57) 15.0 L13	(52.7)	(55.7)	(59.5)	(58.9)	(66.0)	(7.1)	(62.0)	(64.2)	(2.2)	(68.6)
Internal Allocations												
9	Distribution Real Time Dispatch	3.4 L11	16.7	16.4	16.7	20.6	20.8	0.2	21.0	20.9	(0.1)	26.3
10	SDA Allocation from Transmission	3.4 L12	125.6	127.6	126.6	125.6	127.0	1.4	127.4	145.8	18.3	150.4
11	PTP Allocation to Distribution	3.4 L13	26.7	28.3	35.7	43.6	23.9	(19.7)	36.0	0.0	(35.9)	(2.8)
12	Distribution Capitalized Overhead	3.1 L9	(42.1)	(44.4)	(43.2)	(45.5)	(45.5)	0.0	(45.7)	(46.3)	(0.6)	(49.2)
13	Distribution RSRA Write-off	3.1 L12	0.0	0.0	249.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Adj to align with prior approved RRA		42.1	44.4				0.0			0.0	
15	Total		169.0	172.2	384.8	144.3	126.2	(18.1)	138.7	120.4	(18.3)	124.7
16	Total		972.4	974.9	965.2	1,209.2	1,204.0	(5.2)	1,218.8	1,204.3	(14.5)	1,207.6

BC Hydro

F22 RRA

Total Current Operating Costs and Provisions
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Total Current Operating Costs	5.0 L51	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,357.2
	Total Internal Allocation											
2	Generation		(205.4)	(204.4)	(202.6)	(213.4)	(207.5)	5.9	(216.8)	(220.8)	(4.0)	(221.5)
3	Transmission		(208.7)	(212.3)	(216.5)	(220.7)	(221.1)	(0.4)	(221.8)	(226.2)	(4.3)	(245.5)
4	Distribution		(202.7)	(206.7)	(219.3)	(253.2)	(260.4)	(7.2)	(251.5)	(266.8)	(15.2)	(249.6)
5	Customer Care		(100.0)	(134.8)	(120.7)	(69.8)	(67.4)	2.4	(70.4)	(67.6)	2.8	(69.7)
6	Business Support		(353.2)	(391.7)	(423.3)	(438.8)	(451.2)	(12.5)	(466.1)	(471.9)	(5.8)	(571.0)
7	Total		(1,069.9)	(1,149.8)	(1,182.5)	(1,195.8)	(1,207.6)	(11.8)	(1,226.7)	(1,253.2)	(26.5)	(1,357.2)
8	Total		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total Internal Allocation by BG											
	Integrated Planning											
9	Generation	3.7 L2	(107.2)	(105.6)	(99.0)	(102.0)	(98.1)	3.9	(103.4)	(103.5)	(0.1)	(110.2)
10	Transmission	3.7 L3	(114.5)	(111.7)	(115.7)	(118.5)	(118.4)	0.1	(120.0)	(120.0)	0.0	(137.4)
11	Distribution	3.7 L4	(63.0)	(66.0)	(74.1)	(73.5)	(76.8)	(3.3)	(72.9)	(77.4)	(4.5)	(99.1)
12	Customer Care	3.7 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Business Support	3.7 L6	(3.2)	(3.3)	(3.7)	(4.4)	(4.5)	(0.1)	(4.8)	(5.8)	(1.1)	(5.6)
14	Total	3.7 L7	(287.9)	(286.6)	(292.5)	(298.4)	(297.8)	0.6	(301.1)	(306.7)	(5.6)	(352.2)
	Capital Infrastructure Project Delivery											
15	Generation	3.8 L2	(47.1)	(50.2)	(52.3)	(53.2)	(52.5)	0.6	(54.4)	(54.2)	0.2	(49.4)
16	Transmission	3.8 L3	(31.7)	(35.6)	(36.3)	(32.0)	(31.6)	0.5	(30.8)	(30.5)	0.3	(33.4)
17	Distribution	3.8 L4	(5.6)	(5.3)	(5.7)	(5.6)	(5.5)	0.1	(5.4)	(5.4)	0.0	(6.1)
18	Customer Care	3.8 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Business Support	3.8 L6	(32.1)	(32.4)	(35.8)	(29.2)	(29.8)	(0.6)	(29.4)	(29.7)	(0.3)	(29.8)
20	Total	3.8 L7	(116.5)	(123.4)	(130.1)	(120.0)	(119.5)	0.5	(120.0)	(119.8)	0.2	(118.7)
	Operations											
21	Generation	3.9 L2	(51.2)	(48.7)	(51.3)	(58.3)	(56.9)	1.4	(59.0)	(63.1)	(4.1)	(61.9)
22	Transmission	3.9 L3	(62.4)	(64.9)	(64.5)	(69.3)	(70.3)	(1.0)	(70.2)	(74.9)	(4.7)	(73.6)
23	Distribution	3.9 L4	(101.5)	(103.6)	(108.4)	(144.6)	(148.4)	(3.8)	(144.7)	(155.5)	(10.8)	(112.9)
24	Customer Care	3.9 L5	(1.4)	(1.9)	(2.7)	(1.4)	(1.9)	(0.5)	(1.4)	0.0	1.4	0.0
25	Business Support	3.9 L6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Total	3.9 L7	(216.5)	(219.1)	(226.9)	(273.6)	(277.5)	(3.9)	(275.3)	(293.5)	(18.1)	(248.5)
	Safety											
27	Generation	3.10 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Transmission	3.10 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Distribution	3.10 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Customer Care	3.10 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Business Support	3.10 L6	(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)
32	Total	3.10 L7	(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)

BC Hydro
F22 RRAIntegrated Planning
Current Operating Costs and Provisions (\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	5.0 L40	287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	352.2
	Internal Allocations											
2	Generation	Line 15	(107.2)	(105.6)	(99.0)	(102.0)	(98.1)	3.9	(103.4)	(103.5)	(0.1)	(110.2)
3	Transmission	Line 23	(114.5)	(111.7)	(115.7)	(118.5)	(118.4)	0.1	(120.0)	(120.0)	0.0	(137.4)
4	Distribution	Line 31	(63.0)	(66.0)	(74.1)	(73.5)	(76.8)	(3.3)	(72.9)	(77.4)	(4.5)	(99.1)
5	Customer Care							0.0			0.0	
6	Business Support	Line 34	(3.2)	(3.3)	(3.7)	(4.4)	(4.5)	(0.1)	(4.8)	(5.8)	(1.1)	(5.6)
7	Total		(287.9)	(286.6)	(292.5)	(298.4)	(297.8)	0.6	(301.1)	(306.7)	(5.6)	(352.2)
8	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Generation											
9	Energy Planning & Analytics		0.7	0.7	0.8	1.0	1.0	0.0	1.0	1.2	0.2	1.1
10	Dam Safety	5.1 L2	8.4	8.6	9.7	10.2	9.8	(0.4)	10.3	10.9	0.5	11.4
11	Stations Asset Planning		75.0	78.7	71.8	70.7	69.7	(1.0)	71.5	66.8	(4.7)	74.7
12	Engineering Design		6.7	7.0	7.4	7.9	7.7	(0.2)	8.0	7.6	(0.4)	7.5
13	Engineering Services		1.5	1.7	2.1	2.7	2.6	(0.1)	2.8	3.3	0.6	4.4
14	Business Support		14.9	8.8	7.1	9.5	7.2	(2.2)	9.9	13.7	3.8	11.2
15	Subtotal		107.2	105.6	99.0	102.0	98.1	(3.9)	103.4	103.5	0.1	110.2
	Transmission											
16	Energy Planning & Analytics		0.9	0.9	1.1	1.3	1.3	0.0	1.3	1.6	0.3	1.3
17	Stations Asset Planning		27.5	28.8	26.3	25.9	25.5	(0.4)	26.2	24.4	(1.7)	27.8
18	Line Asset Planning		53.6	57.2	64.1	63.1	65.2	2.1	63.7	66.4	2.7	83.9
19	Interconnections and Shared Assets		5.0	4.3	5.2	5.1	6.4	1.3	5.2	6.4	1.2	5.5
20	Engineering Design		7.4	7.8	8.3	8.8	8.6	(0.2)	8.9	8.5	(0.4)	8.4
21	Engineering Services		1.3	1.5	1.9	2.4	2.3	(0.1)	2.4	2.9	0.5	3.8
22	Business Support		18.8	11.1	8.9	11.9	9.1	(2.8)	12.3	9.7	(2.6)	6.7
23	Subtotal		114.5	111.7	115.7	118.5	118.4	(0.1)	120.0	120.0	(0.0)	137.4
	Distribution											
24	Energy Planning & Analytics		0.9	1.0	1.1	1.3	1.3	0.0	1.3	1.6	0.3	1.4
25	Stations Asset Planning		0.4	0.4	0.4	0.4	0.4	(0.0)	0.4	0.4	(0.0)	0.7
26	Line Asset Planning		53.8	57.5	64.4	63.4	65.5	2.1	64.0	66.7	2.7	84.3
27	Interconnections and Shared Assets		5.2	4.5	5.5	5.3	6.7	1.3	5.4	6.7	1.3	5.8
28	Engineering Design		2.1	2.2	2.3	2.4	2.4	(0.1)	2.5	2.4	(0.1)	2.3
29	Engineering Services		0.3	0.3	0.4	0.5	0.5	(0.0)	0.5	0.6	0.1	0.7
30	Business Support		0.2	0.1	0.1	0.1	0.1	(0.0)	(1.2)	(1.0)	0.3	3.8
31	Subtotal		63.0	66.0	74.1	73.5	76.8	3.3	72.9	77.4	4.5	99.1
	Business Support											
32	Energy Planning & Analytics		3.2	3.3	3.7	4.4	4.5	0.1	4.8	5.8	1.1	5.3
33	Business Unit Support		0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.3
34	Subtotal		3.2	3.3	3.7	4.4	4.5	0.1	4.8	5.8	1.1	5.6

BC Hydro
F22 RRACapital Infrastructure Project Delivery
Current Operating Costs and Provisions (\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	5.0 L41	116.5	123.4	130.1	120.0	119.5	(0.5)	120.0	119.8	(0.2)	118.7
	Internal Allocations											
2	Generation	Line 16	(47.1)	(50.2)	(52.3)	(53.2)	(52.5)	0.6	(54.4)	(54.2)	0.2	(49.4)
3	Transmission	Line 23	(31.7)	(35.6)	(36.3)	(32.0)	(31.6)	0.5	(30.8)	(30.5)	0.3	(33.4)
4	Distribution	Line 29	(5.6)	(5.3)	(5.7)	(5.6)	(5.5)	0.1	(5.4)	(5.4)	0.0	(6.1)
5	Customer Care							0.0			0.0	
6	Business Support	Line 34	(32.1)	(32.4)	(35.8)	(29.2)	(29.8)	(0.6)	(29.4)	(29.7)	(0.3)	(29.8)
7	Total		(116.5)	(123.4)	(130.1)	(120.0)	(119.5)	0.5	(120.0)	(119.8)	0.2	(118.7)
8	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Generation											
9	Project Delivery		5.4	5.8	5.7	6.0	5.9	(0.0)	7.5	7.2	(0.3)	6.6
10	Indigenous Relations		2.0	1.7	1.9	1.7	1.7	(0.0)	1.8	1.7	(0.0)	1.9
11	Environment		20.8	21.4	23.0	23.6	23.3	(0.3)	23.7	23.9	0.1	24.3
12	Properties		0.7	0.7	0.8	0.7	0.7	0.0	0.7	0.7	0.0	0.7
13	Business Unit Support		0.3	0.3	0.3	0.3	0.3	(0.0)	0.4	0.3	(0.0)	0.5
	Regulatory Account Recoveries											
	- Operating Costs											
14	First Nation Costs		13.0	15.5	15.7	15.6	15.3	(0.3)	15.2	15.1	(0.0)	15.5
15	Capital Project Investigation	5.0 L28	4.8	4.8	4.8	5.2	5.2	0.0	5.2	5.2	0.0	0.0
16	Subtotal		47.1	50.2	52.3	53.2	52.5	(0.6)	54.4	54.2	(0.2)	49.4
	Transmission											
17	Project Delivery		7.0	7.4	7.3	7.6	7.6	(0.1)	6.9	6.6	(0.3)	8.4
18	Indigenous Relations		2.5	2.1	2.3	2.1	2.1	(0.0)	2.1	2.1	(0.0)	2.3
19	Environment		2.6	2.7	2.9	2.9	2.9	(0.0)	3.0	3.0	0.0	3.4
20	Properties		0.2	0.2	0.2	0.1	0.1	0.0	0.1	0.1	0.0	0.2
21	Business Unit Support		0.1	0.1	0.1	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.3
	Regulatory Account Recoveries											
	- Operating Costs											
22	First Nation Costs		19.5	23.2	23.6	19.1	18.7	(0.4)	18.5	18.5	(0.1)	18.9
23	Subtotal		31.7	35.6	36.3	32.0	31.6	(0.5)	30.8	30.5	(0.3)	33.4
	Distribution											
24	Project Delivery		0.3	0.4	0.4	0.4	0.4	(0.0)	0.1	0.1	(0.0)	0.4
25	Indigenous Relations		2.3	2.0	2.2	2.0	1.9	(0.0)	2.0	2.0	(0.0)	2.2
26	Environment		2.8	2.9	3.1	3.1	3.1	(0.0)	3.2	3.2	0.0	3.3
27	Properties		0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.0
28	Business Unit Support		0.1	0.0	0.1	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.2
29	Subtotal		5.6	5.3	5.7	5.6	5.5	(0.1)	5.4	5.4	(0.0)	6.1
	Business Support											
30	Indigenous Relations		0.4	0.4	0.4	0.4	0.4	(0.0)	0.4	0.4	(0.0)	0.4
31	Environment		0.1	0.1	0.1	0.1	0.1	(0.0)	0.1	0.1	0.0	0.0
32	Properties		31.3	31.7	35.0	28.4	29.1	0.6	28.6	28.9	0.3	29.4
33	Business Unit Support		0.3	0.2	0.3	0.3	0.3	(0.0)	0.3	0.3	(0.0)	0.0
34	Subtotal		32.1	32.4	35.8	29.2	29.8	0.6	29.4	29.7	0.3	29.8

BC Hydro
F22 RRA

Operations

Current Operating Costs and Provisions (\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020		F2021			F2022	
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	5.0 L42	216.5	219.1	226.9	273.6	277.5	3.9	275.3	293.5	18.1	248.5
	Internal Allocations											
2	Generation	Line 16	(51.2)	(48.7)	(51.3)	(58.3)	(56.9)	1.4	(59.0)	(63.1)	(4.1)	(61.9)
3	Transmission	Line 23	(62.4)	(64.9)	(64.5)	(69.3)	(70.3)	(1.0)	(70.2)	(74.9)	(4.7)	(73.6)
4	Distribution	Line 31	(101.5)	(103.6)	(108.4)	(144.6)	(148.4)	(3.8)	(144.7)	(155.5)	(10.8)	(112.9)
5	Customer Care	Line 33	(1.4)	(1.9)	(2.7)	(1.4)	(1.9)	(0.5)	(1.4)	0.0	1.4	0.0
6	Business Support							0.0			0.0	
7	Total		(216.5)	(219.1)	(226.9)	(273.6)	(277.5)	(3.9)	(275.3)	(293.5)	(18.1)	(248.5)
8	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Generation											
9	Program and Contract Management		0.2	0.2	0.2	0.2	0.3	0.0	0.2	0.3	0.0	0.3
10	Line Field Operations		0.1	0.1	0.1	0.2	0.2	0.0	0.2	0.2	0.0	0.2
11	Stations Field Operations		27.3	25.9	28.7	34.8	33.7	(1.1)	35.2	39.6	4.4	37.1
12	Construction Services		2.3	2.5	2.5	2.7	2.7	0.0	2.7	3.4	0.7	3.0
13	Generation System Operations	5.3 L6	20.5	19.1	18.8	19.7	19.2	(0.5)	20.0	18.8	(1.2)	19.8
14	T&D System Operations		0.4	0.4	0.4	0.4	0.4	0.0	0.4	0.4	(0.0)	0.6
15	Business Unit Support		0.3	0.5	0.6	0.3	0.5	0.1	0.3	0.5	0.2	0.8
16	Subtotal		51.2	48.7	51.3	58.3	56.9	(1.4)	59.0	63.1	4.1	61.9
	Transmission											
17	Program and Contract Management		2.9	2.9	3.0	3.5	4.0	0.5	3.5	4.0	0.5	4.2
18	Line Field Operations		4.7	4.9	4.9	5.9	6.0	0.1	6.0	6.4	0.4	6.3
19	Stations Field Operations		9.5	9.0	9.9	12.0	11.7	(0.4)	12.2	13.7	1.5	12.1
20	Construction Services		7.1	7.8	7.7	8.3	8.3	0.0	8.4	10.5	2.1	9.3
21	T&D System Operations		37.9	40.0	38.3	39.4	40.0	0.6	39.9	39.8	(0.1)	41.0
22	Business Unit Support		0.3	0.4	0.6	0.3	0.4	0.1	0.3	0.5	0.2	0.8
23	Subtotal		62.4	64.9	64.5	69.3	70.3	1.0	70.2	74.9	4.7	73.6
	Distribution											
24	Program and Contract Management		8.6	8.8	9.1	10.3	11.9	1.6	10.5	12.0	1.5	12.8
25	Line Field Operations		64.5	66.2	65.9	79.8	80.8	1.0	80.5	86.3	5.8	85.8
26	Stations Field Operations		4.8	4.5	5.0	6.1	5.9	(0.2)	6.1	6.8	0.8	6.6
27	Distribution Design & Customer Connect	5.3 L4	10.2	10.6	14.9	14.8	15.9	1.1	15.1	16.9	1.8	16.4
28	Construction Services		2.0	2.1	2.1	2.3	2.3	0.0	2.3	2.9	0.6	2.6
29	Business Unit Support		0.7	0.9	1.3	0.7	0.9	0.2	0.7	1.1	0.4	1.7
	Regulatory Account Recoveries											
	- Operating Costs											
30	Storm Restoration	5.0 L27	10.8	10.4	10.0	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)
31	Subtotal		101.5	103.6	108.4	144.6	148.4	3.8	144.7	155.5	10.8	112.9
	Customer Care											
32	Business Unit Support (incl. Waneta 2/3)		1.4	1.9	2.7	1.4	1.9	0.5	1.4	0.0	(1.4)	0.0
33	Subtotal		1.4	1.9	2.7	1.4	1.9	0.5	1.4	0.0	(1.4)	0.0

BC Hydro

F22 RRA

Safety

Current Operating Costs and Provisions (\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	5.0 L43	56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
	Internal Allocations											
2	Generation							0.0			0.0	
3	Transmission							0.0			0.0	
4	Distribution							0.0			0.0	
5	Customer Care							0.0			0.0	
6	Business Support	Line 15	(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)
7	Total		(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)
8	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Business Support											
9	Safety System and Assurance	5.4 L1	14.5	14.7	12.1	13.1	12.4	(0.7)	13.3	13.3	0.0	13.3
10	Learning and Development	5.4 L2	25.7	23.2	23.8	25.8	23.2	(2.6)	26.2	25.8	(0.4)	26.3
11	Field Safety Services	5.4 L3	5.7	5.7	6.6	6.6	6.4	(0.1)	6.7	6.9	0.3	7.4
12	Security and Emergency Management	5.4 L4	9.4	9.2	10.5	10.7	12.3	1.6	10.8	19.4	8.6	12.5
13		5.4 L5	0.7	0.9	0.8	1.0	1.4	0.4	1.0	3.7	2.7	8.1
14	Business Unit Support	5.4 L6	0.6	0.6	0.6	0.6	0.6	(0.0)	0.6	0.6	(0.0)	0.8
15	Subtotal		56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3

BC Hydro

F22 RRA

Finance, Technology, Supply Chain

Current Operating Costs and Provisions (\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	5.0 L44	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
	Internal Allocations											
2	Generation							0.0			0.0	
3	Transmission	Line 10	0.0	0.0	0.0	(0.8)	(0.8)	0.0	(0.8)	(0.8)	0.0	(1.0)
4	Distribution							0.0			0.0	
5	Customer Care							0.0			0.0	
6	Business Support	Line 15	(253.8)	(246.7)	(261.2)	(261.8)	(264.2)	(2.5)	(263.9)	(280.6)	(16.6)	(298.1)
7	Total		(253.8)	(246.7)	(261.2)	(262.6)	(265.1)	(2.5)	(264.8)	(281.4)	(16.6)	(299.1)
8	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Transmission											
9	Technology - MODS costs		0.0	0.0	0.0	0.8	0.8	0.0	0.8	0.8	(0.0)	1.0
10	Subtotal		0.0	0.0	0.0	0.8	0.8	0.0	0.8	0.8	(0.0)	1.0
	Business Support											
11	Finance	5.5 L1	28.7	28.7	29.4	31.6	31.6	0.0	32.1	45.8	13.7	51.0
12	Technology (excl. MODS costs)	5.5 L2- Line 9	134.5	128.3	137.1	134.9	137.6	2.6	135.5	138.1	2.5	145.3
13	Supply Chain	5.5 L3	89.9	89.0	94.0	94.5	94.3	(0.2)	95.5	95.9	0.4	101.0
14	Business Unit Support	5.5 L4	0.7	0.7	0.8	0.8	0.8	(0.0)	0.8	0.8	0.0	0.9
15	Subtotal		253.8	246.7	261.2	261.8	264.2	2.5	263.9	280.6	16.6	298.1

BC Hydro

F22 RRA

People, Customer, Corporate Affairs

Current Operating Costs and Provisions (\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	5.0 L45	142.6	142.9	135.6	139.0	138.7	(0.3)	139.1	145.9	6.8	153.7
	Internal Allocations											
2	Generation							0.0			0.0	
3	Transmission							0.0			0.0	
4	Distribution	Line 11	(32.6)	(31.8)	(31.1)	(29.4)	(29.6)	(0.2)	(28.5)	(28.5)	0.0	(31.5)
5	Customer Care	Line 15	(69.5)	(69.2)	(63.6)	(68.3)	(65.5)	2.9	(69.0)	(67.6)	1.4	(69.7)
6	Business Support	Line 21	(40.4)	(41.8)	(40.9)	(41.2)	(43.6)	(2.4)	(41.7)	(49.9)	(8.2)	(52.6)
7	Total		(142.6)	(142.9)	(135.6)	(139.0)	(138.7)	0.3	(139.1)	(145.9)	(6.8)	(153.7)
8	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Distribution											
	Regulatory Account Recoveries											
	- Operating Costs											
9	Smart Metering & Infrastructure	5.0 L29	32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	26.6
10	EV Charging Infrastructure	5.0 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
11	Subtotal		32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	31.5
	Customer Care											
12	Customer Services	5.6 L2	68.9	68.7	59.0	62.4	60.5	(1.9)	63.0	61.8	(1.2)	68.6
13	Conservation and Energy Management	5.6 L3	0.6	0.5	0.5	0.6	0.6	(0.0)	0.6	0.4	(0.2)	0.7
14	Customer Crisis Fund	5.6 L12	0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	(0.0)	0.5
15	Subtotal		69.5	69.2	63.6	68.3	65.5	(2.9)	69.0	67.6	(1.4)	69.7
	Business Support											
16	Human Resources	5.6 L1	21.6	22.1	20.1	21.1	21.0	(0.1)	21.4	21.5	0.1	23.2
17	Communications and Community Engagement	5.6 L4	12.4	13.7	13.7	12.9	12.7	(0.2)	13.0	13.6	0.6	14.2
18	Regulatory and Rates	5.6 L5	5.1	4.5	5.5	5.4	8.1	2.8	5.4	12.8	7.4	13.1
19	Ethics and Merit Office	5.6 L6	0.5	0.6	0.8	1.0	1.0	(0.0)	1.0	1.1	0.1	1.1
20	Business Unit Support	5.6 L7	0.8	0.7	0.7	0.8	0.7	(0.1)	0.8	0.8	0.0	0.9
21	Subtotal		40.4	41.8	40.9	41.2	43.6	2.4	41.7	49.9	8.2	52.6

BC Hydro
F22 RRAOther
Current Operating Costs and Provisions (\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	Current Operating Costs	5.0 L46	(63.3)	9.0	18.0	(6.1)	(3.2)	2.9	17.3	(14.2)	(31.5)	8.7
2	Non-Current PEB - Pension	5.0 L47	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
3	PEB Current Pension Costs	5.0 L48	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
4	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	5.0 L49	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	F17-F19 RRA Compliance Filing Adjustment	5.0 L50	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Subtotal		59.3	67.9	63.6	50.5	55.9	8.3	50.5	50.5	(31.5)	107.9
7	Total		(4.0)	76.9	81.6	44.4	52.7	8.3	67.8	36.3	(31.5)	116.6
Internal Allocations												
8	Generation							0.0			0.0	
9	Transmission							0.0			0.0	
10	Distribution							0.0			0.0	
11	Customer Care	Line 18	(29.0)	(63.6)	(54.4)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
12	Business Support	Line 30	33.0	(13.3)	(27.2)	(44.4)	(52.7)	(8.3)	(67.8)	(36.3)	31.5	(116.6)
13	Total		4.0	(76.9)	(81.6)	(44.4)	(52.7)	(8.3)	(67.8)	(36.3)	31.5	(116.6)
14	Total		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Allocation by Function:												
Customer Care												
15	Independent Power Producer Capital Leases	5.7 L8	28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory Account Recoveries												
- Operating Costs												
16	Home Purchase Offer Plan	5.0 L30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Minimum Reconnection Charge	5.0 L31	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Subtotal		29.0	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Business Support												
19	Office of the General Counsel	5.7 L1	11.1	10.6	11.1	11.7	12.0	0.3	11.8	13.4	1.6	13.0
20	President and Chief Operating Officer	5.7 L2	1.0	0.8	0.9	0.9	0.8	(0.0)	0.9	0.8	(0.0)	0.9
21	Corporate Costs	5.7 L4	13.1	28.4	22.3	28.9	32.7	3.8	29.1	(4.3)	(33.5)	0.5
22	Capitalized Costs	5.7 L5	(281.8)	(283.9)	(284.8)	(285.8)	(287.0)	(1.2)	(286.2)	(285.9)	0.3	(290.4)
23	IFRS Ineligible Capitalized Costs	5.7 L7	102.9	125.3	147.7	170.1	170.1	0.0	192.5	192.5	0.0	214.9
Regulatory Account Recoveries												
- Operating Costs												
24	IFRS PP&E	5.0 L35	23.2	26.0	28.2	29.9	29.9	0.0	31.0	31.0	0.0	31.6
25	IFRS Pension	5.0 L36	38.2	38.2	38.2	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2
26	Non-Current PEB - Pension	5.0 L47	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
27	PEB Current Pension Costs	5.0 L48	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
28	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	5.0 L49	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	F17-F19 RRA Compliance Filing Adjustment	5.0 L50	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Subtotal		(33.0)	13.3	27.2	44.4	52.7	8.3	67.8	36.3	(31.5)	116.6

BC Hydro
F22 RRA

Cost of Energy

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Sources of Supply (GWh)												
Heritage Energy												
1	Water Rentals		48,736	47,926	42,341	39,368	40,383	1,015	44,522	47,920	3,398	46,563
2	Natural Gas for Thermal Generation		74	91	191	181	171	(10)	195	175	(20)	222
3	Exchange Net		(253)	599	(155)	(473)	(581)	(108)	(250)	(316)	(66)	(211)
4	Total		48,557	48,616	42,377	39,075	39,972	897	44,467	47,779	3,312	46,574
Non-Heritage Energy												
5	IPPs and Long-Term Commitments		13,644	14,354	14,248	13,949	14,475	526	15,238	14,467	(771)	15,980
6	Non-Integrated Area		118	115	103	118	106	(11)	120	107	(13)	109
7	Total		13,762	14,469	14,351	14,067	14,581	514	15,358	14,574	(784)	16,089
Market Energy												
8	Market Electricity Purchases		131	150	2,035	3,633	3,471	(162)	1,326	0	(1,326)	0
9	Surplus Sales		(5,756)	(5,072)	(2,230)	(84)	(182)	(98)	(3,515)	0	3,515	0
10	System Imports									1,485	1,485	1,956
11	System Exports									(8,521)	(8,521)	(6,796)
12	Net Purchases (Sales) from Powerex		138	(557)	647	468	(940)	(1,407)	(279)	0	279	0
13	Total		(5,488)	(5,479)	452	4,017	2,349	(1,667)	(2,467)	(7,036)	(4,569)	(4,840)
14	Total Sources of Supply	L4+L7+L13	56,832	57,606	57,181	57,159	56,903	(256)	57,357	55,316	(2,041)	57,823
15	Less Line Loss and System Use		(4,937)	(5,504)	(4,768)	(5,200)	(4,972)	228	(5,416)	(4,857)	560	(5,376)
16	Total Domestic Sales	14.0 L11	51,895	52,102	52,413	51,958	51,931	(27)	51,940	50,459	(1,481)	52,448
17	Line Loss as % of Sales		9.51%	10.56%	9.10%	10.01%	9.57%	(0.43%)	10.43%	9.62%	(0.80%)	10.25%
Unit Costs (\$/MWh)												
18	Water Rentals		7.9	7.5	8.6	8.4	8.2	(0.2)	7.3	6.9	(0.4)	8.1
19	Natural Gas for Thermal Generation		128.9	37.7	40.0	41.8	41.7	(0.1)	43.7	46.9	3.2	53.1
20	IPPs and Long-Term Commitments		88.9	91.4	87.5	92.8	90.8	(2.0)	92.6	96.0	3.4	92.3
21	Non-Integrated Area		211.8	231.0	281.0	259.1	293.8	34.7	250.7	244.1	(6.6)	251.2
22	Market Electricity Purchases		25.8	24.4	61.4	41.5	38.4	(3.1)	32.9	0.0	(32.9)	0.0
23	Surplus Sales		(23.1)	(27.5)	(51.6)	(5.0)	(5.5)	(0.5)	(47.0)	0.0	47.0	0.0
24	System Imports									25.5	25.5	39.4
25	System Exports									24.8	24.8	43.6
26	Total Weighted Cost		29.0	29.5	29.0	35.9	34.9	(1.1)	32.1	31.4	(0.7)	31.8
Cost of Energy (\$ million)												
Heritage Energy												
27	Water Rentals		387.0	361.6	363.1	329.3	331.6	2.3	323.2	331.0	7.8	375.4
28	Natural Gas for Thermal Generation		9.5	3.4	7.6	7.5	7.1	(0.4)	8.5	8.2	(0.3)	11.8
29	Domestic Transmission - Other		22.5	22.5	22.3	24.5	24.8	0.3	24.4	25.7	1.3	25.5
30	Non-Treaty Storage and Libby Coordination Agreements		(23.3)	(40.6)	(181.9)	15.0	37.7	22.7	(11.7)	(34.2)	(22.4)	(19.0)
31	Remissions and Other		(41.3)	(38.0)	(33.9)	(25.2)	(42.4)	(17.2)	(26.7)	(42.1)	(15.5)	(43.2)
32	Total		354.4	309.0	177.2	351.2	358.8	7.7	317.7	288.6	(29.1)	350.6

BC Hydro
F22 RRA

Cost of Energy

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Non-Heritage Energy												
33			1,213.1	1,311.6	1,247.2	1,294.7	1,314.0	19.3	1,410.8	1,388.7	(22.1)	1,475.7
34			25.0	26.5	28.9	30.5	31.3	0.7	30.2	26.1	(4.1)	27.4
35			11.7	13.1	9.4	3.7	4.5	0.8	2.5	5.2	2.6	4.9
36		15.0 L22	0.0	0.0	2.4	3.5	3.3	(0.2)	3.7	3.2	(0.5)	3.5
37			1,249.7	1,351.1	1,287.9	1,332.4	1,353.1	20.7	1,447.2	1,423.1	(24.0)	1,511.5
Market Energy												
38			3.4	3.7	125.0	150.6	133.1	(17.4)	43.7	0.0	(43.7)	0.0
39			(132.8)	(139.4)	(115.0)	(0.4)	(1.0)	(0.6)	(165.1)	0.0	165.1	0.0
40										37.8	37.8	77.1
41										(211.0)	(211.0)	(296.5)
42			2.3	(10.9)	25.0	33.1	(35.2)	(68.3)	6.1	0.0	(6.1)	0.0
43			28.3	25.2	18.5	1.1	2.0	0.9	17.0	45.1	28.1	27.5
44			(98.7)	(121.5)	53.5	184.4	99.0	(85.4)	(98.4)	(128.1)	(29.7)	(191.9)
45		L32+L37+L44	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
Current Cost of Energy												
46		Line 45	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
47		2.1 L3	31.0	60.4	95.2	0.0	82.4	82.4	0.0	(127.5)	(127.5)	0.0
48		2.1 L10+L11	17.2	122.0	118.4	0.0	(100.1)	(100.1)	0.0	221.7	221.7	0.0
49		Line 78	(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
50		Line 91	(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51		Line 92	(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
52		Line 93	(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53		Line 94	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54		2.1 L5	(4.7)	(13.8)	(51.2)	(272.6)	(280.6)	(7.9)	(229.5)	(229.5)	0.0	0.0
55		2.1 L13	179.4	196.5	229.1	(43.0)	40.9	83.9	(116.8)	(116.8)	0.0	0.0
56		2.1 L23				0.0	0.0	0.0	0.0	(135.5)	(135.5)	0.0
57		2.1 L29				0.0	0.0	0.0	0.0	5.1	5.1	0.0
58		2.1 L30				0.0	0.0	0.0	0.0	1.7	1.7	0.0
59		2.2 L168				0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0
60		2.2 L175				0.0	0.0	0.0	0.0	(6.4)	(6.4)	0.0
61						(0.2)	0.0	0.2	(0.3)	(0.3)	0.0	0.0
62		2.1 L25				82.7	0.0	(82.7)	217.8	217.8	0.0	0.0
63		2.1 L32				0.0	0.0	0.0	0.0	0.0	0.0	0.0
64			1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,670.1
Total Current COE by Function												
65			272.7	238.8	242.8	229.8	293.4	63.7	(16.3)	(24.0)	(7.7)	378.1
66			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67			1,443.0	1,615.4	1,666.5	1,405.0	1,259.0	(145.9)	1,554.0	1,400.0	(154.0)	1,292.0
68			1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,670.1

BC Hydro
F22 RRA

Cost of Energy

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Items Subject to HDA												
69	Heritage Energy	Line 32	354.4	309.0	177.2	351.2	358.8	7.7	317.7	288.6	(29.1)	350.6
70	Less: F15-F19 Water Rentals (Waneta 1/3)		(7.0)	(6.5)	(6.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Market Electricity Purchases	Line 38	3.4	3.7	125.0	150.6	133.1	(17.4)	43.7	0.0	(43.7)	0.0
72	Surplus Sales	Line 39	(132.8)	(139.4)	(115.0)	(0.4)	(1.0)	(0.6)	(165.1)	0.0	165.1	0.0
73	Electric Vehicle Costs Additions	Line 61	0.0	0.0	0.0	(0.2)	0.0	0.2	(0.3)	(0.3)	0.0	0.0
74	Domestic Transmission - Export	Line 43	28.3	25.2	18.5	1.1	2.0	0.9	17.0	45.1	28.1	27.5
75	Costs in Operating/Amortization		12.2	12.2	12.2	12.5	12.5	0.0	12.5	11.9	(0.7)	12.5
76	Notional Water Rentals		0.8	(3.7)	4.1	3.1	(6.1)	(9.2)	(1.8)	0.0	1.8	0.0
77	Skagit and Ancillary Revenue	14.0 L19 / L39	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
78	Deferred Operating HDA	5.0 L52	(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
79	Other		27.9	36.3	36.2	31.5	31.0	(0.5)	31.2	31.2	0.0	32.3
80	Total		274.3	225.1	221.9	513.3	499.3	(14.0)	219.0	345.6	126.5	392.7
81	Total System Inflow (% of Average)		101%	98%	87%	87%	93%	6%	100%	108%	8%	100%
Items Subject to NHDA												
82	Non-Heritage Cost of Energy	Line 37	1,249.7	1,351.1	1,287.9	1,332.4	1,353.1	20.7	1,447.2	1,423.1	(24.0)	1,511.5
83	Add: F15-F19 Water Rentals (Waneta 1/3)	Line 70	7.0	6.5	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
84	Less: Water Rentals (Waneta 2/3)	Line 36	0.0	0.0	(2.4)	(3.5)	(3.3)	0.2	(3.7)	(3.2)	0.5	(3.5)
85	Net Purchases (Sales) from Powerex	Line 42	2.3	(10.9)	25.0	33.1	(35.2)	(68.3)	6.1	0.0	(6.1)	0.0
86	System Imports	Line 40								37.8	37.8	77.1
87	System Exports	Line 41								(211.0)	(211.0)	(296.5)
88	Commodity Risk		(0.2)	(1.0)	1.0	(1.4)	0.8	2.2	0.0	(9.3)	(9.3)	0.0
89	Notional Water Rental	Line 76	(0.8)	3.7	(4.1)	(3.1)	6.1	9.2	1.8	0.0	(1.8)	0.0
90	Revenue Variance		1.3	(13.5)	50.7	0.0	139.3	139.3	0.0	249.0	249.0	0.0
91	Deferred Operating NHDA	5.0 L53	(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
92	Deferred Amortization NHDA	7.0 L14	(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
93	Deferred Taxes NHDA	6.0 L20	(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94	Deferred Provision NHDA	5.01 L34	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95	Other		7.9	1.2	0.3	0.0	(3.6)	(3.6)	0.0	(12.5)	(12.5)	0.0
96	Less: IPP subject to Biomass Energy Program Variance					(35.8)	(31.6)	4.3	(80.7)	(75.5)	5.1	(102.4)
97	Total		1,254.7	1,287.3	1,364.5	1,321.7	1,426.1	104.4	1,370.7	1,398.2	27.6	1,186.2
98	Biomass Energy Program Cost Def. Acct.					35.8	31.6	(4.3)	80.7	75.5	(5.1)	102.4
IPP Summary												
99	IPP Costs in Non-Heritage COE	Line 33	1,213.1	1,311.6	1,247.2	1,294.7	1,314.0	19.3	1,410.8	1,388.7	(22.1)	1,475.7
	Existing Capital Leases											
100	Operating Costs	5.7 L8	28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101	Taxes	6.0 L10	2.6	4.2	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
102	Amortization	7.0 L11	17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
103	Finance Charges	8.0 L15	25.1	44.7	42.4	48.4	48.4	0.0	46.1	46.1	0.0	43.5
104	Total		72.9	141.8	122.1	137.4	137.4	0.0	136.1	136.1	0.0	134.1
105	Transfers to Deferral & Regulatory Accounts		(18.4)	(79.4)	(0.5)	0.0	0.4	0.4	0.0	0.1	0.1	0.0
106	Total Costs in Revenue Requirement		1,267.6	1,374.0	1,368.9	1,432.1	1,451.8	19.7	1,546.9	1,524.9	(22.1)	1,609.7
107	Total Payments to IPPs		1,274.7	1,381.7	1,354.9	1,416.6	1,430.9	14.3	1,533.1	1,492.9	(40.2)	1,601.3
108	Difference	L106 - L107	(7.2)	(7.6)	13.9	15.5	20.9	5.4	13.9	32.0	18.2	8.5

BC Hydro
F22 RRA

Cost of Energy

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
IPP Capital Leases												
Gross Assets in Service												
109		Opening Balance	388.2	388.2	694.7	694.7	694.7	0.0	1,751.5	1,978.6	227.1	1,978.6
110		Capital Additions	0.0	470.0	0.0	1,751.5	1,978.6	227.1	0.0	0.0	0.0	0.0
111		Retirements & Transfers	0.0	(163.5)	0.0	(694.7)	(694.7)	0.0	0.0	0.0	0.0	0.0
112		Closing Balance	388.2	694.7	694.7	1,751.5	1,978.6	227.1	1,751.5	1,978.6	227.1	1,978.6
Accumulated Amortization												
113		Opening Balance	186.9	200.6	54.1	77.0	77.0	0.0	592.9	613.0	20.1	702.9
114		Adjustment to Opening Balance	0.0	0.0	0.0	427.0	523.7	96.8	0.0	0.0	0.0	0.0
115		Amortization	13.7	15.4	22.9	88.9	89.3	0.4	90.1	89.9	(0.2)	90.6
116		Retirements & Transfers	0.0	(161.8)	0.0	0.0	(77.0)	(77.0)	0.0	0.0	0.0	0.0
117		Closing Balance	200.6	54.1	77.0	592.9	613.0	20.1	683.0	702.9	19.9	793.5
118		Net Capital Leases (Year-End)	187.6	640.6	617.7	1,158.6	1,365.6	207.0	1,068.5	1,275.7	207.2	1,185.1

BC Hydro
F22 RRAOperating Costs - Total Company
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by Business Group												
1		5.1 L9	287.9	286.6	288.8	292.7	292.5	(0.3)	295.2	300.8	5.6	346.2
2		5.2 L6	79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3
3		5.3 L9	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4
4		5.4 L7	56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
5		5.5 L5	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
6		5.6 L8	110.0	111.0	100.4	104.2	104.7	0.4	105.4	112.1	6.8	121.8
7		5.7 L6	(256.6)	(244.0)	(250.5)	(244.3)	(241.4)	2.9	(244.4)	(275.9)	(31.5)	(276.0)
8			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9			736.6	743.1	757.2	796.1	804.2	8.1	806.4	833.0	26.6	905.1
Base Operating Costs												
10			102.9	125.3	147.7	170.1	170.1	0.0	192.5	192.5	0.0	214.9
11			28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12			0.0	0.0	3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
13			0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	(0.0)	0.5
14			131.0	188.8	209.8	181.1	179.8	(1.2)	203.6	203.6	(0.0)	221.4
15		L9+L14	867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5
Operating Costs by Resource												
16			487.8	522.2	544.8	592.2	601.1	8.9	602.5	603.2	0.8	652.5
17			48.1	41.9	3.6	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
18			419.3	434.2	456.8	425.0	412.4	(12.7)	423.6	423.6	0.0	475.1
19			47.9	48.2	52.9	46.3	54.3	8.0	46.3	49.0	2.7	49.5
20			67.4	67.2	73.4	51.4	62.7	11.3	51.5	52.1	0.6	51.5
21			(179.0)	(158.6)	(137.1)	(115.8)	(116.9)	(1.1)	(93.8)	(95.6)	(1.9)	(75.5)
22			(23.9)	(23.1)	(27.3)	(22.1)	(29.6)	(7.5)	(20.1)	(22.3)	(2.2)	(26.6)
23		Line 8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24								0.0		26.6	26.6	
25			867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5
Regulatory Account Recoveries - Operating Costs												
26			32.4	38.7	39.3	34.7	34.1	(0.6)	33.7	33.6	(0.1)	34.4
27			10.8	10.4	10.0	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)
28			4.8	4.8	4.8	5.2	5.2	0.0	5.2	5.2	0.0	0.0
29			32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	26.6
30			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31			0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32			59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
33			0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
34			0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35			23.2	26.0	28.2	29.9	29.9	0.0	31.0	31.0	0.0	31.6
36			38.2	38.2	38.2	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2
37			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
38			202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	230.7
39		L15+L38	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,357.2

BC Hydro
F22 RRAOperating Costs - Total Company
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Current Operating Costs by Business Group												
40	Integrated Planning	L1+L12	287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	352.2
41	Capital Infrastructure Project Delivery	L2+L26+L28	116.5	123.4	130.1	120.0	119.5	(0.5)	120.0	119.8	(0.2)	118.7
42	Operations	L3+L27	216.5	219.1	226.9	273.6	277.5	3.9	275.3	293.5	18.1	248.5
43	Safety	Line 4	56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
44	Finance, Technology, Supply Chain	Line 5	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
45	People, Customer, Corporate Affairs	L6+L13+L29+L37	142.6	142.9	135.6	139.0	138.7	(0.3)	139.1	145.9	6.8	153.7
46	Other	L7+L10+L11+L30+L31+L35+L36	(63.3)	9.0	18.0	(6.1)	(3.2)	2.9	17.3	(14.2)	(31.5)	8.7
47	Non-Current PEB - Pension	Line 32	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
48	PEB Current Pension Costs	Line 33	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
49	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	Line 34	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	F17-F19 RRA Compliance Filing Adjustment	Line 8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Total		1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,357.2
Deferral Account Additions												
52	Transfers to HDA		(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
53	Transfers to NHDA		(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Total		(9.0)	(35.3)	(0.7)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
Regulatory Account Additions												
55	Demand-Side Management		97.4	82.5	111.3	109.1	95.4	(13.7)	98.8	90.0	(8.7)	97.8
56	First Nations Costs		4.0	2.0	2.3	3.2	2.5	(0.6)	2.4	2.4	(0.1)	2.1
57	Site C Project		0.0	0.3	0.3	0.3	0.3	0.0	0.3	0.3	(0.0)	0.3
58	Storm Restoration		18.6	16.2	18.9	0.0	(7.8)	(7.8)	0.0	0.0	0.0	0.0
59	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	IFRS Capitalized Overhead		112.0	89.6	67.2	44.8	44.8	0.0	22.4	22.4	0.0	0.0
61	PEB Current Pension Costs		10.1	(2.5)	0.7	0.0	(0.9)	(0.9)	0.0	(5.8)	(5.8)	0.0
62	PEB CPC - F17-F19 RRA Compliance Filing Adjustment		0.0	(10.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Real Property Sales		0.8	1.6	0.6	0.0	0.9	0.9	0.0	0.0	0.0	0.0
64	Customer Crisis Fund		0.0	0.1	(2.7)	(0.3)	(2.7)	(2.4)	(0.3)	0.9	1.2	0.0
65	Electric Vehicle Costs		0.0	0.0	0.0	1.9	0.0	(1.9)	1.7	1.7	0.0	0.0
66	Mining Customer Payment Plan		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.0
67	Total		242.9	179.8	198.7	159.0	132.6	(26.4)	125.4	112.4	(12.9)	100.2
68	Total Gross Operating Costs	L15+L54+L67	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,226.7

BC Hydro
F22 RRA

Operating Costs - Total Company
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs Continuity											
69	Base Operating Costs	Line 9	736.6	743.1	757.2	796.1	804.2	8.1	806.4	833.0	26.6	905.1
70	Base Operating Costs Adjustments	Line 14	131.0	188.8	209.8	181.1	179.8	(1.2)	203.6	203.6	(0.0)	221.4
71	Net Operating Costs	Line 15	867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5
72	Deferral Account Additions and Regulatory Account Additions	L54 + L67	233.9	144.5	198.0	159.0	131.2	(27.8)	125.4	111.8	(13.6)	100.2
73	Gross Operating Costs	Line 68	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,226.7
74	Reverse Deferral Account Additions and Regulatory Account Additions	Line 72	(233.9)	(144.5)	(198.0)	(159.0)	(131.2)	27.8	(125.4)	(111.8)	13.6	(100.2)
75	Regulatory Account Recoveries	Line 38	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	230.7
76	Current Operating Costs	Line 39	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,357.2

BC Hydro
F22 RRAProvisions & Other - Total Company
(\$ million)

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Provisions & Other - By Business Groups												
1	Integrated Planning		72.6	82.6	74.7	67.2	89.5	22.3	71.5	71.1	(0.4)	75.9
2	Capital Infrastructure Project Delivery		(9.0)	(3.9)	(5.4)	1.5	(7.8)	(9.3)	0.3	0.3	0.0	0.1
3	Operations		6.4	15.9	9.7	36.1	33.1	(3.0)	12.3	12.4	0.2	13.4
4	Safety		0.0	0.3	0.7	0.0	6.3	6.3	0.0	0.0	0.0	0.0
5	Finance, Technology, Supply Chain		7.8	7.8	3.9	0.2	4.2	4.0	0.2	0.2	0.0	0.2
6	People, Customer, Corporate Affairs		0.1	0.0	1.2	0.0	0.1	0.1	0.0	0.0	0.0	0.0
7	Other		5.0	12.5	11.2	11.5	3.5	(8.0)	11.2	11.7	0.5	11.9
8	Total		83.0	115.2	95.9	116.4	128.7	12.4	95.4	95.6	0.2	101.4
Provisions & Other - By Category												
9	Gain/loss on Capital and Intangible Assets		61.8	69.4	60.7	43.9	47.0	3.2	46.8	46.7	(0.0)	50.0
	Gain/Loss on Project Write-offs		0.0	0.0	0.0	0.0	15.3	15.3	0.0	0.0	0.0	0.0
10	Real Property Sales		(10.0)	(10.0)	(10.0)	0.0	(10.0)	(10.0)	0.0	0.0	0.0	0.0
11	Bank Fees and Other Charges		5.1	5.3	5.5	5.5	6.0	0.5	5.6	5.9	0.3	6.0
12	Dismantling Expenses		30.9	35.7	30.6	67.0	67.0	0.0	43.0	43.0	(0.0)	45.5
13	EPA Terminations		0.4	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Other Provisions		(5.1)	10.8	7.0	0.0	3.4	3.4	0.0	0.0	0.0	0.0
15	First Nations Provisions		0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Total		83.0	115.2	95.9	116.4	128.7	12.4	95.4	95.6	0.2	101.4
Regulatory Account Recoveries												
17	PCB Remediation		18.3	18.9	15.3	22.5	22.5	(0.0)	22.7	22.7	0.0	53.1
18	Asbestos Remediation		24.4	16.6	15.3	9.1	9.1	(0.0)	6.4	6.4	0.0	5.0
19	Dismantling Cost		0.0	0.0	0.0	25.5	25.5	(0.0)	24.6	24.6	0.0	(3.3)
20	Rock Bay Remediation		(3.8)	(3.2)	0.0	(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)
21	Arrow Water Divestiture Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Arrow Water Provision		0.3	1.8	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Rate Smoothing		(201.2)	(326.2)	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Project Write-Off Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3
25	Total		(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
26	Total Current Provisions & Other	L16 + L25	(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3
Current Provisions & Other By Function												
27	Generation		23.9	24.5	25.1	51.1	55.0	3.9	24.8	24.9	0.2	15.1
28	Transmission		47.2	56.8	34.4	33.8	48.7	14.9	37.3	37.8	0.5	62.8
29	Distribution		54.2	48.5	58.6	76.4	78.0	1.6	76.1	75.1	(0.9)	74.2
30	Customer Care		0.4	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Business Unit Support		(204.8)	(310.9)	826.3	1.3	(6.8)	(8.1)	0.6	1.0	0.5	13.2
32	Total		(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3

BC Hydro
F22 RRAProvisions & Other - Total Company
(\$ million)

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10

Operating Costs and Provisions - Total Company - Supplemental Schedule
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Operating Costs Including Regulatory												
1	Labour (excl Non-Current PEB)	L114 + L124	524.9	537.2	573.2	617.0	623.0	6.0	627.2	623.0	(4.3)	679.0
2	Services - ABSU	L115 + L125	48.9	42.3	3.6	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
3	Services - Other	L116 + L126	502.2	472.7	558.3	513.3	475.8	(37.5)	500.9	492.4	(8.5)	548.0
4	Materials	L117 + L127	48.7	48.8	53.2	46.6	54.2	7.7	46.5	49.3	2.7	49.7
5	Buildings & Equipment	L118 + L128	67.7	67.6	74.0	52.2	63.8	11.6	52.1	52.7	0.6	52.2
6	F17-F19 RRA Compliance Filing Adjustment	L119 + L130	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	F21 Forecast Adjustment	L120	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.6	26.6	0.0
			1,192.4	1,168.6	1,262.3	1,229.2	1,216.9	(12.3)	1,226.9	1,243.9	17.1	1,328.8
Less:												
8	Eligible Capital Overhead	L121 + L132	(67.0)	(69.0)	(69.9)	(71.0)	(72.0)	(1.1)	(71.4)	(73.2)	(1.9)	(75.5)
9	External Recoveries	L122 + L129	(23.9)	(23.1)	(27.3)	(22.1)	(29.6)	(7.5)	(20.1)	(22.3)	(2.2)	(26.6)
10	Total Gross Operating Costs Including Regulatory Account Additions	5.0 L68	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,226.7
11	Total Gross Provision & Other Including Regulatory Account Additions	5.01 L43	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
12	Total Gross Operating Cost and Provision & Other Including Regulatory Account Additions		1,165.1	1,228.7	1,277.0	1,252.5	1,292.0	39.5	1,230.8	1,346.3	115.5	1,328.1
Less Operating Costs Reg. Acct. Additions												
Demand-Side Management												
13	Labour		(20.8)	(20.9)	(21.7)	(23.3)	(22.5)	0.8	(23.2)	(23.9)	(0.7)	(25.3)
14	Services - ABSU		(0.8)	(0.4)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Services - Other		(75.2)	(60.6)	(88.8)	(84.8)	(71.6)	13.1	(74.7)	(65.3)	9.4	(71.6)
16	Materials		(0.3)	(0.2)	(0.1)	(0.3)	(0.2)	0.0	(0.3)	(0.3)	0.0	(0.2)
17	Buildings & Equipment		(0.4)	(0.4)	(0.6)	(0.8)	(1.1)	(0.3)	(0.6)	(0.6)	0.0	(0.7)
18	F17-F19 RRA Compliance Filing Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
First Nations Costs												
19	Labour		(1.0)	(0.9)	(0.9)	(0.9)	(1.0)	(0.1)	(0.8)	(0.9)	(0.1)	(1.2)
20	Services - ABSU		(0.1)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Services - Other		(2.9)	(1.1)	(1.4)	(2.3)	(1.5)	0.8	(1.6)	(1.4)	0.2	(0.9)
22	Materials		(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
23	Buildings & Equipment		(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
Site C Project												
24	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Services - Other		0.0	(0.3)	(0.3)	(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)
27	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storm Restoration												
29	Labour		(4.5)	(4.7)	(4.7)	0.0	0.9	0.9	0.0	0.0	0.0	0.0
30	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Services - Other		(13.6)	(11.1)	(14.1)	0.0	6.6	6.6	0.0	(0.0)	(0.0)	0.0
32	Materials		(0.5)	(0.3)	(0.1)	0.0	0.3	0.3	0.0	0.0	0.0	0.0
33	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Operating Costs and Provisions - Total Company - Supplemental Schedule
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020		F2021			F2022	
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Operating Costs Including Regulatory												
Smart Metering & Infrastructure												
34	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pension Cost												
40	Labour		(10.1)	2.5	(0.7)	0.0	0.9	0.9	0.0	5.8	5.8	0.0
41	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pension Cost - F17-F19 RRA Compliance Filing Adjustment												
45	Labour		0.0	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real Property Sales												
50	Labour		(0.4)	(0.5)	(0.3)	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0
51	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Services - Other		(0.4)	(1.1)	(0.3)	0.0	(0.6)	(0.6)	0.0	0.0	0.0	0.0
53	Materials		(0.0)	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
54	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer Crisis Fund												
55	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	Services - Other		0.0	(0.1)	2.7	0.3	2.7	2.4	0.3	(0.9)	(1.2)	(0.0)
58	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electric Vehicle Costs												
60	Labour		0.0	0.0	0.0	(0.7)	0.0	0.7	(0.7)	(0.7)	0.0	0.0
62	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Services - Other		0.0	0.0	0.0	(1.2)	0.0	1.2	(1.0)	(1.0)	0.0	0.0
64	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mining Customer Payment Plan												
66	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)	(0.6)	0.0
69	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	IFRS Capitalized Overhead	5.0 L60	(112.0)	(89.6)	(67.2)	(44.8)	(44.8)	0.0	(22.4)	(22.4)	0.0	0.0
72	Total Operating Costs Reg. Acct. Additions	5.0 L67	(242.9)	(179.8)	(198.7)	(159.0)	(132.6)	26.4	(125.4)	(112.4)	12.9	(100.2)

Operating Costs and Provisions - Total Company - Supplemental Schedule
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Operating Costs Including Regulatory												
Less Provisions Reg. Acct. Additions												
73	First Nations Provisions	5.01 L35	3.3	(0.9)	(2.4)	0.0	(0.9)	(0.9)	0.0	(1.2)	(1.2)	0.0
74	Environmental Provisions	5.01 L36	28.0	4.0	7.1	0.0	(51.2)	(51.2)	0.0	(96.0)	(96.0)	0.0
75	Arrow Water Provision	5.01 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	Smart Metering & Infrastructure DSMD Write-Off	5.01 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
77	Real Property Sales	5.01 L39	(9.0)	(6.8)	(9.4)	0.0	(4.4)	(4.4)	0.0	0.0	(0.0)	0.0
78	Dismantling Cost	5.01 L40	(2.9)	(31.7)	(11.3)	0.0	8.5	8.5	0.0	(5.1)	(5.1)	0.0
79	Project Write-Off Costs	5.01 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
80	Total Provisions Reg. Acct. Additions	5.01 L42	19.5	(35.4)	(16.0)	0.0	(48.0)	(48.0)	0.0	(102.2)	(102.2)	0.0
81	Total Regulatory Account Additions	L72 + L80 (or 3.0 L22+L28)	(223.4)	(215.3)	(214.8)	(159.0)	(180.6)	(21.6)	(125.4)	(214.7)	(89.3)	(100.2)
Less Operating Costs Def. Acct. Additions												
Transfers to HDA												
82	Labour		0.0	(0.1)	(0.1)	0.0	0.1	0.1	0.0	0.0	0.0	0.0
83	Services - Other		0.1	(0.2)	0.3	0.0	1.3	1.3	0.0	0.7	0.7	0.0
84	Materials		(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
Transfers to NHDA												
85	Labour		(0.1)	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	Services - Other		9.1	36.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Materials		0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Provisions Def. Acct. Additions												
Transfers to NHDA												
88	Provision & Other	5.01 L33		(1.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
89	Total Deferral Account Additions	5.0 L54+5.01 L34 (or 3.0 L21+L27)	9.0	33.7	0.7	0.0	1.4	1.4	0.0	0.7	0.7	0.0
Add Regulatory Account Recoveries												
90	First Nation Costs	5.0 L26	32.4	38.7	39.3	34.7	34.1	(0.6)	33.7	33.6	(0.1)	34.4
91	Storm Restoration	5.0 L27	10.8	10.4	10.0	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)
92	Capital Project Investigation	5.0 L28	4.8	4.8	4.8	5.2	5.2	0.0	5.2	5.2	0.0	0.0
93	Smart Metering & Infrastructure	5.0 L29	32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	26.6
94	Home Purchase Offer Plan	5.0 L30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95	Minimum Reconnection Charge	5.0 L31	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	Non-Current Pension Cost	5.0 L32	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
97	PEB Current Pension Costs	5.0 L33	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
98	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	5.0 L34	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
99	IFRS PP&E	5.0 L35	23.2	26.0	28.2	29.9	29.9	0.0	31.0	31.0	0.0	31.6
100	IFRS Pension	5.0 L36	38.2	38.2	38.2	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2
101	Electric Vehicle Costs	5.0 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
102	Total Regulatory Account Recoveries (Operating Costs)	5.0 L38	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	230.7

Operating Costs and Provisions - Total Company - Supplemental Schedule
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Operating Costs Including Regulatory												
103	Remediation (PCB)	5.01 L17	18.3	18.9	15.3	22.5	22.5	(0.0)	22.7	22.7	0.0	53.1
104	Remediation (Asbestos)	5.01 L18	24.4	16.6	15.3	9.1	9.1	(0.0)	6.4	6.4	0.0	5.0
105	Dismantling Expense	5.01 L19	0.0	0.0	0.0	25.5	25.5	(0.0)	24.6	24.6	0.0	(3.3)
106	Rock Bay Remediation	5.01 L20	(3.8)	(3.2)	0.0	(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)
107	Arrow Water Divestiture Costs	5.01 L21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
108	Arrow Water Provision	5.01 L22	0.3	1.8	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	Rate Smoothing	5.01 L23	(201.2)	(326.2)	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110	Project Write-Off Costs	5.01 L24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3
111	Total Regulatory Account Recoveries (Provisions & Other)	5.01 L25	(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
112	Total Regulatory Account Recoveries	L102 + L111 (or 3.0 L24+L30)	40.3	(74.3)	1,063.9	264.9	269.8	4.9	260.0	259.9	(0.1)	294.7
113	Total Current Operating Costs & Provisions & Other	5.0 L51 + 5.01 L26 (or 3.0 L25+L31)	990.9	972.8	2,126.9	1,358.4	1,382.6	24.2	1,365.4	1,392.2	26.8	1,522.6
SUMMARY OF OPERATING COSTS ABOVE												
Operating Costs Before Deferrals												
114	Labour (excl Non-Current PEB)	5.0 L16	487.8	522.2	544.8	592.2	601.1	8.9	602.5	603.2	0.8	652.5
115	Services - ABSU	5.0 L17	48.1	41.9	3.6	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
116	Services - Other	5.0 L18	419.3	434.2	456.8	425.0	412.4	(12.7)	423.6	423.6	0.0	475.1
117	Materials	5.0 L19	47.9	48.2	52.9	46.3	54.3	8.0	46.3	49.0	2.7	49.5
118	Buildings & Equipment	5.0 L20	67.4	67.2	73.4	51.4	62.7	11.3	51.5	52.1	0.6	51.5
119	F17-F19 RRA Compliance Filing Adjustment	5.0 L23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
120	F21 Forecast Adjustment	5.0 L24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.6	26.6	0.0
Less:												
121	Capital Overhead	5.0 L21	(179.0)	(158.6)	(137.1)	(115.8)	(116.9)	(1.1)	(93.8)	(95.6)	(1.9)	(75.5)
122	External Recoveries	5.0 L22	(23.9)	(23.1)	(27.3)	(22.1)	(29.6)	(7.5)	(20.1)	(22.3)	(2.2)	(26.6)
123	Total Operating Costs Before Deferrals	5.0 L25	867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5

Operating Costs and Provisions - Total Company - Supplemental Schedule
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Operating Costs Including Regulatory Deferred Operating Costs												
124	Labour (excl Non-Current PEB)	-(L13 + L19 + L24 + L29 + L34 + L40 + L45 + L50 + L55 + L61 + L66 + L82 + L85)	37.0	15.0	28.4	24.9	21.9	(2.9)	24.8	19.8	(5.0)	26.5
125	Services - ABSU	-(L14 + L20 + L25 + L30 + L35 + L41 + L46 + L51 + L56 + L62 + L67)	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
126	Services - Other	-(L15 + L21 + L26 + L31 + L36 + L42 + L47 + L52 + L57 + L63 + L68 + L83 + L86)	82.9	38.4	101.5	88.3	63.5	(24.8)	77.4	68.8	(8.6)	72.8
127	Materials	-(L16 + L22 + L27 + L32 + L37 + L43 + L48 + L53 + L58 + L64 + L69 + L84 + L87)	0.8	0.6	0.2	0.3	(0.1)	(0.3)	0.3	0.2	(0.0)	0.2
128	Buildings & Equipment	-(L17 + L23 + L28 + L33 + L38 + L44 + L49 + L54 + L59 + L65 + L70)	0.4	0.4	0.6	0.8	1.1	0.3	0.6	0.6	0.0	0.7
129	External Recoveries	- L39	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
130	F17-F19 RRA Compliance Filing Adjustment	-L18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
131	Total Deferred Operating Costs		121.9	54.9	130.8	114.2	86.4	(27.8)	103.0	89.4	(13.6)	100.2
132	IFRS Capitalized Overhead	5.0 L60	112.0	89.6	67.2	44.8	44.8	0.0	22.4	22.4	0.0	0.0
133	Total Operating Costs Including Deferrals	Line 10	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,226.7
134	Provisions & Other	Line 11	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
135	Total Gross Operating Cost and Provision & Other Including Deferrals	Line 12	1,165.1	1,228.7	1,277.0	1,252.5	1,292.0	39.5	1,230.8	1,346.3	115.5	1,328.1
Less												
136	Deferral Account Additions	L72 + L89	(233.9)	(146.1)	(198.0)	(159.0)	(131.2)	27.8	(125.4)	(111.8)	13.6	(100.2)
137	Deferred Provisions & Other	Line 80	19.5	(35.4)	(16.0)	0.0	(48.0)	(48.0)	0.0	(102.2)	(102.2)	0.0
Add												
138	Regulatory Account Recoveries Bf Provisions & Other	Line 102	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	230.7
139	Provisions & Other Regulatory Account Recoveries	Line 111	(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
140	Total Current Operating Costs & Provisions & Other	Line 113	990.9	972.8	2,126.9	1,358.4	1,382.6	24.2	1,365.4	1,392.2	26.8	1,522.6
141	Current Operating Costs	L123 + L138	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,357.2

BC Hydro

F22 RRA

Operating Costs - Integrated Planning
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by KBU												
1			5.7	5.9	6.7	7.9	8.2	0.2	8.4	10.2	1.9	9.0
2			8.4	8.6	9.7	10.2	9.8	(0.4)	10.3	10.9	0.5	11.4
3			102.8	108.0	98.5	97.0	95.6	(1.4)	98.1	91.7	(6.4)	103.2
4			107.4	114.7	128.4	126.6	130.7	4.1	127.7	133.1	5.4	168.2
5			10.3	8.8	10.7	10.5	13.1	2.6	10.6	13.2	2.5	11.3
6			16.2	17.0	18.0	19.1	18.7	(0.4)	19.4	18.5	(0.9)	18.2
7			3.0	3.5	4.4	5.5	5.3	(0.2)	5.6	6.8	1.1	9.0
8			34.0	20.1	12.4	15.9	11.1	(4.8)	15.1	16.6	1.5	15.9
9			287.9	286.6	288.8	292.7	292.5	(0.3)	295.2	300.8	5.6	346.2
Base Operating Costs												
10			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12			0.0	0.0	3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
13		15.0 L21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14			0.0	0.0	3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
Total Base Operating Costs												
15			287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	352.2
Adjustment												
Net Operating Costs												
Operating Costs by Resource												
16			140.6	143.7	147.7	147.6	154.2	6.7	149.7	153.3	3.6	165.8
17			1.5	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18			129.3	125.1	130.0	149.1	132.4	(16.7)	149.6	148.4	(1.2)	182.2
19			13.4	13.6	14.5	11.2	13.3	2.1	11.2	14.7	3.5	15.1
20			14.5	13.9	16.2	2.5	12.4	9.9	2.5	2.0	(0.5)	1.9
21			0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
22			(11.4)	(11.1)	(16.0)	(11.9)	(14.6)	(2.7)	(11.9)	(11.9)	0.0	(12.7)
23			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0
24			287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	352.2

BC Hydro

F22 RRA

Operating Costs - Capital Infrastructure Project Delivery
(\$ million)

			F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
Line	Column	Reference	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by KBU												
1	Project Delivery		12.7	13.5	13.4	14.0	13.9	(0.1)	14.5	13.9	(0.6)	15.4
2	Indigenous Relations		7.3	6.1	6.7	6.1	6.1	(0.1)	6.3	6.2	(0.1)	6.7
3	Environment		26.2	27.0	29.0	29.8	29.4	(0.4)	30.0	30.1	0.2	31.0
4	Properties		32.2	32.7	36.1	29.3	30.0	0.7	29.5	29.8	0.3	30.3
5	Business Unit Support		0.7	0.7	0.8	0.8	0.8	(0.0)	0.9	0.8	(0.0)	0.9
6	Base Operating Costs		79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3
7	IFRS Ineligible Capitalized Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Independent Power Producer Capital Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Total Base Operating Costs Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Net Operating Costs		79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3
Operating Costs by Resource												
13	Labour		28.7	30.2	31.4	34.1	33.8	(0.3)	35.1	35.8	0.6	38.1
14	Services - ABSU		2.8	2.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Services - Other		51.7	49.3	57.2	51.5	52.6	1.1	49.4	52.4	3.0	56.0
16	Materials		1.2	1.2	1.4	1.1	0.4	(0.6)	1.1	0.4	(0.7)	0.4
17	Buildings & Equipment		7.0	7.9	6.6	3.6	3.7	0.1	3.7	3.9	0.2	3.6
18	Capitalized Overhead		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
19	External Recoveries		(12.1)	(11.2)	(10.8)	(10.2)	(10.3)	(0.1)	(8.2)	(10.4)	(2.2)	(13.9)
20	F21 Forecast Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.1)	(1.1)	0.0
21	Total		79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3

BC Hydro

F22 RRA

Operating Costs - Operations
(\$ million)

		Reference	F2017	F2018	F2019	F2020	F2021	F2022				
Line	Column		Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by KBU												
1		Program and Contract Management	11.6	11.9	12.3	14.0	16.2	2.2	14.2	16.2	2.0	17.3
2		Line Field Operations	69.4	71.2	70.9	85.9	87.0	1.1	86.7	92.9	6.2	92.3
3		Stations Field Operations	41.5	39.4	43.6	52.9	51.3	(1.6)	53.5	60.1	6.7	55.8
4		Distribution Design and Customer Connect	10.2	10.6	14.9	14.8	15.9	1.1	15.1	16.9	1.8	16.4
5		Construction Services	11.4	12.4	12.4	13.2	13.2	0.0	13.3	16.7	3.4	14.9
6		Generation System Operations	20.5	19.1	18.8	19.7	19.2	(0.5)	20.0	18.8	(1.2)	19.8
7		Transmission and Distribution System Operations	38.2	40.4	38.7	39.8	40.4	0.6	40.3	40.2	(0.1)	41.6
8		Business Unit Support	2.7	3.8	5.3	2.8	3.7	1.0	2.8	2.1	(0.7)	3.3
9		Base Operating Costs	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4
10		IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11		Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12		Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13		Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14		Total Base Operating Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15		Adjustment										
15		Net Operating Costs	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4
Operating Costs by Resource												
16		Labour	144.2	147.1	148.2	163.6	167.4	3.8	166.4	168.0	1.6	182.3
17		Services - ABSU	1.8	1.3	0.1	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
18		Services - Other	43.8	43.2	50.5	62.3	62.4	0.0	62.4	62.8	0.4	62.2
19		Materials	8.9	9.5	10.1	10.2	10.5	0.3	10.2	9.3	(0.9)	9.4
20		Buildings & Equipment	7.0	7.5	7.9	6.8	6.5	(0.3)	6.8	7.7	0.9	7.5
21		Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22		External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23		F21 Forecast Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	16.1	0.0
24		Total	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4

BC Hydro

F22 RRA

Operating Costs - Safety
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by KBU												
1			14.5	14.7	12.1	13.1	12.4	(0.7)	13.3	13.3	0.0	13.3
2			25.7	23.2	23.8	25.8	23.2	(2.6)	26.2	25.8	(0.4)	26.3
3			5.7	5.7	6.6	6.6	6.4	(0.1)	6.7	6.9	0.3	7.4
4			9.4	9.2	10.5	10.7	12.3	1.6	10.8	19.4	8.6	12.5
5			0.7	0.9	0.8	1.0	1.4	0.4	1.0	3.7	2.7	8.1
6			0.6	0.6	0.6	0.6	0.6	(0.0)	0.6	0.6	(0.0)	0.8
7			56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
Base Operating Costs												
8			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Base Operating Costs												
Adjustment												
13			56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
Net Operating Costs												
Operating Costs by Resource												
14			35.9	35.6	35.9	38.7	37.1	(1.6)	39.4	39.9	0.5	45.7
15			0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16			17.8	16.2	16.8	18.0	17.7	(0.3)	18.0	18.9	0.9	21.4
17			1.8	1.2	1.0	0.8	1.1	0.2	0.8	0.7	(0.1)	0.7
18			0.7	0.7	0.7	0.3	0.6	0.3	0.3	0.5	0.2	0.5
19			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21			0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.7	9.7	0.0
22			56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3

BC Hydro

F22 RRA

Operating Costs - Finance, Technology, Supply Chain
(\$ million)

Line	Reference	Column	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by KBU												
1		Finance	28.7	28.7	29.4	31.6	31.6	0.0	32.1	45.8	13.7	51.0
2		Technology	134.5	128.3	137.1	135.8	138.4	2.6	136.4	138.9	2.5	146.3
3		Supply Chain	89.9	89.0	94.0	94.5	94.3	(0.2)	95.5	95.9	0.4	101.0
4		Business Unit Support	0.7	0.7	0.8	0.8	0.8	(0.0)	0.8	0.8	0.0	0.9
5		Base Operating Costs	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
6		IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7		Independent Power Producer Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8		Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9		Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10		Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Total Base Operating Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Adjustment										
11		Net Operating Costs	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
Operating Costs by Resource												
12		Labour	93.8	101.7	107.0	115.6	115.2	(0.5)	117.8	123.8	6.0	132.5
13		Services - ABSU	4.8	3.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14		Services - Other	96.2	85.0	90.7	88.5	89.0	0.5	88.5	96.2	7.7	107.4
15		Materials	22.1	21.3	24.3	21.9	27.2	5.4	21.9	22.2	0.3	22.2
16		Buildings & Equipment	37.3	36.0	39.3	36.6	38.3	1.7	36.6	37.0	0.4	37.0
17		Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18		External Recoveries	(0.4)	(0.9)	(0.4)	0.0	(4.7)	(4.7)	0.0	0.0	0.0	0.0
19		F21 Forecast Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	0.0
20		Total	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1

BC Hydro

F22 RRA

Operating Costs - People, Customer, Corporate Affairs
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by KBU												
1			21.6	22.1	20.1	21.1	21.0	(0.1)	21.4	21.5	0.1	23.2
2			68.9	68.7	59.0	62.4	60.5	(1.9)	63.0	61.8	(1.2)	68.6
3			0.6	0.5	0.5	0.6	0.6	(0.0)	0.6	0.4	(0.2)	0.7
4			12.4	13.7	13.7	12.9	12.7	(0.2)	13.0	13.6	0.6	14.2
5			5.1	4.5	5.5	5.4	8.1	2.8	5.4	12.8	7.4	13.1
6			0.5	0.6	0.8	1.0	1.0	(0.0)	1.0	1.1	0.1	1.1
7			0.8	0.7	0.7	0.8	0.7	(0.1)	0.8	0.8	0.0	0.9
8			Base Operating Costs									
			110.0	111.0	100.4	104.2	104.7	0.4	105.4	112.1	6.8	121.8
9			IFRS Ineligible Capitalized Costs			0.0	0.0	0.0	0.0	0.0	0.0	0.0
10			Independent Power Producer Capital Leases			0.0	0.0	0.0	0.0	0.0	0.0	0.0
11			Waneta 2/3			0.0	0.0	0.0	0.0	0.0	0.0	0.0
12			Customer Crisis Fund			0.0	0.0	4.1	5.3	5.3	(0.0)	0.5
13			Total Base Operating Costs Adjustment									
			0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	(0.0)	0.5
14			Net Operating Costs									
			110.0	111.0	104.5	109.5	109.1	(0.5)	110.7	117.4	6.8	122.3
Operating Costs by Resource												
15			Labour			40.5	44.0	64.6	70.6	70.1	(0.4)	81.2
16			Services - ABSU			37.1	33.1	3.0	0.0	0.0	0.0	0.0
17			Services - Other			31.3	31.9	34.3	36.5	36.2	(0.3)	38.7
18			Materials			0.5	1.2	1.4	1.1	1.7	0.6	1.6
19			Buildings & Equipment			0.7	0.9	1.2	1.4	1.0	(0.4)	0.8
20			Capitalized Overhead			0.0	0.0	0.0	0.0	0.0	0.0	0.0
21			External Recoveries			0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
22			F21 Forecast Adjustment			0.0	0.0	0.0	0.0	0.0	0.0	0.0
23			Total			110.0	111.0	104.5	109.5	109.1	(0.5)	122.3

BC Hydro

F22 RRA

Operating Costs - Other
(\$ million)

Line	Reference Column	F2017	F2018	F2019	F2020			F2021			F2022
		Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Operating Costs by KBU											
1	Office of the General Counsel	11.1	10.6	11.1	11.7	12.0	0.3	11.8	13.4	1.6	13.0
2	Office of the President and Chief Executive Officer	1.0	0.8	0.9	0.9	0.8	(0.0)	0.9	0.8	(0.0)	0.9
3	Site C Project	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Corporate Costs	13.1	28.4	22.3	28.9	32.7	3.8	29.1	(4.3)	(33.5)	0.5
5	Capitalized Costs	(281.8)	(283.9)	(284.8)	(285.8)	(287.0)	(1.2)	(286.2)	(285.9)	0.3	(290.4)
6	Base Operating Costs	(256.6)	(244.0)	(250.5)	(244.3)	(241.4)	2.9	(244.4)	(275.9)	(31.5)	(276.0)
7	IFRS Ineligible Capitalized Costs	102.9	125.3	147.7	170.1	170.1	0.0	192.5	192.5	0.0	214.9
8	Independent Power Producer Capital Leases	28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Total Base Operating Costs Adjustment	131.0	188.8	202.0	170.1	170.1	0.0	192.5	192.5	0.0	214.9
12	Net Operating Costs	(125.6)	(55.2)	(48.5)	(74.3)	(71.4)	2.9	(52.0)	(83.5)	(31.5)	(61.1)
Operating Costs by Resource											
13	Labour	4.1	19.9	9.9	22.1	23.3	1.2	22.4	5.5	(16.8)	6.9
14	Services - ABSU	(0.3)	(0.4)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Services - Other	49.2	83.6	77.3	19.1	22.1	3.0	19.1	6.5	(12.6)	7.2
16	Materials	0.1	0.1	0.2	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1
17	Buildings & Equipment	0.2	0.2	1.3	0.2	0.2	(0.0)	0.2	0.2	(0.0)	0.2
18	Capitalized Overhead	(179.0)	(158.6)	(137.1)	(115.8)	(117.0)	(1.2)	(93.8)	(95.6)	(1.9)	(75.5)
19	External Recoveries	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	F21 Forecast Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	(0.2)	0.0
21	Total	(125.6)	(55.2)	(48.5)	(74.3)	(71.4)	2.9	(52.0)	(83.5)	(31.5)	(61.1)

BC Hydro
F22 RRATaxes
(\$ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Generation												
1	Grants in Lieu		24.0	24.4	25.6	26.9	26.6	(0.3)	27.9	27.5	(0.5)	28.2
2	School Taxes		16.5	16.5	16.9	17.4	17.7	0.3	18.3	17.7	(0.6)	17.9
3	Total		40.5	40.9	42.5	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1
Transmission												
4	Grants in Lieu		52.1	55.0	60.5	63.6	64.9	1.3	65.7	67.8	2.0	68.6
5	School Taxes		85.8	88.8	91.8	94.0	93.5	(0.5)	98.0	95.4	(2.6)	98.4
6	Total		137.9	143.8	152.3	157.6	158.4	0.8	163.7	163.1	(0.6)	167.0
Distribution												
7	Grants in Lieu		7.5	7.8	8.2	8.5	8.6	0.0	8.9	8.9	0.1	9.2
8	School Taxes		19.3	19.7	20.0	20.6	20.0	(0.6)	24.0	20.6	(3.4)	22.5
9	Total		26.8	27.5	28.3	29.1	28.6	(0.6)	32.9	29.5	(3.3)	31.7
Customer Care												
10	IPP Capital Leases Waneta 2/3		2.6	4.2	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Teck portion of property taxes	15.0 L23	0.0	0.0	0.1	0.6	0.9	0.3	0.6	0.8	0.2	0.8
12	Total		2.6	4.2	2.6	0.6	0.9	0.3	0.6	0.8	0.2	0.8
Business Support												
13	Grants in Lieu		10.0	10.5	10.9	11.8	11.3	(0.6)	12.2	11.5	(0.7)	12.0
14	School Taxes		5.7	6.1	6.1	6.3	6.4	0.1	6.5	4.6	(1.8)	6.2
15	Total		15.7	16.5	17.0	18.2	17.7	(0.5)	18.7	16.1	(2.6)	18.2
Total Before Regulatory Accounts												
15	Grants in Lieu	L1+L4+L7+L13	93.6	97.7	105.2	110.8	111.3	0.5	114.8	115.7	0.9	118.0
16	School Taxes	L2+L5+L8+L14	127.3	131.1	134.9	138.3	137.5	(0.8)	146.8	138.3	(8.4)	145.0
17	IPP Capital Leases	L10	2.6	4.2	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Waneta 2/3 Property Taxes	L11	0.0	0.0	0.1	0.6	0.9	0.3	0.6	0.8	0.2	0.8
19	Total		223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
Deferral Account Additions												
20	Transfers to NHDA		(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Total Gross Taxes	L19 + L20	223.1	231.1	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
Deferral Account Additions												
22	Transfers to NHDA		0.4	1.9	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total Current Taxes	L21 + L22	223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
Allocation of Current Taxes												
24	Generation	Line 3	40.5	40.9	42.5	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1
25	Transmission	Line 6	137.9	143.8	152.3	157.6	158.4	0.8	163.7	163.1	(0.6)	167.0
26	Distribution	Line 9	26.8	27.5	28.3	29.1	28.6	(0.6)	32.9	29.5	(3.3)	31.7
27	Customer Care	Line 12	2.6	4.2	2.6	0.6	0.9	0.3	0.6	0.8	0.2	0.8
28	Business Support	Line 15	15.7	16.5	17.0	18.2	17.7	(0.5)	18.7	16.1	(2.6)	18.2
29	Total		223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8

BC Hydro
F22 RRADepreciation and Amortization
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Amortization of Capital Assets												
1	Generation	12.2 L8:L9	195.9	198.8	234.5	260.9	262.7	1.8	266.8	272.2	5.4	278.5
2	Transmission	12.3 L8:L9	206.8	216.3	224.0	228.4	229.2	0.8	230.8	228.6	(2.2)	233.8
3	Distribution	12.4 L8:L9	184.3	191.4	200.2	206.3	207.3	1.1	216.5	215.3	(1.2)	225.4
4	Business Support	12.1 L8:L9	168.6	185.8	189.8	189.9	186.6	(3.3)	190.4	187.0	(3.4)	191.7
5	Total		755.5	792.2	848.5	885.4	885.8	0.4	904.5	903.1	(1.4)	929.4
Dismantling Costs												
6	Generation		0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Transmission		2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Distribution		5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Business Support		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Total		8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPP Capital Leases												
11	IPP Capital Leases		17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
12	Total		17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
Other Leases												
13	Amortization		0.0	0.0	0.0	3.4	2.6	(0.8)	3.4	3.7	0.2	3.7
Deferral Account Additions												
14	Transfers to NHDA		(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
15	Total		(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
16	Less: Electric Vehicle Costs - Ineligible stations					(0.0)		0.0	(0.0)		0.0	
17	Total Gross Amortization		777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
Deferral Account Additions												
18	Transfers to NHDA		3.3	14.0	0.0	0.0	(0.4)	(0.4)	0.0	0.2	0.2	0.0
Transfer to Regulatory Account												
19	Amortization on Additions Variance	13.0 L35 - Line20	2.0	(0.7)	(20.4)	0.0	0.4	0.4	0.0	1.6	1.6	0.0
20	Electric Vehicle Costs Additions - New Assets					0.0	0.0	0.0	(0.3)	(0.3)	0.0	0.0
21	Electric Vehicle Costs Additions - Existing Assets					(0.2)	0.0	0.2	(0.2)	(0.2)	0.0	0.0
22	Transfer to Regulatory Account		2.0	(0.7)	(20.4)	(0.2)	0.4	0.7	(0.5)	1.1	1.6	0.0

BC Hydro
F22 RRADepreciation and Amortization
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Regulatory Account Recoveries												
DSM Amortization												
23		(2.2 L5:L6) * 90%	80.2	86.0	89.3	93.0	93.0	(0.0)	96.7	95.8	(0.8)	97.2
24		(2.2 L5:L6) * 5%	8.9	9.6	5.0	5.2	5.2	(0.0)	5.4	5.3	(0.0)	5.4
25		(2.2 L5:L6) * 5%	0.0	0.0	5.0	5.2	5.2	(0.0)	5.4	5.3	(0.0)	5.4
26		Total	89.1	95.6	99.3	103.3	103.3	(0.0)	107.4	106.5	(0.9)	108.0
FRSR Amortization												
27		Line 6	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28		Line 7	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29		Line 8	(5.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30		Line 9	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31		Total	(8.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32		Pre-1996 CIAC Amortization	0.7	3.2	4.9	5.1	5.1	0.0	5.1	5.1	0.0	5.1
Capital Additions Regulatory Account												
33		2.2 L56	(3.6)	(3.4)	(3.3)	9.7	9.7	(0.0)	9.4	9.4	0.0	(2.1)
34		Total	(3.6)	(3.4)	(3.3)	9.7	9.7	(0.0)	9.4	9.4	0.0	(2.1)
35		Total Recoveries	77.5	95.4	100.9	118.1	118.1	(0.0)	121.9	121.0	(0.9)	111.1
36		Total Current Amortization	860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.7
Allocation of Current Amortization												
37		L1+L23	276.0	284.8	323.8	353.9	355.6	1.8	363.5	368.1	4.6	375.7
38		L2+L24	215.7	225.8	229.0	233.5	234.4	0.8	236.1	233.9	(2.2)	239.2
39		L3+L25+L32	184.9	194.7	210.1	216.5	217.6	1.1	227.0	225.8	(1.2)	235.9
40		L12	17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
41		L4+L13+L16+L19:L21+L33	167.0	181.7	166.1	202.8	199.4	(3.4)	202.7	201.2	(1.5)	193.3
42		Total	860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.7

BC Hydro
F22 RRAFinance Charges
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1		L8 + L20	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
Regulatory Account Additions												
2			3.4	(4.2)	4.0	(2.3)	5.3	7.5	(1.5)	(3.0)	(1.4)	(2.6)
3			(5.6)	(26.5)	(0.1)	0.0	0.3	0.3	0.0	0.2	0.2	0.0
4			17.2	17.2	17.5	17.6	17.6	0.0	18.0	18.0	0.0	18.3
5			3.9	4.4	5.9	5.5	4.8	(0.7)	4.8	3.8	(1.0)	3.4
6			0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7			(187.1)	29.3	321.0	100.9	777.3	676.4	0.0	185.0	185.0	0.0
8			(168.0)	20.4	348.4	121.8	805.3	683.5	21.3	204.1	182.8	19.2
9			747.2	785.5	843.8	753.1	851.5	98.3	722.0	747.4	25.4	536.4
Total Before Regulatory Accounts												
10		Line 70	(8.2)	(8.3)	(8.7)	(7.8)	(9.1)	(1.2)	(7.7)	(5.2)	2.5	(3.2)
11		Line 86	741.3	774.5	814.9	825.3	824.9	(0.4)	851.5	820.9	(30.6)	772.5
12		Line 95	15.8	20.9	39.5	63.8	47.5	(16.2)	69.6	13.8	(55.8)	13.5
13		Line 105	(81.2)	(108.9)	(130.0)	(181.5)	(175.5)	6.0	(242.6)	(237.7)	4.9	(287.4)
14			(12.7)	1.5	28.5	39.2	50.5	11.3	45.1	43.1	(2.0)	47.0
15			25.1	44.7	42.4	48.4	48.4	0.0	46.1	46.1	0.0	43.5
16			1.2	1.1	1.2	1.3	1.3	(0.0)	1.3	1.0	(0.4)	1.0
17			66.0	62.0	55.9	(36.5)	62.1	98.6	(42.2)	64.0	106.2	(52.0)
18			0.0	(2.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19			0.0	0.0	0.0	1.0	1.3	0.2	1.0	1.4	0.4	1.5
20			747.2	785.5	843.8	753.1	851.5	98.3	722.0	747.4	25.4	536.4
21		L16-L3-L20-L22-L25-L26-L27	12.6	25.1	(52.8)	0.0	(0.9)	(0.9)	0.0	76.6	76.6	0.0
22			0.0	0.0	0.0	2.0	1.9	(0.1)	2.7	2.1	(0.6)	7.3
Interest on Regulatory Accounts												
23		2.1 L41	(41.1)	(26.5)	8.2	15.4	15.9	0.5	4.0	4.8	0.8	0.7
24		2.2 L226	(34.2)	(35.2)	(35.7)	(33.1)	(32.6)	0.5	(30.0)	(27.2)	2.8	(25.0)
25			(75.3)	(61.6)	(27.5)	(17.7)	(16.7)	1.0	(26.0)	(22.3)	3.7	(24.3)
Regulatory Account Recoveries												
26			0.4	(38.3)	(39.2)	0.5	0.5	0.0	(0.5)	0.1	0.6	(0.1)
27			(72.6)	(70.0)	(66.8)	0.0	(98.6)	(98.6)	0.0	(106.2)	(106.2)	0.0
28			(101.8)	(101.8)	(101.8)	10.1	10.1	0.0	10.1	10.1	0.0	(74.1)
29			0.0	0.0	0.0	(12.4)	(12.4)	0.0	(12.4)	(12.4)	0.0	9.1
30			(0.8)	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31			(174.9)	(209.4)	(207.9)	(1.7)	(100.3)	(98.6)	(2.8)	(108.3)	(105.6)	(65.2)
32		L3+L20+L21+L22+L25+L31	504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.2

BC Hydro
F22 RRAFinance Charges
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Portion of Rate Base												
33		10.0 L28	41.6%	41.3%	43.9%	46.0%	46.2%	0.2%	45.9%	46.2%	0.3%	45.7%
34		10.0 L29	35.5%	35.6%	34.3%	33.2%	33.0%	-0.1%	32.7%	32.6%	(0.1%)	32.7%
35		10.0 L30	23.0%	23.1%	21.8%	20.8%	20.8%	-0.1%	21.4%	21.2%	(0.2%)	21.6%
36			100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%	-	100.0%
Allocation of Current Finance Charges												
37			209.5	212.0	243.8	338.4	339.9	1.5	319.6	321.4	1.9	207.8
38			178.7	182.5	190.5	243.9	243.0	(0.9)	227.6	226.8	(0.8)	148.3
39			115.7	118.7	121.3	153.4	152.8	(0.6)	148.8	147.4	(1.4)	98.1
40			504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.2
Net Debt												
41		Line 71	(179.4)	(181.8)	(197.3)	(201.2)	(217.3)	(16.1)	(205.9)	(216.4)	(10.5)	(213.8)
42			(48.9)	(41.9)	(83.9)	(10.0)	(115.3)	(105.3)	(10.0)	(10.0)	0.0	(10.0)
43		Line 81	17,185.3	18,311.1	19,437.1	20,777.8	20,942.6	164.8	21,956.8	22,307.7	350.9	23,080.9
44		Line 90	2,838.5	2,053.0	2,944.7	2,950.3	2,743.5	(206.8)	3,139.9	2,914.9	(225.0)	3,233.5
45			19,795.5	20,140.4	22,100.6	23,516.9	23,353.4	(163.4)	24,880.8	24,996.2	115.4	26,090.6
46			180.1	178.8	231.6	180.2	291.1	110.9	188.0	197.3	9.4	197.4
47			19,975.6	20,319.2	22,332.2	23,697.0	23,644.5	(52.5)	25,068.8	25,193.6	124.8	26,288.0
48			19,068.2	20,147.4	21,325.7	23,014.6	22,988.3	(26.3)	24,382.9	24,419.0	36.1	25,740.8
Weighted Average Cost of Debt (WACD) Rate												
49		Line 1	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
50			177.6	(8.5)	(341.8)	1.8	(796.1)	(797.9)	165.4	(129.7)	(295.1)	239.5
51			756.8	797.5	850.4	876.7	860.6	(16.1)	908.7	821.8	(86.9)	795.1
52			3.97%	3.96%	3.99%	3.81%	3.74%	(0.07%)	3.73%	3.37%	(0.36%)	3.09%
Increase in Cash												
53		9.0 L33	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
54		9.0 L4	(584.6)	0.0	(159.0)	(59.0)	(59.0)	0.0	0.0	0.0	0.0	0.0
55		7.0 L17	777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
56		2.1 L40	63.3	203.7	586.0	3.1	52.2	49.1	3.5	(30.8)	(34.3)	15.5
57		2.1 L42	223.7	233.2	240.6	(403.9)	(403.9)	0.1	(226.9)	(238.3)	(11.5)	0.0
58		2.2 L225	(46.8)	(237.7)	(636.4)	(267.7)	(984.2)	(716.5)	(133.1)	(382.7)	(249.6)	(112.1)
59		2.2 L227	(57.0)	(188.4)	956.9	386.7	287.7	(99.1)	384.6	272.6	(112.0)	340.6
60		2.2 L17	(3.3)	0.9	2.4	0.0	0.9	0.9	0.0	1.2	1.2	0.0
61		2.2 L87	(28.0)	(4.0)	(7.1)	0.0	51.2	51.2	0.0	96.0	96.0	0.0
62		13.0 L12	(2,435.5)	(2,464.9)	(3,816.7)	(2,988.3)	(3,071.4)	(83.1)	(3,104.2)	(3,086.0)	18.2	(2,959.0)
63		11.0 L36	138.4	156.2	185.0	157.8	178.8	21.0	148.5	159.7	11.2	214.2
64		Line 69	(4.6)	5.9	(6.8)	3.9	(11.0)	(14.9)	3.1	6.1	3.1	5.7
65			(538.2)	463.1	194.3	131.4	971.9	840.5	(153.9)	(21.5)	132.4	(332.4)
66			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67			(1,811.2)	(340.3)	(2,017.7)	(1,346.3)	(1,304.2)	42.1	(1,368.6)	(1,536.6)	(168.0)	(1,091.8)

BC Hydro
F22 RRAFinance Charges
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Sinking Funds												
68			166.6	179.4	181.8	197.3	197.3	0.0	201.2	217.3	16.1	216.4
69			4.6	(5.9)	6.8	(3.9)	11.0	14.9	(3.1)	(6.1)	(3.1)	(5.7)
70			8.2	8.3	8.7	7.8	9.1	1.2	7.7	5.2	(2.5)	3.2
71			179.4	181.8	197.3	201.2	217.3	16.1	205.9	216.4	10.5	213.8
72			173.0	180.6	189.5	199.2	207.3	8.1	203.5	216.8	13.3	215.1
Long-Term Debt												
73			15,836.6	17,185.3	18,311.1	19,437.1	19,437.1	0.0	20,777.8	20,942.6	164.8	22,307.7
74			0.0	(40.0)	(1,286.7)	(175.0)	(175.0)	0.0	(1,099.8)	(1,099.8)	(0.0)	(526.3)
75			1,350.0	1,200.0	2,450.0	0.0	1,500.0	1,500.0	0.0	2,200.0	2,200.0	0.0
76			0.0	0.0	0.0	1,500.0	0.0	(1,500.0)	2,300.0	0.0	(2,300.0)	1,350.0
77			19.1	19.7	1.9	(18.4)	78.8	97.2	(16.2)	(21.0)	(4.8)	(29.1)
78			(1.5)	(1.7)	(1.8)	0.0	(2.0)	(2.0)	0.0	0.0	0.0	0.0
79			(9.7)	(44.0)	(31.8)	40.5	108.1	67.6	0.0	302.2	302.2	0.0
80			(9.2)	(8.2)	(5.6)	(6.4)	(4.4)	2.0	(5.0)	(16.2)	(11.2)	(21.3)
81			17,185.3	18,311.1	19,437.1	20,777.8	20,942.6	164.8	21,956.8	22,307.7	350.9	23,080.9
82			16,511.0	17,748.2	18,874.1	20,107.4	20,189.8	82.4	21,367.3	21,625.1	257.9	22,694.3
83						3.46%			3.76%	1.52%		1.91%
84			741.3	774.5	814.9	799.4	824.9	25.6	756.3	820.9	64.6	759.6
85			0.0	0.0	0.0	25.9	0.0	(25.9)	95.2	0.0	(95.2)	12.9
86			741.3	774.5	814.9	825.3	824.9	(0.4)	851.5	820.9	(30.6)	772.5
Short-Term Debt												
87			2,376.0	2,838.5	2,053.0	2,944.7	2,944.7	0.0	2,950.3	2,743.5	(206.8)	2,914.9
88		Line 67	1,811.2	340.3	2,017.7	1,346.3	1,304.2	(42.1)	1,368.6	1,536.6	168.0	1,091.8
89		L73 - L81	(1,348.7)	(1,125.8)	(1,126.0)	(1,340.7)	(1,505.5)	(164.8)	(1,179.0)	(1,365.2)	(186.2)	(773.2)
90			2,838.5	2,053.0	2,944.7	2,950.3	2,743.5	(206.8)	3,139.9	2,914.9	(225.0)	3,233.5
91			2,607.3	2,445.8	2,498.8	2,947.5	2,844.1	(103.4)	3,045.1	2,829.2	(215.9)	3,074.2
92						2.35%			2.69%	0.32%		0.39%
93			15.8	20.9	39.5	69.3	47.5	(21.8)	81.9	13.8	(68.1)	12.0
94			0.0	0.0	0.0	(5.6)	0.0	5.6	(12.3)	0.0	12.3	1.5
95			15.8	20.9	39.5	63.8	47.5	(16.2)	69.6	13.8	(55.8)	13.5
Interest During Construction (IDC) Rate												
96		Line 51	756.8	797.5	850.4	876.7	860.6	(16.1)	908.7	821.8	(86.9)	795.1
97		Line 29	0.0	0.0	0.0	12.4	12.4	0.0	12.4	12.4	0.0	(9.1)
98			756.8	797.5	850.4	889.1	873.0	(16.1)	921.1	834.2	(86.9)	786.1
99		Line 48	19,068.2	20,147.4	21,325.7	23,014.6	22,988.3	(26.3)	24,382.9	24,419.0	36.1	25,740.8
100			3.97%	3.96%	3.99%	3.86%	3.80%	(0.07%)	3.78%	3.42%	(0.36%)	3.05%
Interest Capitalized												
101		13.0 L26	2,936.9	3,859.9	4,430.1	5,347.0	5,463.4	116.3	6,958.5	7,152.3	193.8	8,688.0
102			(891.0)	(1,108.8)	(1,170.1)	(647.5)	(841.9)	(194.5)	(535.5)	(193.6)	342.0	721.7
103			2,045.9	2,751.1	3,260.0	4,699.6	4,621.4	(78.1)	6,423.0	6,958.7	535.7	9,409.6
104		Line 100	3.97%	3.96%	3.99%	3.86%	3.80%	(0.07%)	3.78%	3.42%	(0.36%)	3.05%
105			81.2	108.9	130.0	181.5	175.5	(6.0)	242.6	237.7	(4.9)	287.4

BC Hydro

F22 RRA

Return on Equity
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Shareholder's Equity												
1			4,458.0	4,882.5	5,407.5	4,995.0	4,995.0	0.0	5,706.2	5,698.6	(7.6)	6,389.3
2					74.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3		Line 33	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
4		Line 15	(259.0)	(159.0)	(59.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5			0.0	0.0	0.0	(0.8)	(1.3)	(0.5)	0.0	0.0	0.0	0.0
6			4,882.5	5,407.5	4,995.0	5,706.2	5,698.6	(7.6)	6,418.2	6,389.3	(28.9)	7,101.3
7			230.0	242.7	(220.7)	23.2	273.5	250.3	(46.8)	(909.1)	(862.3)	(43.7)
8			(203.2)	(193.6)	173.1	(70.0)	(317.2)	(247.2)	0.0	865.4	865.4	0.0
9			4,909.3	5,456.6	4,947.4	5,659.3	5,654.8	(4.5)	6,371.3	6,345.6	(25.8)	7,057.6
Dividend to Province												
10		Line 3				712.0			712.0	690.7		712.0
11						712.0			712.0	690.7		712.0
12												
13												
14												
15						0.0						
Capitalization												
16		8.0 L45	19,795.5	20,140.4	22,100.6	23,516.9	23,353.4	(163.4)	24,880.8	24,996.2	115.4	26,090.6
17		Line 9	4,909.3	5,456.6	4,947.4	5,659.3	5,654.8	(4.5)	6,371.3	6,345.6	(25.8)	7,057.6
18			24,704.8	25,597.0	27,048.0	29,176.2	29,008.3	(167.9)	31,252.1	31,341.8	89.6	33,148.1
Capital Structure												
19			80.1%	78.7%	81.7%	80.6%	80.5%	(0.1%)	79.6%	79.8%	0.1%	78.7%
20			19.9%	21.3%	18.3%	19.4%	19.5%	0.1%	20.4%	20.2%	(0.1%)	21.3%
21			100.0%	100.0%	100.0%	100.0%	100.0%	-	100.0%	100.0%	-	100.0%
Deemed Equity												
22		10.0 L26	19,195.4	19,787.8	22,564.5	22,928.8	22,750.5	(178.3)	23,335.6	23,206.9	(128.7)	23,506.2
23		2.2 L40	(91.4)	(88.2)	(83.3)	(78.2)	(78.2)	0.0	(73.1)	(73.1)	0.0	(67.9)
24			51.6	69.2	63.8	65.5	90.4	24.9	67.3	91.8	24.5	93.1
25			250.0	250.0	250.0	250.0	250.0	0.0	250.0	250.0	0.0	250.0
26			19,405.5	20,018.7	22,795.1	23,166.1	23,012.7	(153.4)	23,579.8	23,475.6	(104.2)	23,781.3
27			30.0%	30.0%	30.0%	30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%
28			5,821.7	6,005.6	6,838.5	6,949.8	6,903.8	(46.0)	7,073.9	7,042.7	(31.3)	7,134.4
29			5,732.7	5,913.6	6,422.1	6,894.2	6,871.2	(23.0)	7,011.9	6,973.2	(38.6)	7,088.5
30			11.92%	11.57%	(6.67%)		10.26%			9.91%		
31						10.33%			10.15%			10.04%
32			683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
33			683.5	684.0	(428.224)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0

Return on Equity
(\$ million)

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BC Hydro
F22 RRARate Base
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Generation												
1		12.2 L13	6,501.3	6,706.0	8,876.3	8,953.8	8,994.9	41.1	9,168.9	9,159.9	(9.1)	9,149.4
2		11.0 L10	(2.8)	(2.5)	(2.6)	(2.3)	(2.3)	0.0	(2.1)	(2.0)	0.0	(1.8)
3		2.2 L7 x 90%	824.0	812.2	823.1	828.3	815.9	(12.4)	820.5	801.1	(19.4)	791.9
4			7,322.5	7,515.7	9,696.7	9,779.8	9,808.5	28.7	9,987.4	9,959.0	(28.4)	9,939.5
5			7,252.1	7,419.1	8,606.2	9,738.3	9,752.6	14.4	9,883.6	9,883.7	0.2	9,963.4
Transmission												
6		12.3 L12	6,764.0	6,946.3	7,243.3	7,301.7	7,207.2	(94.6)	7,293.2	7,254.5	(38.7)	7,453.6
7		11.0 L22	(536.3)	(537.5)	(294.6)	(303.7)	(301.4)	2.3	(303.5)	(302.1)	1.5	(305.1)
8		2.2 L7 x 5%	91.6	45.1	45.7	46.0	45.3	(0.7)	45.6	44.5	(1.1)	44.0
9			6,319.3	6,453.9	6,994.5	7,044.0	6,951.1	(92.9)	7,035.3	6,996.9	(38.4)	7,192.5
10			6,185.8	6,386.6	6,724.2	7,019.2	6,972.8	(46.5)	7,039.6	6,974.0	(65.6)	7,113.9
Distribution												
11		12.4 L12	5,194.3	5,425.2	5,644.8	5,913.5	5,880.0	(33.5)	6,208.2	6,160.4	(47.8)	6,406.0
12					0.0	(0.2)			(2.4)			
13		11.0 L33	(1,125.4)	(1,229.4)	(1,364.6)	(1,458.9)	(1,481.5)	(22.6)	(1,549.8)	(1,586.8)	(36.9)	(1,740.4)
14		2.2 L7 x 5%	0.0	45.1	45.7	46.0	45.3	(0.7)	45.6	44.5	(1.1)	44.0
15			4,068.9	4,240.9	4,326.0	4,500.4	4,443.8	(56.8)	4,701.6	4,618.1	(85.8)	4,709.7
16			4,006.5	4,154.9	4,283.4	4,413.2	4,384.9	(28.3)	4,601.0	4,531.0	(70.0)	4,705.6
Business Support												
17		12.1 L12	1,484.7	1,577.3	1,547.8	1,604.8	1,547.1	(57.7)	1,611.3	1,632.9	21.5	1,664.5
18					(0.5)	(0.2)			(0.0)			
19			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20			1,484.7	1,577.3	1,547.3	1,604.6	1,547.1	(57.5)	1,611.3	1,632.9	21.5	1,664.5
21			1,459.8	1,531.0	1,562.3	1,576.0	1,547.2	(28.8)	1,608.0	1,590.0	(18.0)	1,637.9
Total												
22		12.0 L13	19,944.3	20,654.8	23,312.2	23,773.9	23,629.1	(144.8)	24,281.7	24,207.6	(74.1)	24,673.5
23					(0.5)	(0.5)	0.0	0.5	(2.4)	0.0	2.4	0.0
24		11.0 L46	(1,664.5)	(1,769.5)	(1,661.8)	(1,764.9)	(1,785.3)	(20.3)	(1,855.4)	(1,890.9)	(35.5)	(2,047.3)
25		2.2 L7	915.6	902.5	914.5	920.3	906.6	(13.7)	911.7	890.1	(21.5)	879.9
26			19,195.4	19,787.8	22,564.5	22,928.8	22,750.5	(178.3)	23,335.6	23,206.9	(128.7)	23,506.2
27			18,904.2	19,491.6	21,176.1	22,746.7	22,657.5	(89.2)	23,132.2	22,978.7	(153.5)	23,420.9
Portion of Rate Base												
28			41.6%	41.3%	43.9%	46.0%	46.2%	0.2%	45.9%	46.2%	0.3%	45.7%
29			35.5%	35.6%	34.3%	33.2%	33.0%	(0.1%)	32.7%	32.6%	(0.1%)	32.7%
30			23.0%	23.1%	21.8%	20.8%	20.8%	(0.1%)	21.4%	21.2%	(0.2%)	21.6%
31			100.0%	100.0%	100.0%	100.0%	100.0%	-	100.0%	100.0%	-	100.0%

BC Hydro

F22 RRA

Contributions
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Contributions in Aid - Generation												
1			9.8	9.5	9.5	9.4	9.4	0.0	9.4	9.4	(0.0)	9.4
2					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3			(0.3)	0.0	0.4	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
4			0.0	(0.0)	(0.5)	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)
5			9.5	9.5	9.4	9.4	9.4	(0.0)	9.4	9.4	(0.0)	9.4
6			6.4	6.7	7.0	6.8	6.8	0.0	7.0	7.1	0.0	7.3
7			0.3	0.3	0.3	0.3	0.3	0.0	0.2	0.3	0.0	0.2
8			0.0	0.0	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9			6.7	7.0	6.8	7.0	7.1	0.0	7.3	7.3	0.0	7.6
10			2.8	2.5	2.6	2.3	2.3	(0.0)	2.1	2.0	(0.0)	1.8
Contributions in Aid - Transmission												
11			638.0	653.7	667.0	415.3	415.3	0.0	438.9	427.9	(11.0)	439.0
12					(256.6)	0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0
13			15.8	15.6	15.8	23.7	17.9	(5.8)	14.8	11.2	(3.6)	14.0
14			(0.1)	(2.3)	(11.0)	(0.1)	(4.6)	(4.4)	(0.2)	(0.1)	0.0	(0.1)
15			653.7	667.0	415.3	438.9	427.9	(11.0)	453.5	439.0	(14.5)	452.9
16			104.0	117.4	129.5	120.7	120.7	0.0	135.1	126.5	(8.7)	136.9
17					(14.8)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
18			13.5	14.0	14.4	14.4	14.8	0.3	14.8	14.7	(0.1)	10.9
19			(0.1)	(1.9)	(4.2)	0.0	(4.7)	(4.7)	0.0	0.0	0.0	0.0
20					(4.2)	0.0	(4.3)	(4.3)	0.0	(4.3)	(4.3)	0.0
21			117.4	129.5	120.7	135.1	126.5	(8.7)	150.0	136.9	(13.1)	147.8
22			536.3	537.5	294.6	303.7	301.4	(2.3)	303.5	302.1	(1.5)	305.1
Contributions in Aid - Distribution												
23			1,700.1	1,817.9	1,948.8	2,114.4	2,114.4	0.0	2,244.2	2,263.5	19.3	2,407.4
24					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25			122.9	140.6	168.8	134.0	160.9	26.9	133.7	148.5	14.8	200.2
26			(5.1)	(9.7)	(3.2)	(4.2)	(11.8)	(7.6)	(4.4)	(4.6)	(0.3)	(4.7)
27			1,817.9	1,948.8	2,114.4	2,244.2	2,263.5	19.3	2,373.5	2,407.4	33.8	2,602.8
28			660.8	692.5	719.3	749.8	749.8	0.0	785.3	782.0	(3.4)	820.6
29			33.4	35.4	37.9	40.6	40.4	(0.2)	43.5	43.8	0.2	47.0
30		2.2 L39	(0.7)	(3.2)	(4.9)	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)
31			(1.1)	(5.3)	(2.5)	0.0	(3.1)	(3.1)	0.0	0.0	0.0	0.0
32			692.5	719.3	749.8	785.3	782.0	(3.4)	823.7	820.6	(3.1)	862.5
33			1,125.4	1,229.4	1,364.6	1,458.9	1,481.5	22.6	1,549.8	1,586.8	36.9	1,740.4

BC Hydro

F22 RRA

Contributions

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Contributions in Aid - Total												
34		Gross Contns - Beginning of Year	2,347.8	2,481.1	2,625.3	2,539.0	2,539.0	0.0	2,692.5	2,700.8	8.3	2,855.7
35		IFRS Opening Balance Adjustment	0.0	0.0	(256.6)	0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0
36		Additions	138.4	156.2	185.0	157.8	178.8	21.0	148.5	159.7	11.2	214.2
37		Retirements & Transfers	(5.2)	(12.0)	(14.7)	(4.3)	(16.4)	(12.0)	(4.5)	(4.8)	(0.2)	(4.8)
38		Gross Contns - End of Year	2,481.1	2,625.3	2,539.0	2,692.5	2,700.8	8.3	2,836.4	2,855.7	19.3	3,065.1
39		Accum Amort - Beginning of Year	771.1	816.5	855.8	877.3	877.3	0.0	927.5	915.5	(12.0)	964.8
40		IFRS Opening Balance Adjustment	0.0	0.0	(14.8)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
41		Amortization	47.3	49.7	52.6	55.3	55.5	0.1	58.6	58.7	0.1	58.2
42		Amortization of Pre-96 CIAC	(0.7)	(3.2)	(4.9)	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)
43		Retirements & Transfers	(1.2)	(7.2)	(7.2)	0.0	(7.8)	(7.8)	0.0	0.0	0.0	0.0
44		IFRS amortization reclassification	0.0	0.0	(4.2)	0.0	(4.3)	(4.3)	0.0	(4.3)	(4.3)	0.0
45		Accum Amort - End of Year	816.5	855.8	877.3	927.5	915.5	(12.0)	981.0	964.8	(16.2)	1,017.8
46		Net Contributions - End of Year	1,664.5	1,769.5	1,661.8	1,764.9	1,785.3	20.3	1,855.4	1,890.9	35.5	2,047.3

BC Hydro

F22 RRA

Assets - Total (Excluding DSM and IPP Capital Leases)
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Assets in Service												
1	Opening Balance		22,245.4	23,579.6	25,029.3	24,956.3	24,956.3	0.0	26,303.4	26,123.6	(179.8)	27,605.2
2	Adjustment to Opening Balance		0.0	0.0	(3,509.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L21	1,468.6	1,543.7	3,553.1	1,391.0	1,236.1	(154.9)	1,459.0	1,528.3	69.3	1,445.2
4	Retirements & Transfers		(134.3)	(94.0)	(116.5)	(43.9)	(68.8)	(24.9)	(46.8)	(46.7)	0.0	(50.0)
5	Closing Balance		23,579.6	25,029.3	24,956.3	26,303.4	26,123.6	(179.8)	27,715.7	27,605.2	(110.4)	29,000.5
Accumulated Amortization												
6	Opening Balance		2,962.7	3,635.3	4,374.6	1,644.1	1,644.1	0.0	2,529.5	2,494.5	(35.0)	3,397.6
7	Adjustment to Opening Balance		0.0	0.0	(3,506.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		730.4	711.0	681.1	856.8	857.6	0.8	823.7	823.7	0.0	902.8
9	Amortization on Additions	13.0 L35	25.1	81.2	167.4	28.6	28.2	(0.4)	80.7	79.3	(1.4)	26.6
10	Accelerated Amort on Burrard		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Retirements & Transfers		(82.9)	(53.0)	(72.5)	0.0	(35.4)	(35.4)	0.0	0.0	0.0	0.0
12	Closing Balance		3,635.3	4,374.6	1,644.1	2,529.5	2,494.5	(35.0)	3,434.0	3,397.6	(36.4)	4,327.0
13	Net Assets in Service (Year-End)		19,944.3	20,654.8	23,312.2	23,773.9	23,629.1	(144.8)	24,281.7	24,207.6	(74.1)	24,673.5

BC Hydro

F22 RRA

Assets - Business Support

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Assets in Service												
1			2,036.1	2,203.6	2,457.2	1,920.1	1,920.1	0.0	2,167.0	2,083.0	(84.0)	2,355.8
2			0.0	0.0	(675.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3		13.0 L39	222.0	283.5	169.7	252.5	194.4	(58.1)	202.5	278.6	76.1	229.3
4			(54.6)	(29.8)	(31.5)	(5.5)	(31.5)	(25.9)	(5.6)	(5.8)	(0.2)	(6.0)
5			2,203.6	2,457.2	1,920.1	2,167.0	2,083.0	(84.0)	2,363.9	2,355.8	(8.1)	2,579.1
Accumulated Amortization												
6			601.1	718.9	880.0	372.3	372.3	0.0	562.2	535.9	(26.3)	722.9
7			0.0	0.0	(673.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8			159.3	157.7	144.0	174.0	173.4	(0.5)	149.0	148.5	(0.5)	179.6
9		13.0 L44	9.3	28.1	45.8	15.9	13.2	(2.8)	41.4	38.5	(2.9)	12.1
10			(50.8)	(24.7)	(23.9)	0.0	(23.0)	(23.0)	0.0	0.0	0.0	0.0
11			718.9	880.0	372.3	562.2	535.9	(26.3)	752.5	722.9	(29.6)	914.6
Net Assets in Service (Year-End)												
12			1,484.7	1,577.3	1,547.8	1,604.8	1,547.1	(57.7)	1,611.3	1,632.9	21.5	1,664.5

BC Hydro

F22 RRA

Assets - Generation

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Assets in Service												
1			7,249.3	7,561.3	7,955.0	9,304.7	9,304.7	0.0	9,643.1	9,682.3	39.2	10,119.5
2			0.0	0.0	(1,032.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3		13.0 L36	342.7	407.2	2,405.8	342.6	372.4	29.9	486.3	441.8	(44.6)	272.4
4			(30.6)	(13.5)	(23.3)	(4.1)	5.2	9.3	(4.4)	(4.6)	(0.2)	(4.4)
5			7,561.3	7,955.0	9,304.7	9,643.1	9,682.3	39.2	10,125.0	10,119.5	(5.5)	10,387.5
Accumulated Amortization												
6			880.6	1,060.1	1,249.0	428.4	428.4	0.0	689.3	687.4	(1.9)	959.6
7			0.0	0.0	(1,034.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8			191.0	182.6	173.8	256.7	257.2	0.5	253.7	257.6	3.9	275.3
9		13.0 L41	4.9	16.2	60.7	4.1	5.5	1.3	13.1	14.6	1.5	3.2
10			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11			(16.4)	(9.8)	(21.0)	0.0	(3.7)	(3.7)	0.0	0.0	0.0	0.0
12			1,060.1	1,249.0	428.4	689.3	687.4	(1.9)	956.1	959.6	3.5	1,238.1
13			6,501.3	6,706.0	8,876.3	8,953.8	8,994.9	41.1	9,168.9	9,159.9	(9.1)	9,149.4

BC Hydro

F22 RRA

Assets - Transmission

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Assets in Service												
1			7,226.1	7,695.0	8,086.0	7,697.4	7,697.4	0.0	7,984.1	7,886.5	(97.7)	8,162.3
2			0.0	0.0	(900.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3		13.0 L37	482.9	407.6	529.2	293.8	199.7	(94.1)	229.5	283.7	54.2	440.7
4			(14.0)	(16.6)	(17.9)	(7.0)	(10.6)	(3.6)	(7.3)	(7.8)	(0.5)	(7.7)
5			7,695.0	8,086.0	7,697.4	7,984.1	7,886.5	(97.7)	8,206.4	8,162.3	(44.1)	8,595.3
Accumulated Amortization												
6			730.6	931.0	1,139.7	454.0	454.0	0.0	682.4	679.3	(3.1)	907.9
7			0.0	0.0	(899.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8			200.7	195.9	190.7	225.9	227.0	1.2	223.1	222.2	(0.9)	228.7
9		13.0 L42	6.1	20.4	33.3	2.5	2.2	(0.3)	7.7	6.4	(1.2)	5.2
10			(6.5)	(7.5)	(10.7)	0.0	(4.0)	(4.0)	0.0	0.0	0.0	0.0
11			931.0	1,139.7	454.0	682.4	679.3	(3.1)	913.2	907.9	(5.3)	1,141.7
12			6,764.0	6,946.3	7,243.3	7,301.7	7,207.2	(94.6)	7,293.2	7,254.5	(38.7)	7,453.6

BC Hydro

F22 RRA

Assets - Distribution

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Gross Assets in Service												
1			5,733.8	6,119.7	6,531.0	6,034.2	6,034.2	0.0	6,509.1	6,471.9	(37.3)	6,967.6
2			0.0	0.0	(901.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3		13.0 L38	421.1	445.5	448.4	502.2	469.6	(32.6)	540.7	524.3	(16.4)	502.9
4			(35.1)	(34.2)	(43.8)	(27.2)	(31.9)	(4.7)	(29.5)	(28.5)	0.9	(31.9)
5			6,119.7	6,531.0	6,034.2	6,509.1	6,471.9	(37.3)	7,020.4	6,967.6	(52.8)	7,438.6
Accumulated Amortization												
6			750.4	925.4	1,105.8	389.4	389.4	0.0	595.6	591.9	(3.8)	807.2
7			0.0	0.0	(899.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8			179.5	174.8	172.6	200.3	200.0	(0.3)	198.0	195.5	(2.5)	219.3
9		13.0 L43	4.8	16.6	27.6	6.0	7.4	1.3	18.5	19.9	1.3	6.0
10			(9.3)	(11.0)	(16.9)	0.0	(4.8)	(4.8)	0.0	0.0	0.0	0.0
11			925.4	1,105.8	389.4	595.6	591.9	(3.8)	812.2	807.2	(4.9)	1,032.6
12			5,194.3	5,425.2	5,644.8	5,913.5	5,880.0	(33.5)	6,208.2	6,160.4	(47.8)	6,406.0

BC Hydro

F22 RRA

Capital Expenditures and Additions
(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Capital Expenditures												
1		Generation Growth	21.2	10.2	5.5	3.2	2.6	(0.6)	0.0	4.6	4.6	5.0
2		Generation - Waneta 2/3	0.0	0.0	1,218.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3		Generation Sustaining	563.6	534.0	364.7	341.8	302.5	(39.3)	435.5	346.6	(88.9)	383.4
4		Transmission Growth	247.4	280.5	224.3	185.0	159.6	(25.4)	198.9	101.2	(97.7)	142.9
5		Transmission Sustaining	268.1	218.3	193.0	222.6	223.3	0.7	286.5	270.3	(16.2)	325.6
6		Distribution Growth	226.0	287.6	296.0	299.9	339.7	39.8	284.6	343.2	58.6	306.7
7		Distribution Sustaining	224.5	235.2	206.7	187.6	176.2	(11.4)	176.9	175.9	(1.0)	219.3
8		Site C Project	662.7	704.8	1,116.7	1,530.0	1,619.1	89.1	1,535.5	1,626.0	90.5	1,361.0
9		Technology	76.5	71.2	84.3	95.6	133.0	37.4	56.0	71.2	15.2	69.2
10		Properties	86.6	63.5	48.4	58.9	56.4	(2.5)	55.3	65.1	9.8	75.6
11		Fleet & Other	58.9	59.6	58.3	63.6	59.0	(4.6)	75.1	82.0	6.9	70.3
12		Total	2,435.5	2,464.9	3,816.7	2,988.3	3,071.4	83.1	3,104.2	3,086.0	(18.2)	2,959.0
Total Capital Additions												
13		Generation	342.7	407.2	1,185.5	314.7	359.5	44.8	296.9	244.3	(52.7)	272.4
14		Generation - Waneta 2/3	0.0	0.0	1,220.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15		Transmission	482.9	407.6	529.2	293.8	199.7	(94.1)	229.5	283.7	54.2	440.7
16		Distribution	421.1	445.5	448.4	502.2	469.6	(32.6)	540.7	524.3	(16.4)	502.9
17		Site C Project	0.0	0.0	0.0	27.9	12.9	(15.0)	189.4	197.5	8.1	0.0
18		Technology	81.6	97.2	64.1	147.6	93.7	(53.9)	75.5	143.4	67.9	94.3
19		Properties	54.8	126.9	33.0	39.9	44.3	4.4	55.6	60.8	5.2	59.8
20		Fleet & Other	85.6	59.4	72.5	65.0	56.4	(8.6)	71.3	74.4	3.1	75.2
21		Total	1,468.6	1,543.7	3,553.1	1,391.0	1,236.1	(154.9)	1,459.0	1,528.3	69.3	1,445.2
Unfinished Construction												
22		Beginning of Year	2,460.8	3,412.9	4,306.8	4,553.3	4,553.3	0.0	6,150.7	6,373.4	222.8	7,931.1
23		Adjustments	(14.8)	(27.3)	(17.1)	0.0	(15.2)	(15.2)	0.0	0.0	0.0	0.0
24		Change in Unfinished	966.9	921.2	263.6	1,597.4	1,835.3	237.9	1,645.2	1,557.7	(87.5)	1,513.8
25		End of Year	3,412.9	4,306.8	4,553.3	6,150.7	6,373.4	222.8	7,795.8	7,931.1	135.3	9,444.9
26		Mid-Year Balance	2,936.9	3,859.9	4,430.1	5,352.0	5,463.4	111.4	6,973.2	7,152.3	179.0	8,688.0

BC Hydro

F22 RRA

Capital Expenditures and Additions
(\$ million)

		Reference			F2020			F2021			F2022
Line	Column	F2017 Actual	F2018 Actual	F2019 Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Amortization on Additions											
27	Generation	4.9	16.2	41.0	3.9	5.3	1.5	11.4	12.8	1.4	3.2
28	Generation - Waneta 2/3	0.0	0.0	19.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Transmission	6.1	20.4	33.3	2.5	2.2	(0.3)	7.7	6.4	(1.2)	5.2
30	Distribution	4.8	16.6	27.6	6.0	7.4	1.3	18.5	19.9	1.3	6.0
31	Site C Project	0.0	0.0	0.0	0.3	0.1	(0.2)	1.7	1.8	0.1	0.0
32	Technology	5.9	19.5	29.8	13.6	9.9	(3.7)	34.0	29.6	(4.5)	8.8
33	Properties	0.7	2.8	6.5	0.7	0.7	(0.0)	2.5	2.1	(0.4)	1.0
34	Fleet & Other	2.7	5.9	9.4	1.7	2.6	1.0	4.9	6.9	1.9	2.3
35	Total	25.1	81.2	167.4	28.6	28.2	(0.4)	80.7	79.3	(1.4)	26.6
Summary of Additions											
36	Generation	342.7	407.2	2,405.8	342.6	372.4	29.9	486.3	441.8	(44.6)	272.4
37	Transmission	482.9	407.6	529.2	293.8	199.7	(94.1)	229.5	283.7	54.2	440.7
38	Distribution	421.1	445.5	448.4	502.2	469.6	(32.6)	540.7	524.3	(16.4)	502.9
39	Business Support	222.0	283.5	169.7	252.5	194.4	(58.1)	202.5	278.6	76.1	229.3
40	Total	1,468.6	1,543.7	3,553.1	1,391.0	1,236.1	(154.9)	1,459.0	1,528.3	69.3	1,445.2
Summary of Amortization on Additions											
41	Generation	4.9	16.2	60.7	4.1	5.5	1.3	13.1	14.6	1.5	3.2
42	Transmission	6.1	20.4	33.3	2.5	2.2	(0.3)	7.7	6.4	(1.2)	5.2
43	Distribution	4.8	16.6	27.6	6.0	7.4	1.3	18.5	19.9	1.3	6.0
44	Business Support	9.3	28.1	45.8	15.9	13.2	(2.8)	41.4	38.5	(2.9)	12.1
45	Total	25.1	81.2	167.4	28.6	28.2	(0.4)	80.7	79.3	(1.4)	26.6
Composite Depreciation Rate											
46	Generation				2.45%			2.46%			2.38%
47	Transmission				1.70%			2.31%			2.34%
48	Distribution				2.40%			2.40%			2.40%
49	Site C Project				1.95%			1.27%			0.00%
50	Technology				18.38%			18.22%			18.68%
51	Properties				3.59%			3.73%			3.49%
52	Fleet & Other				5.08%			4.55%			6.05%

BC Hydro

F22 RRA

Domestic Energy Sales and Revenue

Line	Column	F2017	F2018	F2019	F2020			F2021			F2022
		Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Domestic Energy Sales (GWh)											
1	Residential	18,068	18,150	18,000	17,751	17,993	242	17,927	18,765	837	18,856
2	Light Industrial and Commercial	18,968	18,874	19,007	18,631	18,692	60	18,744	17,908	(836)	18,909
3	Large Industrial	13,176	13,433	13,874	13,527	13,383	(145)	13,203	12,033	(1,170)	12,982
4	Irrigation	80	79	79	97	72	(25)	99	73	(27)	79
5	Street Lighting	232	229	225	288	212	(76)	291	223	(68)	213
6	New Westminster & Tongass	464	466	463	585	465	(120)	591	481	(110)	497
7	Fortis	589	551	435	683	586	(97)	695	667	(28)	602
8	Seattle City Light	318	312	309	389	307	(82)	388	310	(78)	310
9	Liquefied Natural Gas	0	6	22	6	16	9	0	0	0	0
10	Other				0	205	205	0	0	0	0
11	Total	51,895	52,102	52,413	51,958	51,931	(27)	51,940	50,459	(1,481)	52,448
Domestic Revenues (\$ million)											
12	Residential	1,916.2	1,996.8	2,025.2	2,149.5	2,168.8	19.4	2,140.4	2,182.5	42.1	2,234.0
13	Light Industrial and Commercial	1,714.7	1,770.6	1,832.3	1,929.4	1,942.0	12.6	1,905.9	1,835.0	(70.9)	1,954.1
14	Large Industrial	732.6	771.2	829.6	875.7	848.4	(27.2)	852.2	731.1	(121.1)	842.3
15	Irrigation	6.0	5.4	6.3	7.9	6.4	(1.5)	7.8	6.9	(0.9)	6.9
16	Street Lighting	39.2	40.6	41.1	56.0	40.2	(15.8)	55.9	43.0	(12.9)	40.2
17	New Westminster & Tongass	27.7	28.9	29.7	40.2	31.8	(8.4)	39.9	31.5	(8.4)	33.6
18	Fortis	36.2	35.6	31.0	49.5	41.0	(8.5)	49.4	44.3	(5.0)	41.1
19	Seattle City Light	13.0	11.9	29.6	36.1	29.7	(6.4)	35.9	30.2	(5.7)	30.2
20	Liquefied Natural Gas	0.4	1.3	1.8	0.5	1.3	0.7	0.0	0.00	0.0	0.00
21	Other					5.4	5.4			0.0	
22	Subtotal	4,486.0	4,662.3	4,826.6	5,144.8	5,114.9	(29.8)	5,087.4	4,904.6	(182.9)	5,182.4
23	Revenue from Deferral Account Rate Rider	223.7	233.2	240.6	0.0	0.2	0.2	0.0	0.0	0.0	0.0
24	Total	4,709.7	4,895.5	5,067.2	5,144.8	5,115.1	(29.6)	5,087.4	4,904.6	(182.9)	5,182.4
25	Deferral Account Rate Rider	5.0%	5.0%	5.0%	0.0%	0.0%		0.0%	0.0%		0.0%
Average Revenues (\$/MWh)											
26	Residential	106.1	110.0	112.5	121.1	120.5	(0.6)	119.4	116.3	(3.1)	118.5
27	Light Industrial and Commercial	90.4	93.8	96.4	103.6	103.9	0.3	101.7	102.5	0.8	103.3
28	Large Industrial	55.6	57.4	59.8	64.7	63.4	(1.3)	64.5	60.8	(3.8)	64.9
29	Irrigation	75.0	67.6	80.3	81.9	88.9	7.0	78.1	95.2	17.1	87.4
30	Street Lighting	169.5	177.5	182.5	194.1	189.2	(4.9)	192.2	193.0	0.7	189.1
31	New Westminster & Tongass	59.7	61.9	64.3	68.8	68.3	(0.4)	67.5	65.5	(2.0)	67.6
32	Fortis	61.4	64.6	71.3	72.5	70.0	(2.5)	71.0	66.4	(4.6)	68.2
33	Seattle City Light	41.0	38.2	96.1	92.7	96.6	3.9	92.4	97.4	5.0	97.4
34	Liquefied Natural Gas	1,080.8	203.3	79.2	85.4	80.0	(5.5)	0.0	0.0	0.0	0.0
35	Other				0.0	26.1	26.1	0.0	0.0	0.0	0.0
36	Total (Excluding Misc Rev)	90.8	94.0	96.7	99.0	98.5	(0.5)	97.9	97.2	(0.7)	98.8

BC Hydro
F22 RRA
Domestic Energy Sales and Revenue

Line	Column	F2017	F2018	F2019	F2020			F2021			F2022
		Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Baseline											
37	COVID-19 Residential Grants to CCF				0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0
38	COVID-19 SGS Waivers to MCPP				0.0	0.0	0.0	0.0	(6.4)	(6.4)	0.0
39	Skagit and Ancillary Revenue to HDA				36.1	29.7	(6.4)	35.9	30.2	(5.7)	30.2
40	Load Variance				5,099.7	5,079.5	(20.3)	5,036.5	4,901.1	(135.5)	5,195.8
41	Biomass Energy Program Variance				9.0	5.8	(3.2)	15.2	16.9	1.7	15.9
42	Total				5,144.8	5,114.9	(29.8)	5,087.6	4,904.6	(183.1)	5,241.9

BC Hydro

F22 RRA

Miscellaneous Revenue

(\$ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Generation												
1	Amortization of Contributions	11.0 L7	0.3	0.3	0.3	0.3	0.3	0.0	0.2	0.3	0.0	0.2
2	Other		2.0	1.6	2.0	1.6	2.2	0.6	1.7	1.5	(0.2)	1.9
3	Total		2.3	1.9	2.3	1.9	2.5	0.6	1.9	1.7	(0.2)	2.2
Transmission												
4	External OATT	3.4 L74	11.8	11.4	15.4	15.9	10.7	(5.2)	15.9	12.9	(3.0)	11.1
5	FortisBC Wheeling Agreement		4.8	5.1	5.2	5.2	5.2	(0.0)	5.3	5.3	0.0	5.3
6	Secondary Revenue		7.6	7.5	8.7	6.0	7.1	1.2	6.2	6.9	0.7	7.1
7	Interconnections		3.6	2.9	4.9	2.2	6.4	4.2	2.2	4.6	2.4	2.3
8	Amortization of Contributions	11.0 L18:L19-L14	13.5	14.4	21.1	14.6	14.6	0.1	15.0	14.8	(0.2)	11.0
9	NTL Supplemental Charge		2.7	2.0	2.3	2.3	2.3	0.0	2.3	2.4	0.1	2.4
10	Total		44.1	43.3	57.6	46.1	46.4	0.3	46.8	46.8	(0.1)	39.2
Distribution												
11	Secondary Use Revenue & Other		15.3	15.9	20.9	14.1	17.0	2.8	14.1	15.8	1.7	16.9
12	Amortization of Contributions	11.0 L29:L31-L26	37.5	39.8	38.6	44.8	49.1	4.3	47.9	48.4	0.5	51.7
13	Total		52.7	55.7	59.5	58.9	66.0	7.1	62.0	64.2	2.2	68.6
Customer Care												
14	Meter/Trans Rents & Power Factor Surcharges		12.3	12.7	14.7	14.6	16.1	1.5	14.9	15.9	1.1	16.2
15	Smart Metering & Infrastructure Impact		4.5	3.8	3.3	2.1	2.2	0.1	1.7	1.5	(0.2)	1.5
16	Diversion Net Recoveries		0.5	0.4	0.2	0.1	0.2	0.1	0.1	0.1	0.0	0.1
17	Other Operating Recoveries		4.3	4.4	4.0	4.5	4.1	(0.3)	4.6	3.8	(0.8)	4.2
18	Customer Crisis Fund Rider Revenue		0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	0.0	0.5
19	Other		3.3	2.1	3.2	3.0	3.1	0.1	3.0	2.5	(0.5)	3.0
Waneta 2/3												
20	Lease revenue from Teck					75.2	75.2	0.0	76.7	76.7	0.0	78.2
21	Teck portion of operating costs				3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
22	Teck portion of water rentals				2.4	3.5	3.3	(0.2)	3.7	3.2	(0.5)	3.5
23	Teck portion of property taxes				0.1	0.6	0.9	0.3	0.6	0.8	0.2	0.8
24	Subtotal		0.0	0.0	6.3	84.9	84.7	(0.2)	86.9	86.6	(0.3)	88.6
25	Total		24.9	23.4	35.6	114.5	114.8	0.3	116.4	115.7	(0.8)	114.1
Business Support												
26	Corporate General Rents		4.6	4.3	4.1	3.7	3.9	0.2	3.8	2.9	(0.9)	3.6
27	Late Payment Charges		7.1	7.6	8.0	7.9	7.1	(0.8)	8.1	5.4	(2.7)	7.9
28	MMBU Secondary Revenue		5.8	5.9	3.9	3.8	3.9	0.1	3.8	3.2	(0.7)	3.3
29	Other		2.0	1.6	1.4	0.7	1.4	0.7	0.7	0.4	(0.3)	0.9
30	Total		19.5	19.4	17.4	16.1	16.4	0.2	16.4	11.9	(4.5)	15.8
31	Total Before Regulatory Accounts		143.4	143.7	172.5	237.5	246.0	8.5	243.6	240.2	(3.3)	239.9

BC Hydro

F22 RRA

Miscellaneous Revenue

(\$ million)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Deferral Account Additions												
32		Waneta 2/3										
33		Lease revenue from Teck			50.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34		Teck portion of capital expenditures			1.3	3.1	1.3	(1.8)	3.5	3.5	0.0	15.5
35		Subtotal	0.0	0.0	51.9	3.1	1.3	(1.8)	3.5	3.5	0.0	15.5
Regulatory Account Additions												
36		Smart Metering & Infrastructure Impact	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37		Minimum Reconnection Charge	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38		Subtotal	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39		Total Gross Miscellaneous Revenue	143.1	143.7	224.4	240.6	247.3	6.7	247.0	243.7	(3.3)	255.4
40		Transfers to NHDA	0.0	0.0	(51.9)	(3.1)	(1.3)	1.8	(3.5)	(3.5)	(0.0)	(15.5)
41		Transfers to Regulatory Accounts	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42		Total Current Miscellaneous Revenue	143.4	143.7	172.5	237.5	246.0	8.5	243.6	240.2	(3.3)	239.9

BC Hydro

F22 RRA

Full-Time Equivalents
(FTEs)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Integrated Planning												
1		Energy Planning and Analytics	29	31	38	44	45	1	44	44	(0)	44
2		Dam Safety	34	34	34	37	33	(5)	37	39	2	39
3		Stations Asset Planning	51	49	44	59	56	(3)	59	56	(3)	56
4		Line Asset Planning	124	127	131	131	133	2	131	131	(0)	144
5		Interconnections and Shared Assets	36	43	46	47	44	(3)	47	46	(1)	46
6		Engineering Design	436	432	420	457	457	1	457	446	(11)	408
7		Engineering Services	103	127	163	189	180	(9)	189	202	13	239
8		Business Unit Support	4	3	3	3	3	(0)	3	3	(0)	3
9		Total	820	845	880	967	950	(17)	967	967	(0)	980
Capital Infrastructure Project Delivery												
10		Project Delivery	324	387	408	450	418	(33)	450	432	(19)	431
11		Indigenous Relations	57	59	64	68	69	0	68	73	5	74
12		Environment	86	90	90	94	93	(1)	94	95	1	95
13		Properties	110	114	121	123	116	(6)	123	123	0	123
14		Business Unit Support	3	3	3	3	3	0	3	3	(0)	3
15		Total	581	652	686	739	699	(39)	739	726	(13)	726
Operations												
16		Program and Contract Management	205	206	219	228	251	23	228	274	46	280
17		Line Field Operations	822	841	858	922	876	(46)	922	924	1	924
18		Stations Field Operations	829	818	817	777	712	(65)	777	724	(53)	724
19		Distribution Design and Customer Connections	325	347	360	379	356	(23)	379	347	(32)	379
20		Construction Services	411	409	424	397	422	25	397	397	0	397
21		Generation System Operations	91	95	91	89	91	2	89	80	(9)	81
22		Transmission and Distribution System Operations	170	174	176	197	195	(2)	197	197	(0)	197
23		Business Unit Support	3	3	5	5	7	2	5	4	(1)	4
24		Total	2,855	2,893	2,951	2,995	2,910	(85)	2,995	2,947	(48)	2,985
Safety & Compliance												
25		Safety Systems and Assurance	48	49	46	52	48	(4)	52	51	(1)	46
26		Learning and Development	456	437	384	317	338	20	300	293	(7)	251
27		Field Safety Services	50	56	66	62	67	5	62	62	(0)	62
28		Security and Emergency Management	20	25	28	31	29	(2)	31	31	0	33
29		Reliability Compliance	3	4	5	5	6	1	5	7	2	22
30		Business Unit Support	2	2	2	2	2	0	2	2	0	3
31		Total	579	572	530	469	490	21	452	446	(6)	416

BC Hydro
F22 RRAFull-Time Equivalents
(FTEs)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Finance, Technology, Supply Chain												
32	Finance		194	196	199	206	203	(3)	206	211	5	211
33	Technology		186	226	264	269	269	(1)	269	273	4	283
34	Supply Chain		421	447	482	468	501	33	468	476	8	475
35	Business Unit Support		3	3	3	3	3	(0)	3	3	(0)	3
36	Total		805	871	947	946	975	29	946	963	17	972
People, Customer, Corporate Affairs												
37	Human Resources		84	88	117	124	123	(0)	124	126	2	126
38	Customer Service		154	191	438	479	483	4	479	484	5	492
39	Conservation and Energy Management		110	112	116	116	116	1	116	116	(0)	116
40	Communications and Community Engagement		94	95	105	107	103	(5)	107	108	1	108
41	Regulatory and Rates		21	22	24	23	24	1	23	23	0	23
42	Ethics and Merit Office		2	3	4	5	5	(0)	5	5	0	5
43	Smart Metering & Infrastructure		0	0	0	0	0	0	0	0	0	0
44	Business Unit Support		3	3	3	3	3	0	3	3	(0)	3
45	Total		469	513	806	856	857	0	856	864	8	872
Other												
46	Office of the General Counsel		36	35	36	42	39	(2)	41	41	0	41
47	Office of the President and Chief Executive Officer		4	3	3	3	3	0	3	3	(0)	3
48	Site C Project		167	226	322	460	445	(15)	472	497	26	504
49	Independent Power Producer Capital Leases		0	0	0	0	0	0	0	0	0	0
50	Corporate Costs		0	0	0	0	0	0	0	0	0	0
51	Capitalized Costs		0	0	0	0	0	0	0	0	0	0
52	Total		208	264	361	505	487	(17)	516	542	26	548
53	Total		6,315	6,611	7,161	7,477	7,369	(108)	7,471	7,455	(16)	7,500
Summary												
54	Regular Hour FTEs (excl. Smart Metering & Infrastructure & Site C Project)		5,578	5,791	6,257	6,461	6,330	(131)	6,449	6,439	(10)	6,446
55	Smart Metering & Infrastructure (SMI)		0	0	0	0	0	0	0	0	0	0
56	Site C Project		157	212	296	422	403	(19)	431	455	24	459
57	Subtotal Regular Hour FTEs		5,735	6,004	6,553	6,884	6,733	(150)	6,880	6,894	14	6,905
58	Overtime Hour FTEs (excl. Smart Metering & Infrastructure & Site C Project)		570	593	583	556	594	38	551	519	(32)	550
59	Smart Metering & Infrastructure (OT Hour FTEs)		0	0	0	0	0	0	0	0	0	0
60	Site C Project (OT Hour FTEs)		10	14	26	38	42	4	41	42	2	45
61	Total		6,315	6,611	7,161	7,477	7,369	(108)	7,471	7,455	(16)	7,500

BC Hydro

F22 RRA

Full-Time Equivalents
(FTEs)

Line	Column	Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	RRA	Actual	Diff	RRA	Forecast	Diff	Plan
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
Summary of FTE's by Function												
Regular Hour FTEs												
62	Operating		3,747	3,859	4,248	4,250	4,350	100	4,247	4,259	12	4,309
63	Capital		1,829	1,983	2,135	2,470	2,215	(255)	2,469	2,469	0	2,430
64	Deferred		160	161	169	164	168	4	164	166	2	166
65	Total		5,735	6,004	6,553	6,884	6,733	(150)	6,880	6,894	14	6,905
Overtime Hour FTEs												
66	Operating		336	350	360	220	360	141	219	229	11	235
67	Capital		243	256	247	373	274	(100)	373	332	(41)	360
68	Deferred		1	1	1	0	2	2	0	0	0	0
69	Total		580	607	609	593	636	42	592	561	(30)	595
Total FTEs by Function												
70	Operating		4,082	4,209	4,608	4,470	4,710	241	4,466	4,489	23	4,544
71	Capital		2,072	2,239	2,382	2,843	2,488	(355)	2,841	2,801	(41)	2,790
72	Deferred		161	162	171	164	170	6	164	166	2	166
73	Total		6,315	6,611	7,161	7,477	7,369	(108)	7,471	7,455	(16)	7,500

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix B Draft Orders



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ORDER NUMBER

G-xx-xx

IN THE MATTER OF

the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2022 Revenue Requirements Application

BEFORE:

Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

- A. On December 22, 2020, the British Columbia Hydro and Power Authority (**BC Hydro**) filed its Fiscal 2022 Revenue Requirements Application (**Application**) with the British Columbia Utilities Commission (**BCUC**) pursuant to sections 58 to 61 and 89 of the *Utilities Commission Act* (**UCA**), requesting, among other things:
- (i) Approval of an increase in rates by 1.16 per cent, effective April 1, 2021; and
 - (ii) Approval of the Fiscal 2022 Open Access Transmission Tariff (**OATT**) rates as set out in Table 9-4 of the Application, effective April 1, 2021;
- B. BC Hydro requests that these rate increases be set on an interim basis, pending a final BCUC decision on the Application;
- C. In its Application, BC Hydro also requested that certain information in Chapter 6, Appendix I and Appendix N be held confidential due to the customer-specific and/or commercially sensitive nature of the information and that all of Appendix Z be held confidential and be made available to the BCUC only due to the highly security sensitive nature of the information;
- D. By Order No. G-XX-21, the BCUC established the regulatory timetable for the review of the Application, which included one round of BCUC and intervener information requests and a review session, followed by a written argument phase; and
- E. The BCUC has commenced the review of the Application and BC Hydro's request that certain information in Chapter 6, Appendix I and Appendix N and all of Appendix Z be held confidential. The BCUC finds that the setting of interim rates is warranted. The BCUC will hold certain information in Chapter 6, Appendix I and Appendix N and all of Appendix Z confidential on an interim basis pending further review.

.../2

NOW THEREFORE, pursuant to sections 58 to 61 and 89 of the UCA, the BCUC orders as follows:

1. The requested rate increase of 1.16 per cent as applied for in the Application is approved on an interim basis effective April 1, 2021.
2. The requested OATT rates as set out in Table 9-4 of the Application are approved on an interim basis effective April 1, 2021.
3. The rates approved by this order will remain interim and subject to refund/recovery or adjustment with interest at BC Hydro's weighted average cost of debt until further order of the BCUC.
4. BC Hydro is to file with the BCUC for endorsement the applicable Tariff sheets reflecting the rates for fiscal 2022 shown in Table Y-1 and Table Y-2 of Appendix Y to the Application 30 days before the effective dates of the interim rates.
5. BC Hydro must provide all BC Hydro customers with notification of the interim rate changes as soon as is practical.
6. BC Hydro's request to hold certain information in Chapter 6, Appendix I and Appendix N and all of Appendix Z confidential is granted on an interim basis pending further review.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)

Commissioner

Attachment Options



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ORDER NUMBER

G-xx-xx

IN THE MATTER OF

the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2022 Revenue Requirements Application

BEFORE:

Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

- A. On December 22, 2020, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2022 Revenue Requirements Application (**Application**) with the British Columbia Utilities Commission (**BCUC**) pursuant to sections 44.2 and 58 to 61 of the *Utilities Commission Act* (**UCA**), requesting, among other things:
- (i) Approval of a general rate increase of 1.16 per cent, effective April 1, 2021; and
 - (ii) Approval of the Fiscal 2022 Open Access Transmission Tariff (**OATT**) rates as set out in Table 9-4 of the Application, effective April 1, 2021;
- B. In the Application, BC Hydro also requests the rate increase of 1.16 per cent and the requested OATT rates be set on an interim basis, effective April 1, 2021, pending a final BCUC decision on the Application;
- C. By Order No. G-XX-21, the BCUC approved, on an interim basis, the requested rate increase of 1.16 per cent, effective April 1, 2021 and the requested OATT rates for F2022, also effective April 1, 2021;
- D. By Order No. G-XX-21, the BCUC established the regulatory timetable for the review of the Application, which included one round of BCUC and intervener information requests and a review session, followed by a written argument phase; and
- E. The BCUC has considered the Application, the evidence, and submissions filed in the proceeding.

.../2

NOW THEREFORE, pursuant to sections 44.2 and 58 to 61 of the UCA, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The requested rate increase of 1.16 per cent as applied for in the Application is approved, effective April 1, 2021.
2. The following requests related to deferral and regulatory accounts are approved as follows:
 - (a) Cost of Energy Variance Accounts

The request to recover the balances in the Cost of Energy Variance Accounts through the Deferral Account Rate Rider (**DARR**) using the DARR table mechanism as described in Chapter 7, section 7.2.1 is approved. Specifically, starting in fiscal 2022 and on an ongoing basis, the DARR percentage effective April 1 of a given year is set based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year.

- (b) Amortization of Capital Additions Regulatory Account

The request to defer the variances arising in fiscal 2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account is approved. The interest charges and recovery of these amounts are on the same basis as previously approved for this account.

- (c) Dismantling Cost Regulatory Account

The request to continue to defer any variances between forecast and actual dismantling costs in fiscal 2022 to the Dismantling Cost Regulatory Account is approved. The interest applied to the balance of the account each year is based on BC Hydro's current weighted average cost of debt, and the forecast interest charged to the account each year is recovered from the account each year. The forecast account balance at the end of a test period is recovered over the next test period.

- (d) Project Write-Off Costs Regulatory Account

The request to recover the amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in fiscal 2022, and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts is approved. The interest to the balance of the account is applied based on BC Hydro's current weighted average cost of debt. The actual interest charged to the account for amounts related to any completed fiscal years is recovered over the next test period.

- (e) Electric Vehicle Costs Regulatory Account

The request to establish an Electric Vehicle Costs Regulatory Account to defer actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the Greenhouse Gas Reduction (Clean Energy) Regulation for fiscal 2020 and fiscal 2021 is approved. The interest to the balance of the account is based on BC Hydro's current weighted average cost of debt and the forecast interest charged to the account each year is recovered from the account each year. Starting in fiscal 2022, the forecast balance at the end of a test period is recovered over the next test period, until such time that the actual amounts deferred to the account for fiscal 2020 and fiscal 2021 are recovered in rates.

(f) Rock Bay Remediation Regulatory Account

The request to close the Rock Bay Remediation Regulatory Account at the end of fiscal 2022 is approved.

3. The requested depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2022, as set out in Table 8-2 of the Application, are approved.
4. The request to amortize the assets within the infrastructure rights asset class over a 35-year useful life as set out in section 8.2.2 of the Application is approved.
5. The requested OATT rates as set out in Table 9-4 of the Application are approved, effective April 1, 2021.
6. The requested demand-side management expenditure schedule of \$82.2 million for fiscal 2022 is accepted.
7. Within 30 days of the date of this Order, BC Hydro is to file the applicable Tariff sheets reflecting the rates for fiscal 2022 shown in Table Y-1 and Table Y-2 of Appendix Y to the Application.
8. The request to hold certain information in Chapter 6, Appendix I and Appendix N and all of Appendix Z confidential is granted.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix C

Electric Vehicle Charging Stations as Prescribed Undertakings

Information on BC Hydro Fast Charging Stations

Municipality/Location	Station Name	Physical Address	Region	In-ServideDate	Status	Expansion* of Existing Site	Limited Municipality	Population (Stats Canada)	Site Limit (Population / 9,000)	# of BC Hydro Sites	# of Stations	Charging Capacity (kW)	# of Charging Ports	Maximum # of Vehicles Charge at a Time	Notes
Surrey	Surrey - Powertech Labs	12388 88 Ave. Surrey, BC	Metro Vancouver	13-Jul-2013	To be Decommissioned		Yes	584,526	65	1	1	50	2	1	To be decommissioned March 31, 2021
Nanaimo	Nanaimo - Conference Centre	101 Gordon St, Nanaimo, BC	Vancouver Island	23-Aug-2013	Complete		Yes	99,856	11	1	1	50	2	1	Equipment Leasing
Duncan	Duncan - Island Savings Centre	2680 James St, Duncan, BC	Vancouver Island	19-Oct-2013	Complete		No	5,342	n/a	1	1	50	2	1	Equipment Leasing
Kamloops	Kamloops - Hillside Stadium	910 McGill Rd Kamloops, BC	Southern Interior	27-Jan-2014	Complete		Yes	100,046	11	1	1	50	2	1	Equipment Leasing
North Vancouver, City of	North Vancouver - 1st & Lonsdale	140 1st St E North Vancouver, BC	Metro Vancouver	23-Sep-2014	Complete		Yes	57,325	6	1	1	50	2	1	
Sechelt District Municipality	Sechelt - Trail Bay Mall	5755 Cowrie Street, Sechelt, BC	Non-Metro / Fraser Valley	15-Dec-2014	Complete		Yes	10,809	1	1	1	50	2	1	
Saanich	Saanich Uptown	3440 Saanich Road, Victoria, BC	Vancouver Island	9-Jan-2015	Decommissioned		Yes	122,173	14	0	0				Decommissioned on March 20, 2020
Abbotsford	Abbotsford - EcoDairy	1356 Sumas Way Abbotsford, BC	Non-Metro / Fraser Valley	5-Mar-2015	Complete		Yes	158,457	18	1	1	50	2	1	Equipment Leasing
Revelstoke	Revelstoke	301 Victoria Rd, Revelstoke, BC	Southern Interior	15-Mar-2015	Complete		No	8,259	n/a	1	1	50	2	1	
Langley, District Municipality	Langley Events Centre	7888 200 Street Langley, BC	Non-Metro / Fraser Valley	2-Apr-2015	Complete		Yes	130,924	15	1	1	50	2	1	Equipment Leasing
Merritt	Merritt Visitor Information Centre	2202 Voght St Merritt, BC	Southern Interior	1-May-2015	Complete		No	7,722	n/a	1	1	50	2	1	
Penticton	Penticton	234 Main St Penticton, BC	Southern Interior	7-Jul-2015	Decommissioned		Yes	36,425	4	0	0				Decommissioned on October 1, 2020
Hope	Hope	839 4 Ave, Hope, BC	Non-Metro / Fraser Valley	30-Oct-2015	Complete		No	6,667	n/a	1	1	50	2	1	
Keremeos	Keremeos	702 4 St, Keremeos, BC	Southern Interior	9-Nov-2015	Complete		No	1,692	n/a	1	1	50	2	1	
Salmon Arm	Salmon Arm	381 Ross St Salmon Arm, BC	Southern Interior	18-Nov-2015	Complete		Yes	19,115	2	1	1	50	2	1	
Colwood	Colwood - Park and Ride	1830 Old Island Hwy, Colwood, BC	Vancouver Island	16-Dec-2015	Complete		Yes	18,867	2	1	1	50	2	1	
Boston Bar	Boston Bar - Canyon Lanes	47585 Trans Canada Hwy., Boston Bar, BC	Southern Interior	1-Jan-2016	Complete		No	190	n/a	1	1	50	2	1	
Whistler	Whistler	4010 Whistler Way, Whistler, BC	Non-Metro / Fraser Valley	12-Jan-2016	Complete		Yes	13,763	2	1	1	50	2	1	Equipment Leasing
Spences Bridge	Spences Bridge	3633 Station St, Spences Bridge, BC	Southern Interior	9-Feb-2016	Complete		No	99	n/a	1	1	50	2	1	Equipment Leasing
West Kelowna	West Kelowna	3678 Brown Rd, West Kelowna/BC	Southern Interior	1-Jun-2016	Complete		Yes	35,818	4	1	1	50	2	1	Equipment Leasing
Chase	Chase	400 Shuswap Ave, Chase/BC	Southern Interior	10-Jun-2016	Complete		No	2,478	n/a	1	1	50	2	1	
Princeton	Princeton	114 Tipton Ave, Princeton, BC	Southern Interior	30-Jun-2016	Complete		No	2,988	n/a	1	1	50	2	1	
Chilliwack	Chilliwack	45950 Cheam Ave, Chilliwack, BC	Non-Metro / Fraser Valley	1-Jul-2016	Complete		Yes	94,534	11	1	1	50	2	1	
Manning Park	Manning Park	7500 BC-3, Manning Park, BC	Southern Interior	31-Jul-2016	Complete		No	n/a	n/a	1	1	50	2	1	
Vernon	Vernon	3004 32nd Ave, Vernon/BC	Southern Interior	1-Sep-2016	Complete		Yes	43,315	5	1	1	50	2	1	Equipment Leasing
Surrey	Surrey Central City Hall	13450 104 Avenue, Surrey, BC	Metro Vancouver	25-Oct-2016	Decommissioned		Yes	584,526	65	0	0				Decommissioned on Sept 30, 2020
Malakwa	Malakwa Supermarket	4270 Oxbow Frontage Rd, Malakwa, BC	Southern Interior	31-Oct-2016	Complete		No	559	n/a	1	1	50	2	1	
Squamish	Squamish	37950 2nd Ave. Squamish BC	Non-Metro / Fraser Valley	1-Nov-2016	Complete		Yes	20,404	2	1	1	50	2	1	
Cranbrook	Cranbrook	38 Cranbrook St N, Cranbrook, BC	Kootenays	6-Apr-2017	Complete		Yes	21,247	2	1	1	50	2	1	Constructed by Community Energy Association
Canal Flats	Canal Flats - Columbia Discovery Centre	4925 Burns Ave, Canal Flats, BC	Kootenays	11-Dec-2017	Complete		No	723	n/a	1	1	50	2	1	Constructed by Community Energy Association
Radium Hot Springs	Radium Community Centre	4863 Stanley St, Radium Hot Springs, BC	Kootenays	11-Dec-2017	Complete		No	811	n/a	1	1	50	2	1	Constructed by Community Energy Association
Jaffray	Jaffray Pump & Pantry	7311 Bertrand Rd., Jaffray, BC	Kootenays	25-Jan-2018	Complete		No	554	n/a	1	1	50	2	1	Constructed by Community Energy Association
Ucluelet	Ucluelet - Pacific Rim Visitor's Centre	2791 Pacific Rim Hwy, Ucluelet, BC	Vancouver Island	9-Apr-2018	Complete		No	1,842	n/a	1	1	50	2	1	
Port Alberni	Port Alberni - No Frills	3455 Johnston Road, Port Alberni, BC	Vancouver Island	16-Apr-2018	Complete		Yes	18,751	2	1	1	50	2	1	
Nanaimo	Nanaimo - Superstore	6435 Metral Drive, Nanaimo, BC	Vancouver Island	17-Apr-2018	Complete		Yes	99,856	11	1	1	50	2	1	
Richmond	Richmond - Superstore	4651 No. 3 Road, Richmond, BC	Metro Vancouver	18-Apr-2018	Complete		Yes	212,276	24	1	1	50	2	1	
Surrey	Surrey - South Superstore	2332 160 St., Surrey, BC	Metro Vancouver	18-Apr-2018	Complete		Yes	584,526	65	1	1	50	2	1	
Vancouver	Vancouver - Grandview Hwy Superstore	3185 Grandview Highway, Vancouver, BC	Metro Vancouver	18-Apr-2018	Complete		Yes	685,885	76	1	1	50	2	1	
Qualicum Beach	Qualicum - Quality Foods	133 West Fern, Qualicum, BC	Vancouver Island	19-Apr-2018	Complete		Yes	9,166	1	1	1	50	2	1	
Coquitlam	Coquitlam - Superstore West	1301 Lougheed Hwy, Coquitlam, BC	Metro Vancouver	20-Apr-2018	Complete		Yes	149,894	17	1	1	50	2	1	
Vancouver	UBC - Wesbrook Place	6163 University Blvd, Vancouver, BC	Metro Vancouver	23-Apr-2018	Complete		Yes	685,885	76	1	1	50	2	1	
Campbell River	Campbell River - Community Centre	401 11 Ave, Campbell River	Vancouver Island	1-May-2018	Complete		Yes	35,849	4	1	1	50	2	1	
Courtenay	Courtenay - Superstore	757 Ryan Road, Courtenay, BC	Vancouver Island	1-May-2018	Complete		Yes	28,216	3	1	1	50	2	1	
Coquitlam	Coquitlam - Superstore East	3000 Lougheed Hwy, Coquitlam, BC	Metro Vancouver	11-May-2018	Complete		Yes	149,894	17	1	1	50	2	1	
Sidney	Sidney	2330 Bevan Avenue, Sidney, BC	Vancouver Island	25-May-2018	Complete		Yes	12,235	1	1	1	50	2	1	
Vancouver	Vancouver - Homer St	561 Homer Street, Vancouver, BC	Metro Vancouver	25-May-2018	Complete		Yes	685,885	76	1	2	50	4	2	
West Vancouver	West Vancouver - Horseshoe Bay	6400 Bruce Street, District of West Vancouver, BC	Metro Vancouver	25-May-2018	Complete		Yes	43,945	5	1	1	50	2	1	
Mission	Mission Superstore	32136 Lougheed Highway, Mission, BC	Non-Metro / Fraser Valley	29-May-2018	Complete		Yes	43,202	5	1	1	50	2	1	
Sparwood	Sparwood	100 Centennial St, Sparwood, BC	Kootenays	5-Jun-2018	Complete		No	4,032	n/a	1	1	50	2	1	Constructed by Community Energy Association
Britton Creek	Britton Creek Rest Area	Exit 228 at Coquihalla Lakes Rd, BC	Southern Interior	13-Jun-2018	Complete		No	n/a	n/a	1	2	50	4	2	
Golden	Golden	820 9 Ave South, Golden, BC V0A 1H0	Kootenays	30-Jun-2018	Complete		No	4,057	n/a	1	1	50	2	1	Constructed by Community Energy Association
Surrey	Surrey Tynehead Gas Station	16815 - 96th Ave, Surrey, BC	Metro Vancouver	17-Jul-2018	Complete		Yes	584,526	65	1	1	50	2	1	
Vancouver	Vancouver - Kerrisdale	5356 West Boulevard, Vancouver, BC	Metro Vancouver	11-Aug-2018	Complete		Yes	685,885	76	1	1	50	2	1	
Rogers Pass	Rogers Pass Discovery Centre	9520 Trans Canada Hwy, Rogers Pass, BC	Kootenays	18-Dec-2018	Complete		No	n/a	n/a	1	1	50	2	1	Constructed by Community Energy Association
Vancouver	Vancouver - SE Marine Drive Superstore	350 South East Marine Drive, Vancouver, BC	Metro Vancouver	31-Dec-2018	Complete		Yes	685,885	76	1	1	50	2	1	
Field	Field - Yoho National Park	Field, BC - Yoho National Park Visitors Centre	Kootenays	15-Jan-2019	Complete		No	230	n/a	1	1	50	2	1	Constructed by Community Energy Association
Surrey	Surrey - Cloverdale	5771 176A St, Surrey BC	Metro Vancouver	31-Jan-2019	Complete		Yes	584,526	65	1	1	50	2	1	
Vancouver	Vancouver - SE Marine Superstore (Expansion)*	350 South East Marine Drive, Vancouver, BC	Metro Vancouver	2-Jul-2019	Complete	Yes	Yes	685,885	76	0	1	50	2	1	
70 Mile House	70 Mile House	1597 BC-97, 70 Mile House, BC	Southern Interior	19-Jul-2019	Complete		No	1,075	n/a	1	1	50	2	1	
Cache Creek	Cache Creek	1270 Stage Rd, Cache Creek, BC	Southern Interior	19-Jul-2019	Complete		No	1,052	n/a	1	1	50	2	1	
Clinton	Clinton	1423 BC-97, Clinton, BC	Southern Interior	19-Jul-2019	Complete		No	659	n/a	1	1	50	2	1	
Coquitlam	Coquitlam - Superstore East (Expansion)	3000 Lougheed Hwy, Coquitlam, BC	Metro Vancouver	21-Aug-2019	Complete	Yes	Yes	149,894	17	0	1	50	2	1	
Richmond	Richmond - Superstore (Expansion)	4651 No. 3 Road, Richmond, BC	Metro Vancouver	17-Sep-2019	Complete	Yes	Yes	212,276	24	0	1	50	2	1	
Surrey	Surrey - South Superstore (Expansion)	2332 160 St., Surrey, BC	Metro Vancouver	30-Sep-2019	Complete	Yes	Yes	584,526	65	0	1	50	2	1	
Saanich	Saanich	3544 Blanshard Street, Victoria, BC V8X 1W3	Vancouver Island	9-Oct-2019	Complete		Yes	122,173	14	1	2	50	4	2	
Port Hardy	Port Hardy	7360 Columbia Street, Port Hardy V0N 2P0	Vancouver Island	10-Oct-2019	Complete		No	4,315	n/a	1	1	50	2	1	
Blue River	Blue River	Blue River V0E 1J0	Northern Interior	16-Oct-2019	Complete		No	157	n/a	1	1	50	2	1	
Valemount	Valemount	735 Cranberry Lake Road, Valemount V0E 2Z0	Northern Interior	17-Oct-2019	Complete		No	1,128	n/a	1	1	50	2	1	
McBride	McBride	100 Robson Centre, McBride, British Columbia	Northern Interior	18-Oct-2019	Complete		No	666	n/a	1	1	50	2	1	
Sechelt District Municipality	Madeira Park	12808 Madeira Park Rd, Madeira Park, BC V0N 2H1	Non-Metro / Fraser Valley	31-Oct-2019	Complete		Yes	10,809	1	1	1	50	2	1	
Colwood	Colwood (Expansion)	1830 Old Island Hwy, Colwood, BC	Vancouver Island	1-Nov-2019	Complete	Yes	Yes	18,867	2	0	1	50	2	1	
North Vancouver, City of	North Vancouver (Expansion)	140 1st St E North Vancouver, BC	Metro Vancouver	6-Nov-2019	Complete	Yes	Yes	57,325	6	0	1	50	2	1	
Hope	Hope (Expansion)	839 4 Ave, Hope, BC	Non-Metro / Fraser Valley	9-Nov-2019	Complete	Yes	No	6,667	n/a	0	1	25			
Delta	South Delta/Tsawwassen	1406 Tsawwassen Dr S, Tsawwassen V4M 4G2,	Metro Vancouver	22-Nov-2019	Complete		Yes	109,490	12	1	1	50	2	1	

Information on BC Hydro Fast Charging Stations

Municipality/Location	Station Name	Physical Address	Region	In-ServideDate	Status	Expansion* of Existing Site	Limited Municipality	Population (Stats Canada)	Site Limit (Population / 9,000)	# of BC Hydro Sites	# of Stations	Charging Capacity (kW)	# of Charging Ports	Maximum # of Vehicles Charge at a Time	Notes
Powell River	Powell River	5001 Joyce Avenue, Powell River	Non-Metro / Fraser Valley	5-Dec-2019	Complete		Yes	13,829	2	1	1	50	2	1	
Quesnel	Quesnel	2335 Maple Dr, Quesnel V2J6J6	Northern Interior	15-Jan-2020	Complete		Yes	10,392	1	1	1	50	2	1	
Hixon	Hixon	367 Von Lienen Road, Hixon V0K 1S0	Northern Interior	15-Jan-2020	Complete		No	277	n/a	1	1	50	2	1	
Williams Lake	Williams Lake	450 Mart Street, Williams Lake	Northern Interior	30-Jan-2020	Complete		Yes	11,359	1	1	1	50	2	1	
Nanaimo	Nanaimo (Expansion)	6435 Metral Drive, Nanaimo, BC	Vancouver Island	20-Mar-2020	Complete	Yes	Yes	99,856	11	0	1	50	2	1	
Sidney	Sidney (Expansion)	2330 Bevan Avenue, Sidney, BC	Vancouver Island	20-Mar-2020	Complete	Yes	Yes	12,235	1	0	1	50	2	1	
Port Alberni	Port Alberni (Expansion)	3455 Johnston Road, Port Alberni, BC	Vancouver Island	30-Apr-2020	Complete	Yes	Yes	18,751	2	0	1	50	2	1	
Chilliwack	Chilliwack (Expansion)	45950 Cheam Ave, Chilliwack, BC	Non-Metro / Fraser Valley	8-Jun-2020	Complete	Yes	Yes	94,534	11	0	1	50	2	1	
Campbell River	Campbell River (Expansion)	401 11 Ave, Campbell River	Vancouver Island	12-Jun-2020	Complete	Yes	Yes	35,849	4	0	1	50	2	1	
Courtenay	Courtenay (Expansion)	757 Ryan Road, Courtenay, BC	Vancouver Island	12-Jun-2020	Complete	Yes	Yes	28,216	3	0	1	50	2	1	
Port McNeill	Port McNeill	1594 Beach Drive, Port McNeill	Vancouver Island	12-Jul-2020	Complete		No	2,395	n/a	1	1	50	2	1	
Coquitlam	Coquitlam - Superstore West (Expansion)	1356 Sumas Way Abbotsford, BC	Non-Metro / Fraser Valley	17-Sep-2020	Complete	Yes	Yes	149,894	17	0	1	50	2	1	
Vancouver	Grandview Hwy - Superstore (Expansion)	140 1st St E North Vancouver, BC	Metro Vancouver	21-Sep-2020	Complete	Yes	Yes	685,885	76	0	1	50	2	1	
Prince George	Prince George	2155 Ferry Avenue, Prince George V2N 5E8	Northern Interior	1-Dec-2020	Incomplete		Yes	81,345	9	1	2	50	4	2	
Burns Lake	Burns Lake	TBC - 313 Highway 16 W, Burns Lake	Northern BC	1-Dec-2020	Incomplete		No	1,871	n/a	1	2	50	4	2	
Victoria	Victoria	TBC - 810 Blanshard St, Victoria	Vancouver Island	31-Mar-2021	Incomplete		Yes	94,005	10	1	2	50	4	2	
Sechelt District Municipality	Sechelt (Expansion)	5755 Cowrie Street, Sechelt, BC	Vancouver Island	31-Mar-2021	Incomplete	Yes	Yes	10,809	1	0	1	50	2	1	
Surrey	Surrey - Cloverdale (Expansion)	5771 176A St, Surrey BC	Metro Vancouver	31-Mar-2021	Incomplete	Yes	Yes	584,526	65	0	1	50	2	1	
Vancouver	UBC - Wesbrook Place (Expansion)	6163 University Blvd, Vancouver, BC	Metro Vancouver	31-Mar-2021	Incomplete	Yes	Yes	685,885	76	0	1	50	2	1	
Vancouver	Vancouver - Kerrisdale (Expansion)	5356 West Boulevard, Vancouver, BC	Metro Vancouver	31-Mar-2021	Incomplete	Yes	Yes	685,885	76	0	1	50	2	1	
West Vancouver	District of West Vancouver (Expansion)	6400 Bruce Street, District of West Vancouver, BC	Metro Vancouver	31-Mar-2022	Incomplete	Yes	Yes	43,945	5	0	1	50	2	1	
Whistler	Whistler (Expansion)	4010 Whistler Way, Whistler, BC	Non-Metro / Fraser Valley	31-Mar-2021	Incomplete	Yes	Yes	13,763	2	0	1	50	2	1	
Harrison Hot Springs	Seabird Island	77 Lougheed Highway, Sqewgel Gas Bar and Convenience	Non-Metro / Fraser Valley	31-Mar-2022	Incomplete		No	1,632	n/a	1	2	50	4	2	
Spences Bridge	Spences Bridge (Expansion)	3633 Station St, Spences Bridge, BC	Southern Interior	31-Mar-2022	Incomplete	Yes	No	99	n/a	0	1	50	2	1	
Vernon	Vernon (Expansion)	3004 32nd Ave, Vernon BC	Southern Interior	31-Mar-2022	Incomplete	Yes	Yes	43,315	5	0	1	50	2	1	
Fraser Lake	Fraser Lake	TBC - 30 Carrier Crescent, Fraser Lake	Northern BC	31-Mar-2022	Incomplete		No	973	n/a	1	2	50	4	2	
Gold River	Gold River	TBC - 375 Nimpkish Dr, Gold River	Vancouver Island	31-Mar-2022	Incomplete		No	1,299	n/a	1	2	50	4	2	
Houston	Houston	TBC - 3289 Highway 16, Houston	Northern BC	31-Mar-2022	Incomplete		No	3,106	n/a	1	2	50	4	2	
Kitimat	Kitimat	TBC - 276 City Centre, Kitimat	Northern BC	31-Mar-2022	Incomplete		No	8,200	n/a	1	2	50	4	2	
Lillooet	Lillooet	TBC - 615 Main Street, Lillooet	Non-Metro / Fraser Valley	31-Mar-2022	Incomplete		No	2,249	n/a	1	2	50	4	2	
Maple Ridge	Maple Ridge	TBC - 22441 Dewdney Trunk Rd #102, Maple Ridge	Non-Metro / Fraser Valley	31-Mar-2022	Incomplete		Yes	91,222	10	1	2	50	4	2	
Mcleod Lake	Mcleod Lake	TBC - 1 Carp Lake Rd, Mcleod Lake	Northern BC	31-Mar-2022	Incomplete		No	87	n/a	1	1	50	2	1	
New Hazelton	New Hazelton	TBC - 4633 10th Ave, New Hazelton	Northern BC	31-Mar-2022	Incomplete		No	604	n/a	1	2	50	4	2	
Burnaby	North Burnaby	TBC - 490 Sperling Avenue, North Burnaby	Metro Vancouver	31-Mar-2022	Incomplete		Yes	253,007	28	1	2	50	4	2	
Pemberton	Pemberton	TBC - 7452 Frontier Street, Pemberton	Non-Metro / Fraser Valley	31-Mar-2022	Incomplete		No	2,951	n/a	1	2	50	4	2	
Prince Rupert	Prince Rupert	TBC - 900, Wilson Ave, Prince Rupert	Northern BC	31-Mar-2022	Incomplete		Yes	13,054	1	1	2	50	4	2	
Smithers	Smithers	TBC - 3743 Second Avenue, Smithers	Northern BC	31-Mar-2022	Incomplete		No	5,670	n/a	1	2	50	4	2	
Terrace	Terrace	TBC - 14309 BC-16, Terrace, BC V8G 0A6	Northern BC	31-Mar-2022	Incomplete		Yes	12,594	1	1	2	50	4	2	
Vanderhoof	Vanderhoof	TBC - Ryley Lane, Vanderhoof	Northern BC	31-Mar-2022	Incomplete		No	4,668	n/a	1	2	50	4	2	
Duncan	Duncan (Expansion)	291 Cowichan Way, Duncan, BC V9L 4T8	Vancouver Island	31-Mar-2022	Incomplete	Yes	No	5,342	n/a	0	1	50	2	1	
Cranbrook	Cranbrook (Expansion)	38 Cranbrook St N, Cranbrook, BC	Kootenays	31-Mar-2022	Incomplete	Yes	Yes	21,247	2	0	1	50	2	1	
Nanaimo	Nanaimo - Conference Centre (Expansion)	101 Gordon St, Nanaimo, BC	Vancouver Island	31-Mar-2022	Incomplete	Yes	Yes	99,856	11	0	1	50	2	1	
Merritt	Merritt Visitor Information Centre (Expansion)	2202 Voght St Merritt, BC	Southern Interior	31-Mar-2022	Incomplete	Yes	No	7,722	n/a	0	1	50	2	1	
Manning Park	Manning Park (Expansion)	7500 BC-3, Manning Park, BC	Southern Interior	31-Mar-2022	Incomplete	Yes	No	n/a	n/a	0	1	50	2	1	
West Kelowna	West Kelowna (Expansion)	3678 Brown Rd, West Kelowna BC	Southern Interior	31-Mar-2022	Incomplete	Yes	Yes	35,818	4	0	1	50	2	1	
Salmon Arm	Salmon Arm (Expansion)	381 Ross St Salmon Arm, BC	Southern Interior	31-Mar-2022	Incomplete	Yes	Yes	19,115	2	0	1	50	2	1	
70 Mile House	70 Mile House (Expansion)	1597 BC-97, 70 Mile House, BC	Southern Interior	31-Mar-2022	Incomplete	Yes	No	1,075	n/a	0	1	50	2	1	
Blue River	Blue River (Expansion)	Blue River V0E 1J0	Northern Interior	31-Mar-2022	Incomplete	Yes	No	157	n/a	0	1	50	2	1	
Cache Creek	Cache Creek (Expansion)	1270 Stage Rd, Cache Creek, BC	Southern Interior	31-Mar-2022	Incomplete	Yes	No	1,052	n/a	0	1	50	2	1	
Kamloops	Kamloops - Hillside Stadium (Expansion)	910 McGill Rd Kamloops, BC	Southern Interior	31-Mar-2022	Incomplete	Yes	Yes	100,046	11	0	1	50	2	1	
Mcleod Lake	Mcleod Lake (Expansion)	1 Carp Lake Rd, Mcleod Lake, BC	Northern Interior	31-Mar-2022	Incomplete	Yes	No	87	n/a	0	1	50	2	1	
Sechelt District Municipality	Madeira Park (Expansion)	12808 Madeira Park Rd, Madeira Park, BC V0N 2H1	Non-Metro / Fraser Valley	31-Mar-2022	Incomplete	Yes	Yes	10,809	1	0	1	50	2	1	
McBride	McBride (Expansion)	100 Robson Centre, McBride, British Columbia	Northern Interior	31-Mar-2022	Incomplete	Yes	No	666	n/a	0	1	50	2	1	
Port Hardy	Port Hardy (Expansion)	7360 Columbia Street, Port Hardy V0N 2P0	Vancouver Island	31-Mar-2022	Incomplete	Yes	No	4,315	n/a	0	1	50	2	1	
Port McNeill	Port McNeill (Expansion)	1594 Beach Drive, Port McNeill	Vancouver Island	31-Mar-2022	Incomplete	Yes	No	2,395	n/a	0	1	50	2	1	
Powell River	Powell River (Expansion)	5001 Joyce Avenue, Powell River	Non-Metro / Fraser Valley	31-Mar-2022	Incomplete	Yes	Yes	13,829	2	0	1	50	2	1	
Quesnel	Quesnel (Expansion)	2335 Maple Dr, Quesnel V2J6J6	Northern Interior	31-Mar-2022	Incomplete	Yes	Yes	10,392	1	0	1	50	2	1	
Delta	South Delta/Tsawwassen (Expansion)	1406 Tsawwassen Dr S, Tsawwassen V4M 4G2,	Metro Vancouver	31-Mar-2022	Incomplete	Yes	Yes	109,490	12	0	1	50	2	1	
Mission	Mission Superstore (Expansion)	32136 Lougheed Highway, Mission, BC	Non-Metro / Fraser Valley	31-Mar-2022	Incomplete	Yes	Yes	43,202	5	0	1	50	2	1	
Williams Lake	Williams Lake (Expansion)	450 Mart Street, Williams Lake	Northern Interior	31-Mar-2022	Incomplete	Yes	Yes	11,359	1	0	1	50	2	1	
Prince George	Prince George (Expansion)	2155 Ferry Avenue, Prince George V2N 5E8	Northern BC	31-Mar-2022	Incomplete	Yes	No	81,345	0	0	1	50	2	1	
Surrey	Surrey Tynehead Gas Station (Expansion)	16815 - 96th Ave, Surrey, BC	Metro Vancouver	31-Mar-2022	Incomplete	Yes	Yes	584,526	65	0	1	50	2	1	
Ucluelet	Ucluelet - Pacific Rim Visitor's Centre (Expansion)	2791 Pacific Rim Hwy, Ucluelet, BC	Vancouver Island	31-Mar-2022	Incomplete	Yes	No	1,842	n/a	0	1	50	2	1	
Surrey	Surrey - Powertech Labs (new site)	12388 88 Ave. Surrey, BC	Metro Vancouver	31-Mar-2022	Incomplete	Yes	Yes	584,526	65	0	2	50	4	2	
Note															
* Expansion refers to the addition of a station at an existing site.															

Eligible Charging Stations for Cost Recovery (Fiscal 2020 and Fiscal 2021)

GGRR Section		5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(b)(ii)	5(2)(b)(ii)	5(2)(c)
		Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that			For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
						Station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality?	Does the site exceed site limit?	
	Number of Stations at the Site								
Station Sites									
Surrey - Powertech Labs (to be decommissioned)	0	No	No	Yes	Yes	Yes	Yes	No	n/a
Nanaimo - Conference Centre	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Duncan - Island Savings Centre	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Kamloops - Hillside Stadium	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
North Vancouver - 1st & Lonsdale	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Sechelt - Trail Bay Mall	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Abbotsford - EcoDairy	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Revelstoke	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Langley Events Centre	1	No	No	Yes	Yes	Yes	Yes	No	n/a
Merritt Visitor Information Centre	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Hope	2	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Keremeos	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Salmon Arm	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Colwood - Park and Ride	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Boston Bar - Canyon Lanes	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Whistler	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Spences Bridge	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
West Kelowna	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Chase	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Princeton	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Chilliwack	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Manning Park	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Vernon	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Surrey Central City Hall (Decommissioned)	0	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Malakwa Supermarket	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Squamish	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Cranbrook	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Canal Flats - Columbia Discovery Centre	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Radium Community Centre	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Jaffray Pump & Pantry	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Ucluelet - Pacific Rim Visitor's Centre	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Port Alberni - No Frills	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Nanaimo - Superstore	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Richmond - Superstore	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Surrey - South Superstore	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Vancouver - Grandview Hwy Superstore	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Qualicum - Quality Foods	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Coquitlam - Superstore West	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
UBC - Wesbrook Place	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Campbell River - Community Centre	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Courtenay - Superstore	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Coquitlam - Superstore East	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Sidney	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Vancouver - Homer St	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
West Vancouver - Horseshoe Bay	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Mission Superstore	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Sparwood	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Britton Creek Rest Area	2	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Golden	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Surrey Tynehead Gas Station	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Vancouver - Kerrisdale	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Rogers Pass Discovery Centre	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Vancouver - SE Marine Drive Superstore	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Field - Yoho National Park	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Surrey - Cloverdale	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
70 Mile House	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a

Eligible Charging Stations for Cost Recovery (Fiscal 2020 and Fiscal 2021)

GGRR Section		5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(b)(ii)	5(2)(b)(ii)	5(2)(c)
		Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that			For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
						Station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality?	Does the site exceed site limit?	
Station Sites	Number of Stations at the Site								
Cache Creek	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Clinton	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Saanich	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Port Hardy	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Blue River	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Valemount	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
McBride	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Madeira Park	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
South Delta/Tsawwassen	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Powell River	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Quesnel	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Hixon	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Williams Lake	1	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Port McNeill	1	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Surrey Central City Hall (Decommissioned)	0	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Penticton (Decommissioned)	0	Yes	No	Yes	No	Yes	Yes	No	n/a
Prince George	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Burns Lake	2	Yes	No	Yes	Yes	Yes	No	n/a	n/a
Victoria	2	Yes	No	Yes	Yes	Yes	Yes	No	n/a
Total Stations	98								

NOTE: Unless otherwise indicated, each of the criteria of section 5 of the GGRR applies to each charging station at the respective site.
The total station number does not include the four decommissioned stations (showing as "0" in Column B).

New Eligible Charging Stations for Cost Recovery (Fiscal 2022)

GGRR Section		5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(a)(ii)	5(2)(b)(ii)	5(2)(c)
		Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that			For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
						Station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality?	Does the site exceed site limit?	
Station Sites	Number of Stations at the Site								
Seabird Island	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Fraser Lake	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Gold River	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Houston	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Kitimat	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Lillooet	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Maple Ridge	2	Yes	No	Yes	Yes	Yes	Yes	No	Yes
McLeod Lake	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
New Hazelton	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Burnaby	2	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Pemberton	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Prince Rupert	2	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Smithers	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Kitsumkalum FN-Terrace	2	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Vanderhoof	2	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Surrey - Powertech Labs	2	Yes	No	Yes	Yes	Yes	Yes	No	Yes
70 Mile House (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Blue River (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Cache Creek (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Cranbrook (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Duncan (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Kamloops - Hillside Stadium (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Madeira Park (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Manning Park (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
McBride (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
McLeod Lake (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Merritt Visitor Information Centre (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Mission Superstore (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Nanaimo - Conference Centre (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Port Hardy (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Port McNeill (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Powell River (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Prince George (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Quesnel (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Salmon Arm (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
South Delta/Tsawwassen (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Spences Bridge (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Surrey Tynehead Gas Station (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Ucluelet - Pacific Rim Visitor's Centre (Expansion)	1	Yes	No	Yes	Yes	Yes	No	n/a	Yes
Vernon (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
West Kelowna (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Williams Lake (Expansion)	1	Yes	No	Yes	Yes	Yes	Yes	No	Yes
Total Stations	57								

NOTE: Unless otherwise indicated, each of the criteria of section 5 of the GGRR applies to each charging station at the respective site.

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix D

Load Forecast Methodology

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1 Introduction

This report is supplemental to the Load Forecast information presented in Chapter 3 of the Application. Its purpose is to provide further information on:

1. The methodology used to develop the March 2020 Load Forecast; and
2. The two scenarios developed after the onset of the COVID-19 pandemic.

Load forecasting is central to BC Hydro's long-term planning, medium-term investments, and short-term operational and forecasting activities. BC Hydro's Electric Load Forecast is used to provide decision-making information for electricity rates, as well as where, when, and how much electricity we expect to need from the BC Hydro system. About two-thirds of the forecast is based on Statistically Adjusted End Use (**SAE**) econometric (regression) models that use historical billed sales data combined with economic forecasts and inputs from internal, government and third-party sources. The other approximately one-third of the forecast is derived from individual forecasts of our large industrial customers.

2 Types of Load Forecasts

Given the variety of uses, our load forecast consists of a suite of forecasts, each of which fulfills different user requirements. For example, integrated system energy planning considers system losses associated with delivering energy from generation resources to our customers, but not the forecast demand from customers that are not connected to our integrated system (i.e., this is referred to as our total integrated gross system requirements). Revenue forecasting includes all customer demand (i.e., domestic sales, including non-integrated customers, sales to other utilities, and firm exports), but does not consider losses or BC Hydro's own use. In addition, the British Columbia Utilities Commission (**BCUC**) requires us to separately reflect the impacts associated with future electricity price increases (rate impacts) and

Demand-Side Management (**DSM**) plan savings. Rate impacts are load reductions estimated using price elasticity and bill impact projections in real dollars (net of inflation).

2.1 Forecasts to Characterize Uncertainty

In addition to the reference forecast, we develop high and low uncertainty bands which represent ranges around the reference forecasts. These high and low uncertainty bands are produced because there is uncertainty in the input variables that predict future loads and in the predictive capabilities of the forecasting models themselves.

2.2 BCUC Required Forecasts

Following the BCUC's requirements, we produce three types load forecasts:

- Before considering rate impacts, DSM and loss reductions;¹
- After considering rate impacts, but before DSM and loss reductions; and
- After considering rate impacts, DSM and loss reductions.

The Load Forecast information presented in Chapter 3 of the Application is our forecast of sales including rate impacts, incremental DSM savings and savings from our loss reductions program. The loss reduction program accounts for efficiencies at BC Hydro's distribution substations to minimize line losses and is separate from our DSM plan.

BC Hydro develops an electricity sales forecast for each of its main customer sectors including residential, commercial, light industrial, and large industrial. We also develop a forecast of electricity sales to other utilities and firm exports supplied

¹ Loss reductions were referred in our Fiscal 2017 to Fiscal 2019 Revenue Requirements Application as volt-ampere reactive (**VAR**) and voltage optimization (**VVO**) savings.

by BC Hydro. The methodology used for each sector as well those for other utilities and firm exports are the focus of this report.

3 Residential Sector Methodology

The residential sector consists of approximately 1.9 million accounts and represents about one-third of BC Hydro's total sales.

3.1 Residential Sector Description

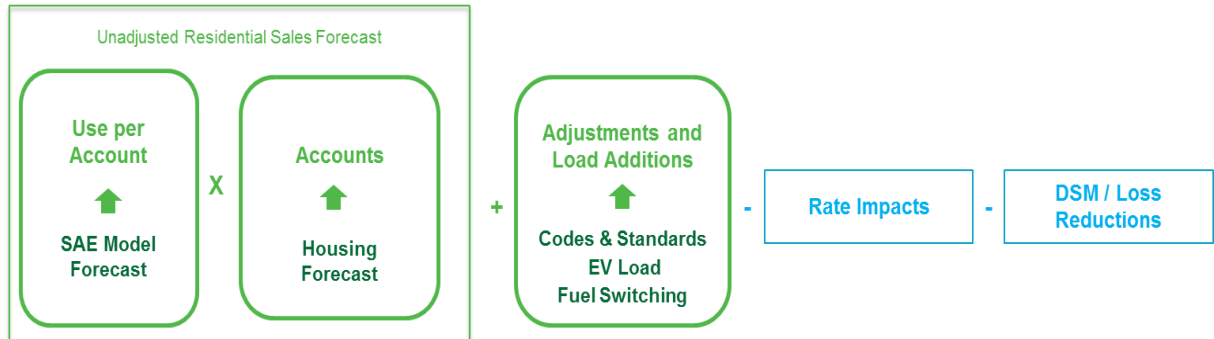
Residential customers use electricity for a variety of what are referred to as end-uses. These include space heating, cooling, lighting, water heating, cooking, refrigeration, and other plug-in loads which include computer equipment and home entertainment systems. Since space heating and cooling loads are dependent on the outside temperature, residential sales are affected by temperature. As such, our forecasting process, like most utilities, develops a residential sales forecast based on average temperature variables (i.e., heating and cooling degree days) over the forecast period. This is referred to as a "temperature normalized basis" and is derived from a rolling average of temperatures over the past 10 years.

BC Hydro has four main service regions: Lower Mainland, Vancouver Island, South Interior, and the North Region. The North Region includes customers connected to our integrated grid and those in our non-integrated areas.

3.2 Forecast Build-Up

[Figure D-1](#) below shows our forecasting process and the build-up of the Residential Load Forecast.

Figure D-1 Residential Load Forecast Build-up



The equation used to develop the unadjusted residential sales forecast, represented in the first part of the figure, is:

$$\begin{aligned} & \text{Unadjusted Residential Sales Forecast} \\ &= \text{Number of Residential Accounts} \times \text{Intensity (average use per account)} \end{aligned}$$

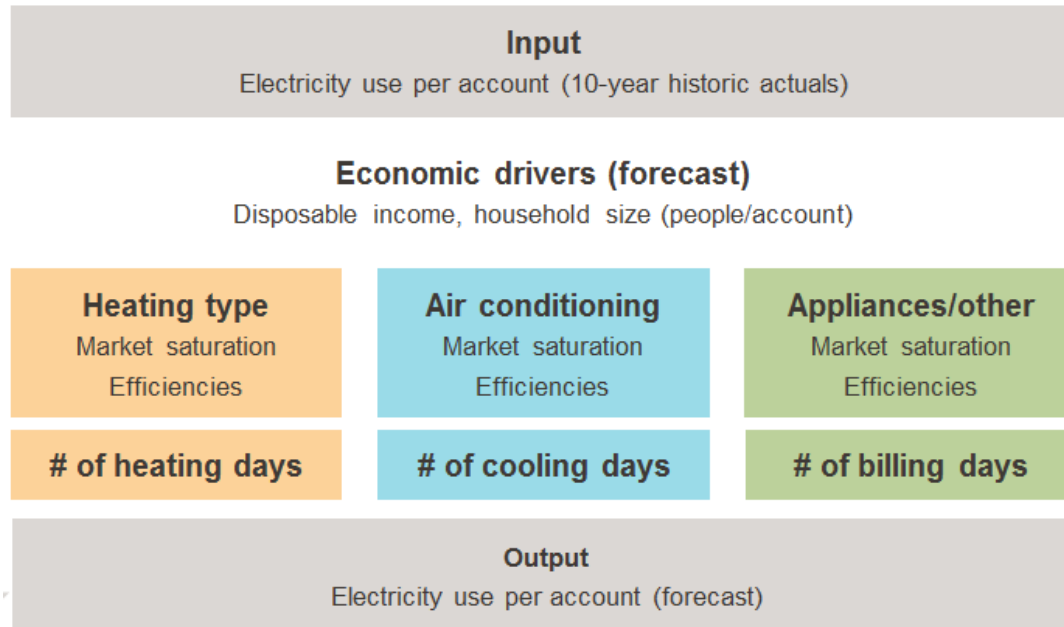
This equation is applied to develop residential model projections of sales for each of our four service regions.

The total residential model projection of sales for our service area is the sum of the four regional model projections.

3.3 Residential SAE Models

The model projection of average use per account comes from four SAE models (i.e., one model per each major region). [Figure D-2](#) below is a graphical representation of the SAE model.

Figure D-2 Residential SAE Model Inputs and Outputs



SAE models are called statistical regression models because they involve a set of statistical processes for estimating the relationships between electricity consumption and variables that influence electricity consumption.

In the case of residential forecasts, the SAE models identify the relationships between electricity use per account and the following variables over the most recent 10-year history (model calibration period):

- Consumer preferences and average efficiency of electricity end uses;
- Temperature variables;
- People per household; and
- Disposable incomes.

Using the relationships established from the model calibration period the models then generate forecasts of future electricity use per account based on expectations

of future electricity end-use average efficiency trends, people per household, disposable incomes, and average temperature conditions. Future electricity end-uses incorporate projected improvements in average energy consumption efficiency in items such as space heating, cooling, lighting, water heating, cooking, refrigeration, and other plug-in loads which include computer equipment and home entertainment systems. These projections are developed with a combination of BC Hydro's own recent residential end use survey data and recent data from the U.S. Energy Information Administration (EIA).²

3.4 Residential Accounts

The number of accounts is derived by multiplying the previous year's forecasted number of accounts by the account growth projection. The account growth projection is based on the historical ratio of accounts growth compared to housing growth. Housing growth forecasts are developed for 15 sub-areas (aggregated to four service regions then aggregated to a BC Hydro total) with the projections of housing growth by housing type within these areas provided by the Conference Board of Canada's (CBoC) economic forecast. The CBoC also provides the disposable income growth forecast as well as the provincial population forecast, which we use to calculate people per household; which is an input into the SAE model.

4 Commercial Sector Methodology

The commercial sector has over 180,000 accounts and represents approximately 28 per cent of BC Hydro's total firm sales.

² The Energy Information Administration is an agency of the U.S. Federal Statistical System.

4.1 Commercial Sector Description

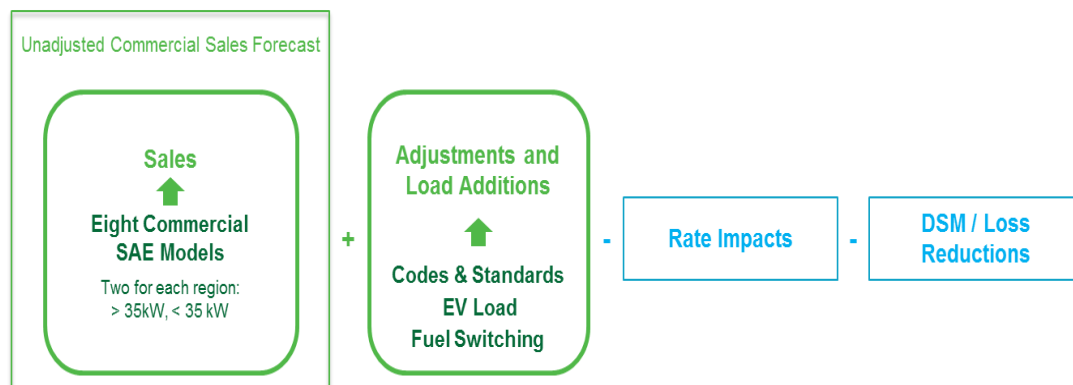
The commercial sector is diverse and includes everything from small corner stores to large warehouses, schools, office buildings, restaurants, and health care facilities.

Given the diversity of businesses and type of operations within the commercial sector, commercial electricity sales are not as sensitive to temperatures as the residential sector. However, some commercial customers such as schools, restaurants, and smaller health care facilities are more sensitive to temperature. Even though the total commercial load is not as temperature sensitive compared to the residential load, we still appropriately factor into our commercial forecasting models the historical average temperature variables (i.e., heating and cooling degree days) over the forecast period. As such, the commercial forecasts are prepared on a temperature normalized basis and the actual commercial sales are temperature normalized.

4.2 Commercial Forecast Build-Up

[Figure D-3](#) below shows the commercial forecasting process and build-up of the Commercial Load Forecast after DSM and loss reduction savings.

Figure D-3 Commercial Load Forecast Build-up



Looking to the left-hand portion of [Figure D-3](#), the starting point in the commercial forecasting process is the commercial SAE model projections.

4.3 Commercial SAE Models

While the residential sector uses the SAE model to forecast use per account, the commercial sector SAE models estimate commercial sales directly. The commercial SAE models use statistical regressions to establish relationships between commercial sales, major commercial electricity end-uses, temperature variables, and economic variables over the most recent 10-year period (i.e., the model calibration period). The models then forecast future sales based on forecasts of economic variables (such as commercial Gross Domestic Product (**GDP**), employment, and retail sales) provided by the CBoC, the recent U.S. EIA forecasts for future end-use average efficiency trends, share of commercial electricity equipment, and temperature conditions based on a rolling 10-year historical average (as is considered in the residential SAE model).

We use multiple SAE models to develop the commercial sector load forecast: for each of the four major service regions; and within each region a separate SAE model is used for small commercial customers (below 35 kW peak demand within a month) and large commercial customers (above 35 kW peak demand within a month).

5 Residential and Commercial Forecast Adjustments

For both residential and commercial sectors, a number of adjustments are made outside the SAE model result to account for items that are not captured in the models. These include the following:

- **Codes and standards overlap:** Once the SAE models produce results, an adjustment is made to account for the fact that there is an overlap between energy conservation savings included in our SAE models' results and savings

derived from our DSM plan that are included later in the process. This overlap results because there are energy savings from codes and standards that are reflected in both our DSM plan and the U.S. EIA assumptions included in the SAE model. An example of such a standard is an appliance minimum efficiency standard. Adjustments are made to the SAE models' results to mitigate potential double counting by using an estimate of the overlap between the SAE models and our DSM plan;

- **Add loads not accounted for in the SAE model:** which include:
 - ▶ Electric vehicle load allocated to the residential and commercial sectors:
Electric vehicle load is estimated from BC Hydro's electric vehicle forecast model. The residential sector is allocated 85 per cent of the electric vehicle model's results and the commercial sector is allocated 15 per cent. The allocation is based on recent data on electric vehicles from the Insurance Corporation of British Columbia (**ICBC**); and
 - ▶ Fuel switching load: New loads when customers convert from a non-electric source of energy to electricity. Fuel switching is forecast based on specific government or BC Hydro programs that incentivize customers to switch from fossil fuel-based energy to clean electricity (i.e., low carbon electrification); and
- **Subtract loads for various reasons:** Adjustments to load to account for three other sources of load reductions:
 - ▶ Rate impacts: Load reductions estimated using price elasticity and bill impact projections in real dollars (net of inflation). Price elasticity is the impact of future electricity rate increases on customer demand. Price elasticity is expressed as the per cent change in quantity to a 1 per cent change in electricity price. As was done in the October 2018 Load Forecast, the March 2020 Load Forecast used a price elasticity of -0.10 for all sectors;

-
- ▶ Loss reductions: Load reductions to account for efficiencies at BC Hydro's distribution substations to improve voltage levels to minimize line losses resulting in energy savings; and
 - ▶ DSM savings: Load reductions to account for our DSM plan.

6 Light Industrial Forecast Methodology

6.1 Light Industrial Sector Description

The light industrial sector consists of approximately 29,000 customers connected at the distribution level and represents a relatively small component of the overall load forecast. As such, a variety of forecasting methods are used, ranging from account by account forecasts, regression models, and production intensity-based methods.

6.2 Light Industrial Sub-Sector Methodologies

These industrial sub-sectors and descriptions of their forecast methods are listed below:

- **Coal Mining:** The forecast is determined on an individual customer account basis in a similar manner to large industrial coal mining customers, which is described in the section [7](#) below;
- **Forestry:** Customers in this sub-sector are sawmills, panel mills, and pellet plants. The forecast for this sub-sector is determined by developing mill by mill production forecasts, aggregating those forecasts by region, and then multiplying the total by the historical electricity use intensity for each region and mill type;
- **Oil and Gas:** Customers in this sub-sector are primarily in production and processing, transport (pipelines, pump stations, truck terminals) and support services for the oil and gas industry. The forecast is primarily determined on an

individual customer account basis in a similar manner to large industrial oil and gas customers, which is described in section [7](#) below; and

- **Other Light Industrial:** Sales for this sub-sector are primarily forecast using a regression model built on the historical relationship between sales to these customers and provincial GDP. The inputs to the regression model used to determine the sales forecast is the short-term GDP forecast from the B.C. Ministry of Finance and long-term GDP forecast provided by the CBoC. The following additional loads are added to the other light industrial sub-sector;
 - ▶ **Cannabis and Cryptocurrency:** as emerging industries, the forecast is developed with consideration of customer requested loads that are deemed highly probable based on their advanced stage of progress in BC Hydro's interconnection process; and
 - ▶ **Construction of LNG (liquefied natural gas) Plants:** The required load expected to power the construction of LNG plants and other facilities is considered. These construction loads are considered separately from plant operational requirements.

As with the residential and commercial sector forecast methods, two further steps are undertaken for the light industrial sector forecast: fuel switching load estimates are added to the sector as a whole and estimated load is adjusted to account for rate impacts and DSM savings.

7 Large Industrial Forecast Methodology

7.1 Large Industrial Sector Description

BC Hydro has approximately 190 large industrial accounts representing approximately 26 per cent of BC Hydro's total sales. Customers in the large industrial sector are generally categorized into the same sub-sectors as light industrial customers (mining, forestry, oil and gas, and other large industrial

customers). Examples of large industrial accounts are pulp mills, refineries, and manufacturing plants. Sales of electricity to the large industrial sector are forecast on an individual customer account basis.

7.2 Large Industrial Forecast Methodology

The account-by-account analysis methodology applied in the large industrial sector load analysis provides greater flexibility to quantify relevant factors for each of the main sub-sectors and individual customer energy sales. It also provides greater detail for tracking and explaining forecast variances. This flexibility and detail allow BC Hydro to monitor and consider the potential impacts of large-scale economic changes on particular customers, and the impacts of industry changes on BC Hydro, for example in the case of a delayed project or the shutdown of a specific facility.

BC Hydro develops the Large Industrial Sector Load Forecast using information from several sources. These sources include:

- **Industry experts:** BC Hydro retains external consultants to develop production and commodity price forecasts and provide facility and/or sector specific market assessments;
- **Market research:** BC Hydro subscribes to a number of publications from companies that provide market research and industry analyses. BC Hydro also relies on various publicly available reports from government agencies, such as the British Columbia Oil and Gas Commission; and
- **Information from our customers:** BC Hydro uses customer specific information gathered by our Key Account Management and Load Interconnections groups, which are in direct contact with our customers.

Using these sources of information, we develop a probability weighting for expected sales to our current and potential new customers. This probability weighting

1 represents a risk assessment of the likelihood of future sales increasing, decreasing
2 or remaining steady.

3 Like the October 2018 Load Forecast, the March 2020 Load Forecast used a binary
4 approach for the first three years of the forecast rather than probability weighted.

5 This means that the probability weighting, which we develop for each customer, is
6 used to inform an “in” or “out” call for each customer in the first three years of the
7 forecast. Customers with a greater than or equal to 50 per cent weighting are
8 included in the forecast at their full anticipated load. Customers falling below that
9 probability are excluded from the forecast for all years of the forecast. For example,
10 a customer with a low probability weighting - say a 25 per cent probability - would
11 not be included. The binary method results in discrete projection (i.e., in or out) of
12 load and revenues. Given that we have good information to make the binary call, we
13 believe forecasting load in this manner is preferred over the short term rather than
14 having partial load and partial revenue projections.

15 Finally, BC Hydro makes load additions and reductions similar to those made for the
16 residential and commercial and light industrial sectors. Specifically, load from fuel
17 switching is added. Load reductions are then applied for rate impacts, loss
18 reductions and DSM savings.

19 **8 Other Sector Forecast Methodology**

20 **8.1 Other Sector Description**

21 The Other sector currently represents approximately 3 per cent of the total sales
22 demand in the Load Forecast. Demand in this sector comes from irrigation and
23 street light customers, inter-utility sales (City of New Westminster and FortisBC Inc.),
24 and firm exports (Seattle City Light and Hyder, Alaska) specifically.

8.2 Other Sub-Sector Methodologies

The sub-sectors of the Other sector are forecast as follows:

- **Irrigation and Street Lighting:** The forecast is based on historical growth trends;
- **FortisBC Inc.:** The forecast is based on information provided by FortisBC Inc. as well as projections from our internal model that considers the forecast of electricity market prices relative to the cost of purchases from BC Hydro under Rate Schedule 3808;
- **The City of New Westminster:** The forecast is based on historical load as well as information provided by the City of New Westminster regarding new residential and commercial loads;
- **Seattle City Light:** This forecast is determined by the Skagit River Valley Treaty which prescribes sales of approximately 310 GWh per year; and
- **Hyder, Alaska:** The forecast is based on historical load.

Load reductions are then applied for rate impacts. However, this step does not apply to Seattle City Light's or FortisBC Inc.'s loads. Sales to Seattle City Light loads are established under the Skagit River Valley Treaty. As such, there is no rate to which Seattle City Light revenues and sales are calculated. Sales to FortisBC Inc. have the elasticity impact implicitly built into the methodology. The methodology considers the cost of purchases from BC Hydro which are subject to rate increases versus the cost of purchases from the market.

9 Electric Vehicle Forecast

BC Hydro develops an electric vehicle (EV) load forecast to estimate electricity sales across our system due to growth in the total number of EVs. The EV forecast is split amongst the residential sector and commercial sectors based on ICBC data on the

number of light duty electric vehicles that are for personal and business use. As a result, 85 per cent of the total electric vehicle load forecast is allotted to the residential sector and 15 per cent is allotted to the commercial sector.

9.1 Electric Vehicle Forecast Methodology

BC Hydro's EV load forecast is based on BC Hydro's in-house EV stock turnover model (**EV model**). The EV model combines both types of EVs (battery plug-in vehicles and plug-in hybrid vehicles).

The EV model starts with a forecast of the annual EV market share (ratio of the annual number of EVs to the annual number of vehicles). The key drivers for determining the market share include:

- (i) A distribution of the driving distance for all types of vehicles; and
- (ii) The costs of electric vehicles relative to internal combustion engine (**ICE**) vehicles which are broken down to fixed and variable costs.

The fixed cost reflects the capital related costs of vehicles, which include median sales prices (for both EVs and ICE), announced government incentives, and home charging costs for EVs. Variable costs reflect operating costs which are determined by the annual distance driven, fuel efficiencies, and electricity rates versus ICE fuel prices.

The EV model randomly selects an annual distance driven from an overall probability distribution of annual distance driven per vehicle (fitted to historical data). Next, the model computes the total cost as for the randomly selected annual distance driven and compares it to a break even cost and the range constraint, which is the maximum annual distance driven or maximum range (in kilometres) for EVs. The break-even cost is the cost at which the model estimates an indifference to gasoline vehicles and EVs. The comparison analysis results in the initial annual EV market share.

1 The initial market share is adjusted over the near term of the forecast period to
2 reflect an assumed gradual development of adoption of EVs.

3 The forecast of the annual total number of EVs is determined by the product of the
4 EV market share and the total vehicle purchase forecast.

5 The total vehicle purchase forecast is determined by the product of the driving
6 population forecast and an estimate of the number of vehicles per driver.

7 The stock turnover portion of the EV model keeps track of the vehicle life expectancy
8 and the annual distance driven of electric vehicles.

9 The annual electric vehicle load in GWh resulting from a product of these three
10 variables: the total number of electric vehicles, the annual distance driven per EV,
11 and the average efficiency of electric vehicles.

12 **10 Non-Integrated Areas, Purchase Areas, and Fort** 13 **Nelson**

14 There are a number of small communities in parts of B.C. not connected to
15 BC Hydro's integrated transmission grid which are forecast separately. Descriptions
16 of the communities and their forecast methodologies follow.

17 The methodologies used for these areas range from trend analysis, development of
18 specific customer load forecasts, and regression models. The forecasts developed
19 from these methods are supplemented with information from local community
20 members about future loads.

21 Rate impacts are developed in the same manner as they are developed for the main
22 customer sectors described in this report. Savings from our DSM plan identified for
23 these areas are allocated to each area based on an historical sales percentage
24 basis. An allocation of the DSM savings is used because it is not exactly known
25 which particular areas will engage in DSM activities.

10.1 Non-Integrated Areas

The Non-Integrated Areas (**NIA**) contain customers in the Zone 1B community of Bella Bella in the North Region and Zone II communities in the North Region and Vancouver Island. Zone II NIA customers include communities from the following locations³: Anahim Lake, Atlin, Bella Coola, Dease Lake, Elhateese, Fort Ware (Kwadacha), Good Hope Lake, Haida Gwaii (includes Masset and Sandspit), Hartley Bay, Jade City, Telegraph Creek, District of Toad River, and Tsay Keh Dene.

For Zone II and Zone 1B communities, the forecasts are developed using a trend analysis of the historical loads that make up major sectors in these areas. A trend analysis is carried out for the residential sector, commercial and light industrial sector and other loads such as street light customers, irrigation customers and BC Hydro own use. The trend analysis establishes a base load forecast which is supplemented by other forecast information on individual projects or customers loads. This additional load information is obtained from customer service requests via local BC Hydro personnel or identified by BC Hydro's distribution regional planners. These load additions tend to be the main drivers of load growth within these communities.

10.2 Purchase Areas

The Purchase Areas consists of the following six locations in the South Interior: Lardeau, Crowsnest, Newgate, Kingsgate-Yahk, and Kelly Lake. To serve customers in the Purchase Areas, BC Hydro purchases electricity from neighbouring electric utilities.

For the Purchase Areas, the energy forecast is developed by a trend analysis of the historical total gross requirements of the communities that makes up the Purchase Areas.

³ In [Table D-1](#), loads for the community of Eddontenajon are not included because this community is connected to our integrated transmission grid.

10.3 Fort Nelson

A separate forecast is developed for customers in the Northern Rockies Regional Municipality (Fort Nelson area) in the North Region.

For Fort Nelson area sales, the forecast is developed as the sum of the forecast for each of the major customer sectors including residential, commercial and light industrial and a large industrial sector as follows.

- The forecast for the residential sector is the product of the accounts and the average use per account. The accounts projection uses the same methodology as described in section [3.4](#) above. The average use per account projection is based on a trend analysis of historical billing data. A trend analysis is used because there is not enough resolution (i.e., detail in our residential end use survey) to develop a statistically sound SAE model for the residential and commercial load;
- The forecast for the commercial and light industrial sector is developed with a regression model involving historical sales and employment where the history and forecast of employment comes from CBoC Economic Forecast;
- The forecast for the wood product segment which consists of two mills, currently shutdown, is developed on an account-by-account basis;
- The forecasts for the two large industrial customers in the Fort Nelson area are also developed on an account-by-account basis using the same methodology that applies to other oil and gas loads connected to the integrated grid; and
- The forecasts for street lighting customers, irrigation customers and BC Hydro own use within the Fort Nelson area are developed based on a trend analysis.

11 Other Utilities

The load forecast also includes other utilities which have formal arrangements with BC Hydro for electrical service.

11.1 Other Utilities Sector Description

The other utilities served by BC Hydro are listed below:

- City of New Westminster, located within the Lower Mainland Region,
- FortisBC Inc., located in southeastern B.C.,
- Seattle City Light, located in the Washington State, and
- Hyder, Alaska.

Hyder is served at distribution voltage while the other three utilities are served at transmission voltage.

11.2 Other Utilities Forecast Methodology

The forecast methodology varies by utility, as follows:

- The forecast for the City of New Westminster is based on trend analysis and information from BC Hydro's distribution planners on new larger projects that have requested electricity service;
- The forecast of sales to FortisBC Inc. is based on a modelled comparison of the relative cost of purchasing electricity from BC Hydro (including future rate increases) applied to Rate Schedule 3808 versus the cost of market purchases. The model also considers information provided by FortisBC Inc. on its expected purchase of electricity from BC Hydro. Since the forecasting model determines the forecast of sales to FortisBC Inc. by the relative costs of purchases (i.e., market vs. BC Hydro rates) it already accounts for the impact future

changes in our electricity rates. As such, there is no need to apply a further rate impact to the results of the model;

- The forecast for Seattle City Light is prescribed within a treaty between British Columbia and Seattle dated March 30, 1984 and which expires on January 1, 2066; and
- The sales forecast for Hyder, Alaska is based on a trend analysis.

12 Developing Load Forecast Uncertainty Bands

Load forecasts are sensitive to many input variables, each of which has varying degrees of uncertainty associated with it. These uncertainties influence the risk that future loads will be lower or higher than forecast. They can exist at a customer-specific level up through to sector-wide or economy-wide levels. To account for this, BC Hydro develops uncertainty bands to account for a low-to-high range of outcomes.

For BC Hydro's most recent March 2020 Load Forecast, two different methods were used to develop the low and high uncertainty bands around the mid (reference) forecast: A Monte Carlo simulation method and a discrete forecast method. This improvement was based on observations that showed the uncertainty bands did not fully capture load variability within the large industrial sector. The new approach creates an asymmetrical uncertainty band around the energy and peak reference forecasts and also widens the bands.

For the distribution portion of the forecast (i.e., the aggregate sum of residential, commercial and light industrial sector forecasts), a Monte Carlo simulation technique is applied using BC Hydro's in-house Monte Carlo uncertainty model and a simulation process.

1 The Monte Carlo model projects high and low load ranges by analyzing and
2 modeling the relationships between energy sales and the predictors of future sales,
3 referred to as load drivers. Load drivers are both economic and non-economic
4 variables, such as such as temperature (i.e., heating degree days) and economic
5 activity (i.e., GDP).

6 The Monte Carlo simulation process uses a randomly-selected sample of probability
7 distributions to produce a range of load outcomes in the form of a probability
8 distribution for each customer sector, total firm sales, and the total system and total
9 integrated system gross requirements. The uncertainty in forecasting is mitigated by
10 using a large number of random simulations (5,000 times for each year of the
11 20-year forecast), which results in a symmetric distribution.

12 To assess the range of forecast uncertainty, we use p-90 and p-10 forecast
13 outcomes to represent the high and low uncertainty bands, respectively, around our
14 mid (reference) forecast. The p-90 forecast outcome indicates that there is a
15 90 per cent chance that forecast outcomes will be below the value shown as p-90.
16 Similarly, the p-10 forecast outcome indicates there is a 10 per cent chance that
17 forecast outcomes will be below the values shown as the p-10. These two forecast
18 outcomes provide the probability of distribution of all possible forecast outcomes.
19 Given the p-90 and p-10 forecast outcomes, the range of uncertainty represents an
20 80 per cent confidence interval.

21 The EV forecast and incremental DSM are applied after the uncertainty bands are
22 produced by the Monte Carlo analysis.

23 For our EV sector forecast uncertainty band we develop discrete low and high
24 forecasts. The low and high forecast are developed by varying key input
25 assumptions that result in lower and higher EV sales relative to the mid (reference)
26 forecast.

1 For our large industrial sector forecast uncertainty band we develop discrete low and
2 high forecasts for each of the major sub-sectors making up the industrial sector. The
3 low and high forecasts are developed based on various commodity price
4 assumptions and market conditions that are lower/weaker and higher/stronger,
5 respectively, relative to assumptions underpinning the mid (reference) forecasts. In
6 turn these assumptions inform probability weighting assessments for existing and
7 potentially new customers similar to the process used to develop the mid (reference)
8 large industrial forecast.

9 The low and high uncertainty band for the large industrial sector is the aggregate of
10 low and high forecasts for each of the major subsectors.

11 The load forecast uncertainty band for all customers in the March 2020 Load
12 Forecast was the aggregated output of the Monte Carlo simulation (p-10 result
13 representing low band; p-90 result representing high band) for distribution customers
14 (residential, commercial, light industrial), discrete low and high bands for electric
15 vehicles and discrete low and high bands for the large industrial sector.

16 **13 The Forecasting Models are Reliable**

17 The forecast models used by BC Hydro are consistent with industry best practices
18 and are frequently reviewed to assess potential risks and improvements. SAE
19 models, for example, are considered the industry best practice for energy load
20 forecasting. BC Hydro's use of the SAE model is periodically reviewed by an
21 external modelling consultant for continuous improvements.

22 In 2017, the Corporate Affairs Business Group conducted an audit of BC Hydro's
23 forecasting models. GDS Associates Inc. (**GDS**) was retained as a subject-matter
24 expert for the audit. GDS is a U.S. based firm with extensive experience with load
25 forecasting in the electrical utility industry. The Load Forecasting Audit was
26 conducted in conformity with the International Standards for the Professional

Practice of Internal Auditing. Overall, the Load Forecasting Audit found that BC Hydro's load forecasting methodologies are consistent with best practices and load forecast outputs are provided to users and stakeholders on a timely basis.

The Load Forecasting Audit considered the SAE model specifically and reviewed prior residential and commercial load forecasts to analyze reliability. The Load Forecasting Audit found that forecast variances for the residential and commercial classifications were within a range of expectancy based on industry benchmarks developed by Itron Inc. and the U.S. EIA.

14 COVID-19 Scenario Methodology

The COVID-19 global pandemic that was declared in early 2020 created a significant degree of unexpected uncertainty for BC Hydro. As discussed in Chapter 3, section 3.2.4, BC Hydro responded by developing two scenarios to inform decision making. The key assumptions underpinning the two scenarios are described in that section, and the methodology used to develop the scenarios is described below.

14.1 Residential Sector

For the residential sector we relied on SMI data comparing current loads to previous load periods, on a temperature normalized basis, recognizing that there is significant potential error in trying to temperature normalize load during the Spring shoulder season.

In the case of the residential sector, load projections were based on the difference between current load and the previous year's load over the same period (so April 2020 versus April 2019). The residential load is estimated to increase in both scenarios as more people stay home, so use per account increases.

Detailed assumptions are outlined below.

Scenario A

- Measures Phase (April to May 2020): Used SMI actuals to increase the residential load at an aggregate level on a temperature normalized basis;
- Recovery Phase (June to December 2020): Assumed load linearly returns to the March 2020 Load Forecast; and
- Long Term Projection Phase (January 2021 to March 2023): Assumed that starting January 2021 the forecast returns to that expected in the March 2020 Load Forecast.

Scenario B

- Measures Phase (April to August 2020): Used SMI actuals to increase the residential use per account on a temperature normalized basis. Assumed 75 per cent decline in account growth during this phase;
- Targeted Measures Phase (September 2020 to August 2021): Increased use per account by 75 per cent of the amount added in the measures phase. Assumed 50 per cent decline in account growth during this phase;
- Recovery Phase (September 2021 to March 2022): Assumed use per account linearly recovers to what was projected in the March 2020 Load Forecast. Assumed 25 per cent decline in account growth during this phase; and
- Long Term Projection Phase (April 2022 to March 2023): Assumed the use per account returns to what was projected in the March 2020 Load Forecast. Assumed account growth would return to 90 per cent of the March 2020 Load Forecast.

14.2 Commercial Sector

In the case of the commercial sector, our load projections were based on the difference between temperature normalized load in the first week of April and the

load in the first week of March (prior to the COVID-19 public health measures being put in place).

Scenario A

- Measures Phase (April to May 2020): Used temperature normalized SMI actuals to reduce the load in this phase to what was observed in the first week of April;
- Recovery Phase (June to December 2020): Assumed load linearly returns to the March 2020 Load Forecast; and
- Long Term Projection Phase (January 2021 to March 2023): Assumed that starting January 2021 the forecast is the same as the March 2020 Load Forecast.

Scenario B

- Measures Phase with Essential Services Only (April to August 2020): Used a mix of SMI actuals and professional judgment to estimate the impact on the individual sub-sectors (offices/restaurants/etc.);
- Targeted Measures Phase (September 2020 to August 2021): Assumed linear recovery to 88 per cent of the March 2020 Load Forecast. The 12 per cent difference was estimated by using SMI data and our professional judgment to estimate how much the individual sub-sectors would recover during the targeted measures phase;
- Recovery Phase (September 2021 to March 2022): Assumed load linearly returns to 95 per cent of the March 2020 Load Forecast; and
- Long Term Projection Phase (April 2022 to March 2023): Assumed the commercial load will settle at 95 per cent of what was projected in the March 2020 forecast.

14.3 Light industrial Sector

For the light industrial sector, we used our GDP regression model and the economic impact scenarios published by the BC Business Council (**BCBC**) on March 27, 2020. For Scenario A we applied the BCBC scenario one (7.3 per cent GDP decline) in 2020. After 2020, for Scenario A we assumed a return to previous forecast GDP growth (2.0 per cent). For Scenario B we applied the BCBC scenario two (11.4 per cent GDP decline) in 2020. After 2020, for Scenario B we assumed a slower GDP growth (1.0 per cent) in fiscal 2022. This means we assumed no economic rebound, but rather slower recoveries in both scenarios.

We adjusted the forecast for the forestry and oil and gas sub-sectors based on the results of the GDP regression and updated the outlook for several cannabis customers based on public announcements.

14.4 Large Industrial Sector

For each of the large industrial sub-sectors we applied an abbreviated version of our existing forecast method described in Section [7](#) above. We made assumptions about the extent to which commodity prices will continue to be depressed as a result of the COVID-19 pandemic impacts on the global economy and then, working with BC Hydro's Key Accounts group, undertaking a customer-by-customer assessment for each of the two scenarios.

We also communicated directly with our large industrial customers to determine possible impacts of COVID-19 pandemic on individual accounts. That allowed for an assessment of a range of possible outcomes, including:

- A temporary reduction in consumption in major industries such as forestry;
- Permanent closures of industrial facilities; and
- Potential delays in the construction of major infrastructure projects.

1 For the forestry and oil and gas subsectors, we also considered the exacerbating
2 effects of other market pressures (i.e., fibre supply shortages on forestry; global oil
3 price war on oil and gas).

4 BC Hydro relied significantly on professional judgment and experience of the staff in
5 the Load Forecast department. At the time the assessment was undertaken, there
6 was broad recognition of the unprecedented uncertainty that existed regarding the
7 magnitude and duration of economic impacts of the COVID-19 pandemic. Our
8 research showed there was a wide range of views with no consensus: economic
9 projections were continuously being revised (typically downwards) and there were
10 almost no economic impact projections that extended beyond one year.

11 **14.4.1 Forestry**

12 Forestry is assumed to be significantly impacted in both scenarios, as shown by
13 advancing the expected closure of one major pulp mill and a permanent line closure
14 in another in both scenarios. Both scenarios also assume temporary closures within
15 both the pulp and paper and wood products sub-sectors.

16 **14.4.2 Mining**

17 Mining is assumed to be moderately impacted by reduced production in Scenario A
18 and significantly impacted, but only by temporary shutdowns, in Scenario B. Both
19 scenarios assume return to production by fiscal 2023.

20 **14.4.3 Oil and gas**

21 In the oil and gas sub-sector, it is assumed there will be varying levels of project
22 deferrals and some production curtailments that have smaller impacts in the
23 two-year period under each scenario. In general, the assumption is there will be less
24 of an impact relative to the other large industrial sectors. This assumption is
25 notwithstanding the possibility of reduced Alberta oil sands production, which uses
26 natural gas and natural gas liquids, due to the health measures. Both scenarios

1 assume a return to production levels assumed in the March 2020 forecast by
2 fiscal 2023. LNG impacts over the fiscal 2021 to fiscal 2023 period are assumed to
3 be minor in both scenarios.

4 **14.5 Scenario results**

5 Scenario A and Scenario B were then applied to the March 2020 Load Forecast to
6 determine the potential decreases based on each scenario, both in terms of GWh
7 and the percentage decrease in load by sector. The analysis covered BC Hydro's
8 main customer classes (residential, commercial, light industrial and large industrial),
9 which make up the bulk of BC Hydro's load. For speed, the impacts on BC Hydro's
10 other customer sector (i.e., Irrigation and Street Lighting, FortisBC Inc., the City of
11 New Westminster, Seattle City Light, and Hyder, Alaska) were not assessed as
12 these make up a relatively small portion of BC Hydro's total load.

13 The COVID-19 pandemic caused shifts in load across all major customer sectors.
14 The differences in load relative to the March 2020 Load Forecast for COVID-19
15 Scenarios A and B are provided in [Table D-1](#) below.

**Table D-1 COVID-19 Scenarios Difference from
March 2020 Reference Case**

Billed Sales Projections - After Rate Impacts and after Demand-Side Management ¹						
Fiscal Year	Main Customer Sectors ¹					
	Residential Sales (GWh)	Commercial Sales (GWh)	Light Industrial Sales (GWh)	Large Industrial Sales (GWh)	Change in Domestic Sales (GWh)	Change in Domestic Sales (%)
COVID-19 Scenario A Relative to March 2020 Forecast						
F2021	454	-1,138	-505	-2,015	-3,204	-6
F2022	0	0	-457	-1,126	-1,582	-3
F2023	0	0	-458	-887	-1,346	-2
F2024	0	0	0	-790	-790	-1
F2025	0	0	0	-790	-790	-1
COVID-19 Scenario B Relative to March 2020 Forecast						
F2021	607	-3,259	-680	-3,294	-6,626	-12
F2022	187	-1,626	-768	-4,918	-7,124	-13
F2023	-295	-734	-809	-2,963	-4,801	-9
F2024	0	0	0	-790	-790	-1
F2025	0	0	0	-790	-790	-1

1. Changes were made to reflect impacts to major customer sectors. No changes were made to other loads (Street Lighting, Irrigation, sales to the City of New Westminster, FortisBC Inc., Seattle City Light, Hyder Alaska, etc.)

The above table shows significant load reduction in the short-term followed by a persistent 1.0 per cent reduction relative to the March 2020 Load Forecast in both scenarios. For fiscal 2022, Scenario A assumes a reduction of 3.0 per cent relative to the March 2020 Load Forecast and Scenario B assumes a relative reduction of 13.0 per cent.

At the time of development of the COVID-19 scenarios, the consensus among economic experts was that the pandemic would have effects in calendar year 2020 (fiscal 2021) followed by a recovery to pre-pandemic levels in a year or two. As a result, both scenarios assumed a return to 1.0 per cent below the March 2020 Load Forecast by fiscal 2024. Now that we are further along in the pandemic, we expect this recovery to be more gradual than what is shown for both the COVID-19

-
- 1 scenarios in [Table D-1](#) above. This more gradual recovery will be reflected in future
 - 2 load forecasts.

15 Glossary

Accrued Sales are an estimate of electricity delivered within a specific month. Most customer meters are not read at every month-end, so the amount of electricity delivered in a month is not known precisely. In accordance with GAAP, monthly accrued sales are used for monthly financial reporting.

Billed Sales are the amount of electricity billed. Because bills are produced after the electricity has been delivered, monthly billed sales lag monthly delivery of electricity.

Calibration Estimating econometric or other models over a historical time period.

Consumer Price Index (CPI) represents changes in prices as experienced by consumers. It measures price change by comparing, through time, the cost of a fixed basket of goods and services.

Cooling Degree Day (CDD) is a measure of warmth, defined by the number of degrees above a certain daily average temperature measured in Degrees Celsius. CDDs are drivers of utility air-conditioning electricity loads.

Demand-Side Management (DSM) Activities that occur on the demand side of the revenue meter and are influenced by the utility. Demand-Side Management activities result in a change in electricity sales. Past Demand-Side Management savings include incremental load displacement and energy efficiency savings. Note that BC Hydro's historical sales include the impact of Demand-Side Management savings realized up to that year.

Econometric Modelling The use of statistical techniques, typically regression analysis of time-series and/or cross-sectional data, to detect statistically verifiable relationships, coherent with economic theory, between an explained variable (e.g. electricity consumption) and explanatory variables (e.g., industry output, prices of alternative energy inputs and GDP).

Elasticity The proportionate change in a dependent variable (e.g. electricity consumption) divided by the proportionate change in a specified independent variable (e.g. electricity price). A dependent variable is highly elastic with respect to a given independent variable if the calculated elasticity is much greater than one. The dependent variable is inelastic if the elasticity is less than one.

Energy The amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200-watt hours in two hours.

EV Electric Vehicle

Fuel Switching is specific to the March 2020 forecast as presented in this report. Fuel switching means switching from one kind of energy source or use to another that decreases GHG emissions in B.C., and the estimated fuel switching load included in the March 2020 forecast is based on specific government or BC Hydro programs that incent customers to switch from fossil fuel-based energy to clean electricity.

GAAP Generally Accepted Accounting Principles.

Gigawatt-hour (GWh) A measure of electrical energy, equivalent to one million kilowatt-hours. (See Units of Measure).

Gross Domestic Product (GDP) A measure of the total flow of goods and services produced by the economy over a specified time period, normally a year or quarter. It is obtained by valuing outputs of goods and services at market prices (alternatively at factor cost), and then aggregating the total of all goods and services.

Heating Degree Day (HDD) Is a measure of coldness, defined by the number of degrees below a certain daily average temperature measured in Degrees Celsius. HDDs are drivers of utility space heating electricity loads.

1 **Integrated System** That portion of the BC Hydro's electricity system which is
2 connected as one whole by a high voltage transmission grid.

3 **Integrated System Peak** includes the peak requirements for BC Hydro's distribution
4 and transmission customers in its service territory; sales to Other Utilities, which
5 includes Seattle City Light, New Westminster, FortisBC Inc. and Hyder Alaska
6 (Tongass Power and Light Co. Inc.); and system transmission and distribution
7 losses.

8 **Intensity** A unitized measure of energy consumption, typically in kilowatt-hours per
9 unit of stock. For example, intensity is kWh per account in the residential sector or
10 kWh per unit of production in the industrial sector.

11 **Kilowatt (kW)** A kW is 1000 watts and a watt is measure of power that can be
12 transferred instantaneously.

13 **Kilowatt-hour (kWh)** A measure of electrical energy over a period of time,
14 equivalent to the energy consumed by a 100-watt bulb in 10 hours. (See Units of
15 Measure)

16 **Liquefied Natural Gas (LNG)** is natural gas that has been converted temporarily to
17 liquid form for ease of storage or transport. This process involves refrigeration and
18 requires no chemical transformations.

19 **Load** The total amount of electrical power demanded by the utility's customers at
20 any given time, typically measured in megawatts.

21 **Megawatt (MW)** A unit used to measure the capacity or potential to generate or
22 consume electricity. One MW equals one million watts. (See Units of Measure)

23 **Megawatt-hour (MWh)** A measure of electrical energy, equivalent to 1,000 kWh.
24 (See Units of Measure)

Monte Carlo Method A technique for estimating probabilities involving the construction of a model and the simulation of the outcome of an activity a large number of times. Random sampling techniques are used to generate a range of outcomes. Probabilities are estimated from an analysis of this range of outcomes.

Non-Integrated Area (NIA) Non-integrated facilities refer to generating facilities that are not connected to the system, located in remote areas of the province.

Normalization The correction of actual customer sales and peak demand for factors such as unusually warm or cold weather.

Price Elasticity of Demand The percentage change in quantity demanded, divided by the percentage change in price that caused the change in quantity demanded.

Real Price Increases that have been adjusted for changes in prices of all goods. The nominal price of an item may rise by 10 per cent over a year, but inflation (and assumed wages) may have risen by 7 per cent over the same time period. Therefore, the effective price increase faced by the consumer is close to 3 per cent. It is necessary to deflate current prices by an appropriate inflation index (the CPI in Canada) to convert money values to constant prices or real terms.

Region A geographical sub-division of the BC Hydro service area used for Load Forecast purposes. Four regions exist: Lower Mainland, Vancouver Island, South Interior and the Northern Region.

Stock A quantity representing a number of energy consuming units. For example, in the residential sector, stock is the number of accounts or housing units; in the commercial sector, stock is represented by the floor area of commercial building space.

Transmission Voltage Customer A BC Hydro customer that is supplied its electricity via high-voltage transmission lines (60 kV or above).

-
- 1 **Units of Measure** The large amounts of electricity generated and consumed on a
2 system-wide basis are discussed in multiples of the basic units of watts and
3 watt-hours. Kilowatts and megawatts are used to measure power, and
4 kilowatt-hours, megawatt-hours, and gigawatt-hours are used to measure energy.
5 The equivalence is:

1 kilowatt (kW)	= 1,000 watts
1 megawatt (MW)	= 1,000 kilowatts or 1 million watts
1 kilowatt-hour (kWh)	= 1,000 watt-hours
1 megawatt-hour (MWh)	= 1,000 kilowatt-hours or 1 million watt-hours
1 gigawatt-hour (GWh)	= 1,000 megawatt-hours or 1 billion watt-hours

BC Hydro Fiscal 2022
Revenue Requirements Application

Appendix E
Fiscal 2021 to Fiscal 2030 Capital Plan

2.3 Annual 10 Year Capital Plan (incl. capital budgets)

Executive summary

This briefing provides a summary of BC Hydro's updated Capital Plan (Capital Plan) with an outline of the Enterprise Capital Planning process, the overall Capital Plan composition, as well as retained risks and uncertainties across the portfolio. The Capital Plan is presented to the Capital Projects Committee of the Board of Directors annually, and supports BC Hydro's Service Plan update.

This Capital Plan has returned to 10 years of investment level detail, was developed through the application of BC Hydro's strategies, plans and studies, and is aligned with strategic direction, capital additions and depreciation targets. The Enterprise Capital Planning Working Group focused on collaboration across Plan, Build, Operate, and Support to develop the Capital Plan, as well as to understand the portfolio level adjustments required to achieve the targets. Funding re-direction within the Enterprise Portfolio was required to support changing needs within the Technology, Properties, and Fleet Services portfolios.

Given the April 1, 2019 currency date¹ of the Capital Plan, the June 2019 Load Forecast was not fully incorporated into this capital planning cycle. Preliminary Load Forecast information was used to adjust the level of growth expenditures in this Capital Plan, and the full impacts of the updated load forecast on long term planning projections will be incorporated in the next capital planning cycle. Expenditures related to CleanBC and the Revelstoke Unit 6 projects have been included in the Capital Plan to the current approved funding phase; Identification for the three CleanBC projects, and Definition for Revelstoke Unit 6. These will be adjusted in next year's capital planning cycle pending decisions to advance to subsequent project phases.

This Capital Plan continues to balance affordability for BC Hydro customers with an appropriate level of investment in system growth, asset sustainment and risk mitigation, while supporting the delivery of reliable, affordable, clean electricity throughout BC safely.

Background

This fiscal's capital planning processes ran in parallel with two regulatory processes, the F2020 – F2021 Revenue Requirements Application, and the Capital Expenditure and Projects Review, which required balancing resource requirements with the capital planning process. In order to meet all regulatory and capital planning deadlines, prioritization and peer reviews were focused on validating whether we were accepting a similar level of retained risk across our assets. The Enterprise Portfolio was adjusted to calibrate the retained risks while achieving the capital additions and amortization targets.

Enterprise Capital Planning Process

The F2021 – F2030 Enterprise Capital Planning process began with defining business group level capital additions targets. Initial targets were set based on the F2020 – F2024 Capital Plan (Previous Plan) plus the high level projections established for F2025 – F2029 in spring 2018. To set the F2030 target for Fleet Services, Technology, and Properties, a 2% inflationary adjustment was added to F2029. To set the Power System² F2030 target, a different approach was used because several large investments are planned to be put in-service in F2029, which created an unreasonable F2030 target. The Power System F2030 target is aligned with the F2025 – F2028 average plus inflationary

¹ April 1, 2019 is the currency date of active projects within Integrated Planning and Properties. The currency date for Technology's active projects is July 1, 2019.

² Power System assets consist of Dams, Generating Stations, Substations, and Transmission & Distribution Lines.

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2.3 Annual 10 Year Capital Plan (incl. capital budgets)

adjustment. These targets are in line with the executive level strategic direction received during F2020 – F2024 Enterprise Capital Planning, and were presented to the Executive Team on April 30, 2019 for endorsement.

The next step in the development of the Enterprise Capital Plan was bottom up planning within the various business groups. Each business group identified investments to address asset needs and risks, while applying the enterprise-wide framework for capital prioritization and considering any labour and financial constraints.

Once bottom up planning and business group portfolio planning concluded, prioritization and peer reviews were conducted in the form of portfolio reviews and discussions on re-direction within the overall Enterprise targets. A total of \$172 million in capital additions were re-directed across Technology, Properties, Fleet Services, and the Tools/Other portfolio to address changes in business driven needs. Increasing the capital additions targets of the Supporting Portfolios created an amortization pressure due to the shift in funding to assets with shorter lifecycles. In addition, dismantling expenditures were forecast to increase over the Previous Plan. To account for the rate impacts of increasing amortization and dismantling, the Power System capital additions were decreased by approximately \$1 billion over 10 years to remain neutral on the forecast rate impacts of the capital plan.

Capital Investment Drivers

The following list includes the main drivers for investments within the capital plan, which are common across the business:

Ageing Assets – A large portion of BC Hydro's system was built in the 1960s and 1970s and is reaching or exceeding expected end-of-life. A significant proportion of the risks facing BC Hydro's major assets can be attributed to their age. The physical condition, performance, maintenance history, and criticality of equipment and facilities are significant drivers for planning and prioritizing refurbishment or replacement.

Reliability – The reliability of BC Hydro's assets (e.g. equipment associated with the power system, Properties, Technology, and Fleet assets) can be measured over time. Asset health ratings at each point in time are reflective of the condition of the assets, maintenance practices and long-term investment trends. Additional information on the Asset Health Ratings for Power System assets can be found in the F2020 Annual Review of Asset Health briefing note. Long term trends indicate increasing or declining reliability risk for use in asset management.

Capital investment is paramount to the total performance of the system. The indicators of investment adequacy are consistent performance metrics over time and the number and impact of in-service failures on critical assets. The BC Hydro Service Plan sets targets for system performance measures based on longer term trends and expected long-term investment plans; these lagging indicators continue to show that BC Hydro is appropriately managing our system performance. While current year reliability performance is trending higher (worse) than targets, it is being monitored and the performance is not outside the expected annual variability. As a result, it will not immediately drive new capital investments. Additional information on the historical performance of BC Hydro's performance metrics can be found in the F2020 Annual Review of Asset Health briefing note.

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Growth – Capital investment in growth can be sub-divided into four categories:

1. **Load Forecast:** expansion and reinforcement of the transmission and distribution system in areas experiencing load growth.
2. **Customer Connections:** transmission and distribution infrastructure changes/additions to facilitate new customer connections.
3. **Transfer Capacity:** reinforcement of the transmission system to increase transfer capacity for new generation.
4. **Other System Risk Mitigation:** expansion of the transmission and distribution system to provide reliable service and/or allow for the retirement of assets. These growth investments improve the reliability of the system or reduce the need for continued sustaining investment in assets that are at or approaching end of life. Examples include the construction of a new line to West Kelowna and a new substation in the West End of Vancouver to allow for the offloading of Dal Grauer substation.

While the overall level of investment in growth has moderated over the past few years, aligning with the trend in the load forecast, new investments continue to be required for both distribution and transmission infrastructure to meet regional customer demand growth and to connect new supply of electricity.

Business Needs – Changes in work methods, the increasing prevalence of technology, and changes in work spaces to support employee needs drive some of the investments associated with the Supporting Portfolios: Fleet Services, Technology, Properties, and Tools/Other. Investment in these changes supports the BC Hydro wide initiative to “make it easier to get work done.”

Prioritization Methodology

The investments in the Capital Plan have been assessed and scored in accordance with the enterprise-wide framework for capital prioritization, to ensure BC Hydro is appropriately mitigating asset-related risks. Dependencies between projects, opportunities to bundle work for more efficient delivery, resource considerations, as well as the risk or value score are some of the factors that are also considered to ensure each Business Group's portfolio of investments aligns with strategic and performance objectives, as well as with planning targets.

The enterprise-wide framework for capital prioritization describes the assessment and prioritization process for all proposed capital projects that are well defined. Projects are prioritized based on their primary driver:

- Capital projects that primarily mitigate risk are scored for prioritization using a methodology that is aligned with the BC Hydro Corporate Risk Matrix.
- Capital projects that primarily create value are scored for prioritization using a net present value per dollar invested metric. The value prioritization is mainly used for some capital expenditures in the Technology Portfolio.

The framework classifies capital investments into one of three categories:

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- Mandatory investments driven by legal and regulatory requirements.
- Committed investments not to be postponed. This category includes projects that are economically unreasonable to stop as deferral of these projects would result in significant additional costs to suspend and then restart at a later date and may result in the loss of warranty protection on major equipment.
- Investments to be prioritized, including projects that will be in the Identification or Definition phase by F2020, and could be re-prioritized without significant economic losses.

Composition of the Plan

BC Hydro is forecasting net annual average capital expenditures of approximately \$1.63 billion³ per year or total net capital expenditures of \$16.34 billion³ over F2021 – F2030. For capital additions, BC Hydro is forecasting a net annual average of approximately \$1.56 billion³ per year, or total net capital additions of \$15.62 billion³ over F2021 – F2030. Figures 1 and 2 below show the capital expenditures and additions breakdown across the Enterprise Portfolio.

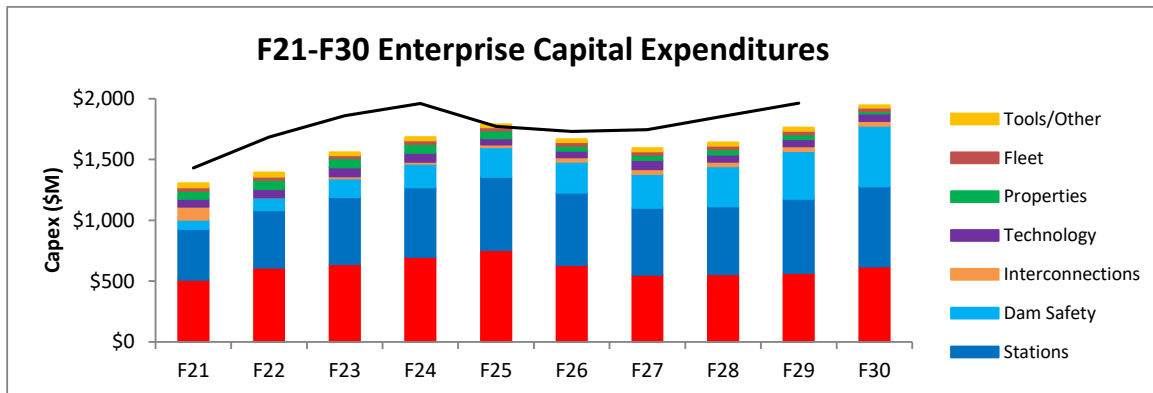


Figure 1: F2021 – F2030 Capital Expenditure

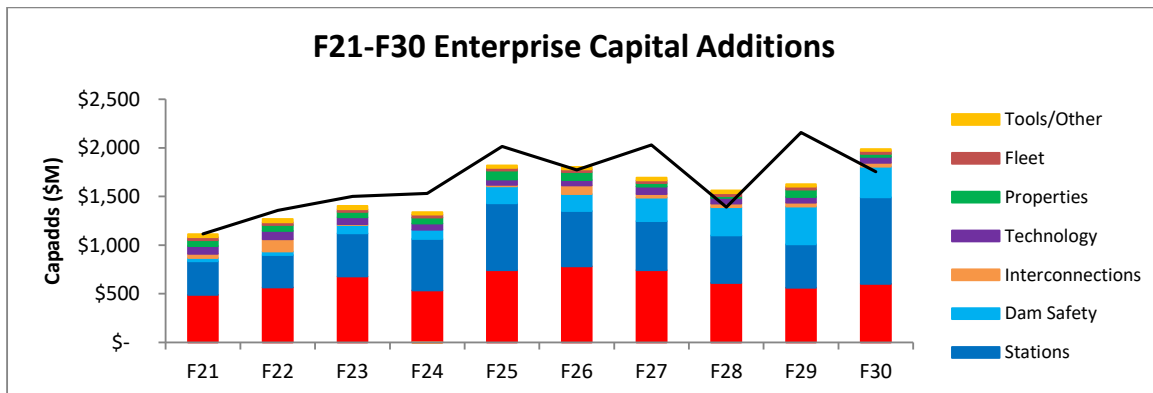


Figure 2: F2021 – F2030 Capital Additions

³ Excludes Site C.

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This Capital Plan aligns with BC Hydro's strategic goal of keeping electricity rates affordable for our customers, while supporting the delivery of reliable, clean electricity throughout BC safely. System growth, asset sustainment and other investments are appropriately balanced, given the information available at the time of the development.

Figure 3 below compares the F2021 – F2030 capital additions (un-risk adjusted) for growth, dam safety, and sustaining existing assets. This chart shows that with the moderation in the rate of load growth and the aging asset base, BC Hydro is experiencing a shift in the portfolio composition with the majority of investments in sustainment.

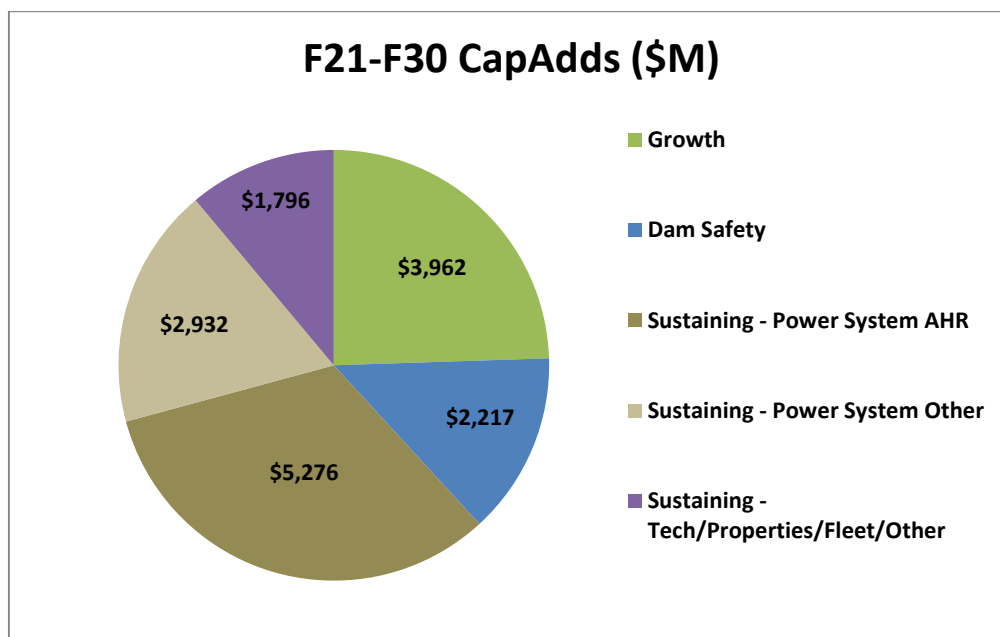


Figure 3: F2021 – F2030 Capital Additions by Type

Since the currency date of the Capital Plan, the 20 Year load forecast has been published and a new 10-Year rate forecast is anticipated in January 2020. This information, as well as any outcomes from the Comprehensive Review, will be incorporated into the next capital planning cycle.

Power System

After capital additions targets were set at the Enterprise Portfolio level, the Power System targets were set for each sub-portfolio. Cross portfolio reviews focused on ensuring the retained risks were comparable across the Power System. The Capital Plan was developed with supporting input from Operations and Capital Infrastructure Project Delivery, such as updated forecasts for continuing projects and resource modelling to ensure that the plan is deliverable given current internal and external resource capacity. Over the next five years BC Hydro's capital expenditures are expected to increase with a return to historical levels. This increase will require specific resource and contracting strategies to be in place for critical resources including trades such as CPC technicians and engineering disciplines such as station electrical and P&C designers.

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Dam Safety

Dam Safety risk reduction targets remain as they were in previous Plans and align with the approach that was approved by the Board in 2014: to “*manage the whole fleet of dams so that there is no significant deterioration in the risk position and that the overall level of risk is kept well within the limits considered to be tolerable.*” In practical terms, this Capital Plan aims to reduce the aggregated Vulnerability Index of issues identified in the Dam Safety Issues Database at a rate that will generally offset the historic (and expected) rate of additions to the Vulnerability Index through newly identified or understood issues.

This Capital Plan provides for major seismic and spillway gate reliability upgrades to the Campbell River System and Mica Dam spillway, seismic upgrades to La Joie Dam and the Alouette-Stave tunnel, and provides for flow control improvements and associated reduction of public safety risk along the Puntledge River. This Capital Plan is right-sized to prevent deterioration of the current risk profile related to BC Hydro’s dams and reservoirs and will address several issues that significantly contribute to that risk.

No active deferrals were made to the Dam Safety portfolio of projects, however some planned Dam Safety project cash flows were re-curved to better align with the expected staging of the work at Waneta. This will allow for detailed investigations to be completed, supporting the initiation of those projects. In addition, the Wilsey Dam Seismic Upgrade project was removed from the plan to align with the updated Shuswap Facility Asset Plan, wherein decommissioning of the Shuswap Generating Station and Wilsey Dam are contemplated. A decommissioning project has been initiated for Shuswap through the Stations portfolio, and Dam Safety is continuing with deficiency investigation work at Wilsey Dam to support that project’s business case.

The current Capital Plan addresses the same Dam Safety risks over the course of the next ten years as did the previous plan. In the interim, the risks related to these works will continue to be managed in the same manner as at present: in the case of Campbell River, by continued public outreach, education and coordination with local authorities, and in the case of La Joie by managing the reservoir to a lower elevation. Risks that are being retained at other dam and reservoir sites—both for those that are to be addressed within this Capital Plan and those that are to be addressed at a later date—will be managed, as warranted and practicable, by similar methods documented in each dams’ Operation, Maintenance and Surveillance Manuals or supplemental Interim Dam Safety Risk Management Plans.

Generating Stations

BC Hydro has 30 hydroelectric, two thermal generating stations, and one synchronous condenser station. This includes a total of 89 units, and 79 dams and civil structures. BC Hydro’s generation facilities are divided into three categories of criticality to help focus asset management efforts: Key, Strategic, and Available Energy facilities.⁴

The Generation portion of the Stations Asset Planning portfolio continues to focus on the largest and most critical generating facilities, the Key facilities, as well as water management in the Bridge River System. The investment strategy has focused on preserving a high level of reliability at the Key facilities

⁴ The seven Key Generating Facilities represent those with installed capacity greater than 200 MW and provide 90% of the average annual electricity generated by BC Hydro. The 18 Strategic Facilities represent 9% of the average annual electricity generated by BC Hydro. The seven remaining facilities are known as Available Energy Generating Facilities and provide 1% of the average annual electricity generated.

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given their critical role in the fleet, with a focus being placed on the three largest facilities (GM Shrum, Mica and Revelstoke). Bridge River is the smallest of the Key facilities, and is now receiving an increased level of investment to address a number of asset condition and reliability concerns. Overall, the condition of the Generation assets is expected to improve over the capital planning horizon.

In considering the balance between affordability, system performance and risk, we have delayed specific investments at Key facilities by 1 to 2 years (e.g. GMS 9 & 10 Turbines), reduced investment in reliability projects at Strategic and Available Energy facilities (for example the Clowhom Powerhouse Crane Upgrade, Clowhom Unit Upgrade and Ladore Unit Two Re-development projects have been deferred by three years), and we have reduced the Generation corrective capital provision.

As a result of these investment deferrals the following retained risks are anticipated:

- Increased reliability risk at less critical Strategic and Available Energy generation facilities (accounting for less than 5% of annual energy).
- Retention of out of service assets, such as Elko, which will be made safe but will not be demolished/removed proactively.
- Lack of flexibility within the plan to address emerging corrective issues such as increasing funding to the Crane Program, and the Mica Townsite Investment Strategy – both strategies are currently under review.

The health of the assets will be monitored over time through regular condition assessments and on-going maintenance. Changes in asset condition will trigger review of the investment strategy and may result in a reactive investment decision or operational change in order to manage an emerging risk.

Substations

The investment strategy of the Substation portion of the Stations Asset Planning portfolio focuses on the replacement of highest priority asset classes such as transformers, circuit breakers, and feeder section retrofits at the most critical substations on the system. Due to a moderation in the rate of load growth, the portfolio has an increased focus on sustainment investments. A number of station rebuilds and upgrade projects are also planned that will facilitate the removal of end-of-life equipment and future load growth. The portfolio includes the required funding to adhere to federal statutory requirements to remove equipment that contains more than 50 ppm⁵ of polychlorinated biphenyls (PCBs) by the December 31, 2025 deadline. Future planning cycles will continue to ensure that adequate funding is available to adhere to the 2025 deadline.

Deferrals in the Substation portfolio are focused on a few major area Growth projects such as supply to the Maple Ridge / Haney area and the purchase of a strategic property for a new station in Metrotown. As a result of these investment deferrals the following retained risks are anticipated:

- Increased risk of un-served load due to load growth materializing faster than anticipated.
- Some overall degradation in the condition of assets, which is not expected to materially impact customer reliability given the asset redundancy within the system.

⁵ parts per million

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- Longer retention of end-of-life equipment with known limits of approach issues.

These risks will be managed by transferring load between neighboring stations where possible, but may require re-prioritization of the plan outside of the normal planning cycle to address any emerging load growth needs or increased asset failures. Risks associated with known limits of approach issues will continue to be managed through established operational work procedures.

Transmission and Distribution Lines

Capital investments in Transmission & Distribution lines are focused on preserving the asset health and reliability on the bulk electric system, increasing capacity on the transmission system, and maintaining system safety and reliability on the distribution system.

Investments in sustaining capital maintain a reliable Transmission & Distribution system, meet regulatory compliance requirements, and mitigate the highest asset risks including life-safety, environmental, extreme weather, seismic, and fire. Expenditures in this portfolio will replace end-of-life assets and manage reliability trends on the system. Most of the sustain expenditures are for the replacement of component parts (e.g. transmission and distribution wood poles) with varied life expectancies. Bottom-up planning following the asset strategies was used to identify the investments required to sustain the most critical assets, and address the highest asset risks. The portfolio also includes the required funding to adhere to federal deadlines regarding the removal of PCB equipment that contains more than 50 ppm by the December 31 2025 deadline.

Customer reliability expenditures are also part of the Sustaining Capital Portfolio. These expenditures contribute to maintaining the overall system reliability by installing automated devices such as circuit reclosers, and by targeting the distribution circuits that are performing poorly. The scope of customer reliability projects may include new standby feeders, feeder ties, circuit undergrounding or reconfiguration, line relocations and protection upgrades. We are investing in automated distribution devices to support BC Hydro's Grid Modernization efforts, providing operating personnel with remote visibility of system parameters and system status, facilitating remote operability, and enabling greater flexibility to efficiently operate the system.

In considering the balance between affordability, system performance and risk the following sustainment investments were deferred:

- Cable Replacement – 2L051 Como Lake Substation to Barnard Substation
- Dewdney Trunk Copper Conductor Replacement project
- Telecom System Resiliency Program
- Long-Span Replacement – 2L048 Jervis Inlet and Agamemnon Crossings
- Transmission and Distribution Sustainment program funding reductions

As a result of these investment deferrals the following retained risks are anticipated:

- Some overall degradation in condition of assets that can be quickly returned to service with lower impact to customers.

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- Retention of reliability risks, including increasing outage frequency and duration.
- Potential for increased corrective maintenance and emergency capital.

These risks will be mitigated through monitoring of the health of the assets over time, through regular condition assessments and on-going maintenance activities. In addition, continued installation of automated devices is expected to maintain system performance and lessen the customer reliability impact of asset failures. Where changes are observed or risks emerge, decisions will be made with respect to the investment strategy and where necessary, short term operational changes.

Impact of Load Forecast

While a 20-Year Load Forecast has been completed, due to timing only preliminary information could be incorporated into this Capital Plan. This information allowed for the re-evaluation of the need for the following investments:

- Interior to Lower Mainland – Remedial Action Schemes
- South Vancouver Island – Reactor Addition
- The growth portion of the Peace to Kelly Lake Capacitors project

These growth investments have been removed from the Capital Plan, and no retained risks are anticipated. The capital plan includes growth-driven investments to support CleanBC initiatives through new feeders or system upgrades to supply additional load. These initiatives include:

- Low Carbon Electrification (converting industrial and commercial customer loads from fossil burning fuels) – minor capital system upgrades such as transformers
- Electric vehicle charging infrastructure – locating and assessing distribution feeder capacity to connect charging stations
- BC Ferries Electrification – locating and assessing distribution feeder capacity to connect charging stations for new electric ferries.
- Shore Power – locating and assessing distribution feeder capacity to provide shore power for cruise ships.
- BC Transit electric charging stations – locating and assessing distribution feeder capacity to connect charging stations for new electric transit fleet vehicles.

A full analysis of the impact of the 20-Year Load Forecast on the growth investments in the 10-Year Capital Plan will be completed during the next capital planning cycle.

Technology

This Capital Plan provides appropriate investment in technology assets in F2021 – F2024 to manage compliance and security, manage risk, and sustain productivity. The current portfolio includes a number of mid-sized sustainment and business enablement investments being made as a result of the decision to redirect funding to Technology. These investments include the Asset Investment Planning Tool,

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Legal Services Information Management System, Mobility Application Platform, Integration of Mobility and Enterprise Applications, Contact Centre Stack Replacement and SharePoint Workspaces Upgrade.

Large initiatives will require additional funding supported by appropriate cost-benefit analysis indicating realizable net benefits. This includes large investments such as Work and Asset Management, Distribution Design Replacement, and a Virtual Analytics Platform. In addition, we are currently assessing the recommendations of the recently published Office of the Auditor General Audit for mitigation of cyber security risks. Investments required to address the audit recommendations will be included in future capital plans.

The Technology capital plan in F2025 – F2031 is less defined due to the dynamic nature of the investment needs. It is currently below historical levels which increases the risk that organizational technology needs will not be fully met. This risk will be mitigated through continued evaluation of needs and investment options, discussions on re-direction of funding in future capital planning cycles, and initiation of ex-plan projects where required.

Properties

The Properties capital plan continues to focus on supporting operational requirements of the business. This includes safety and seismic reinforcement across the 100+ building portfolio, with particular emphasis on our largest and highest criticality facilities. Seven out of the eight high criticality, large field offices have been redeveloped, including operations yards, warehouses, truck bays, security and IT infrastructure, office areas, as well as seismic upgrades. In the last nine years approximately 67% of our building space has been redeveloped or renovated, impacting about half of our field staff, and the majority of our corporate headquarters staff.

Going forward, Properties will replace the final high criticality large field office in Kamloops. As well, field building replacement projects and operational upgrades will be undertaken at the medium criticality facilities in high risk seismic regions and/or where required for business needs (including Materials Classification Facility in Surrey, and the field offices in Duncan, Chilliwack, Campbell River, and North Vancouver). Properties will also continue to invest in upgrades to critical end of life building assets (e.g. roofs, HVAC systems) as well as a modest number of field building interior upgrades and construction/expansion of truck bay facilities to meet changing operational requirements. A further 16% of our facility space will be redeveloped or renovated in this 10 year plan in 18 redevelopment and renovation projects, bringing the total redeveloped or renovated space to 83% by F2030. At the end of this 10 year Capital Plan, we will have addressed seismic requirements in all high criticality facilities with the poorest seismic withstand capabilities.

Retained risks related to aging assets will be managed through the focus on larger and higher criticality facilities and systems where asset failure would have the greatest impact.

Fleet Services

Fleet assets⁶ are integral to the maintenance and repair of BC Hydro infrastructure and support the delivery of capital projects. Despite routine preventative maintenance, fleet assets inevitably deteriorate

⁶ Includes vehicles, equipment, and trailers.

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2.3 Annual 10 Year Capital Plan (incl. capital budgets)

as they age and eventually reach end-of-life. The Fleet Services capital program is a continuous sustainment program to replenish fleet assets and support safe, efficient operations.

Under this Capital Plan, approximately 513 assets will be replaced by the end of F2024. This plan does not include sufficient capital to replace all assets forecast to reach end-of-life during this period, based on existing replacement criteria. As a result, the backlog of units deferred for replacement will continue to grow from approximately 86 units in F2020 with an estimated replacement value of \$9.8M, to approximately 215 units by the end of F2024 with an estimated replacement value of \$26.3M. With these deferred replacements, the fleet assets will continue to age and deteriorate during the plan period.

The plan also does not include funding for net additions or for significant upgrades to the fleet that may be required by the business due to changes in engineering standards, greening the fleet, work methods, staffing or operational priorities. These requests would need to be funded via approval of ex-plan capital, or absorbed into the existing Fleet Services capital budget through deferral. The plan also does not include funding for new technologies, the Vehicle Frontline Alliance Team (VFLAT) outcomes, electric vehicles or any other GHG-related initiatives.

As a result of these investment decisions, the following retained risks are anticipated:

- Increase in Fleet OMA due to repairs, (estimated at ~\$6.9M between F2020-F2024).
- Increase in vehicle downtime, resulting in decreased productivity & efficiency, less operational flexibility and possible impacts to crew response time.
- Reduced flexibility to address cost pressures in the Fleet Services capital plan associated with exchange rate fluctuations and the adoption of new fleet technologies (e.g. alternative fuels).

While additional funding in the Fleet Services portfolio will be required to address the significant increase in backlog of end-of-life replacements, the following initiatives/strategies are being implemented to mitigate the portfolio's retained risks: implementation of Telematics⁷ to assist in optimizing fleet asset life cycles, updates to vehicle/financial policies such as vehicle assignment criteria, re-allocation of low-utilization assets, the creation of vehicle pools in more locations, fleet standardization, and the continuation of VFLAT which focuses on improving Fleet processes and providing the user groups the right vehicle for their job.

Tools/Other

This Portfolio is comprised of capital investments from various departments across BC Hydro to support corporate driven initiatives, as well as smaller capital needs from departments such as Security, Safety, Materials Management, Learning, Development & Trades Training, Environment, Engineering, Corporate Affairs, Site Engineering & Acceptance as well as Field Operations tools.

⁷ Telematics: the installation of technology within Fleet vehicles to allow for the collection of vehicle data for analysis of key metrics such as good idling vs bad idling, hard/extreme breaking/acceleration, utilization and real time vehicle diagnostics.

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2.3 Annual 10 Year Capital Plan (incl. capital budgets)

Attachments

Capital Expenditures & Additions F2021-F2030

Current 10 Year Capital Expenditure Forecast

Consolidated by Asset Owner

	Forecast	Plan										F21-F30	F21-F30
ESTIMATED CAPITAL EXPENDITURES *	F20	F21	F22	F23	F24	F25	F26	F27	F28	F29	F30	10 Yr Total	10 Yr Avg.
Sustaining													
Generation	279.9	346.6	383.4	420.0	486.5	562.5	567.2	564.6	601.9	671.9	891.9	5,496.5	549.6
Generation - Waneta												-	-
Transmission	232.0	270.3	325.6	401.8	327.4	335.2	236.4	205.3	205.5	212.2	246.2	2,765.8	276.6
Distribution	207.0	175.9	219.3	229.3	208.1	233.9	246.8	242.2	260.1	261.2	277.9	2,354.6	235.5
Support Services - Technology	102.1	66.2	68.9	73.3	73.6	53.3	54.8	76.5	58.1	59.9	61.7	646.3	64.6
Support Services - Properties	63.6	65.1	75.6	76.2	72.8	62.1	41.0	42.8	44.9	38.2	19.8	538.4	53.8
Support Services - Other & Subsidiaries	79.2	79.6	72.5	57.9	65.7	58.9	66.5	66.3	66.2	66.3	89.1	689.2	68.9
Subtotal - Sustaining	963.9	1,003.7	1,145.3	1,258.5	1,234.1	1,305.9	1,212.7	1,197.7	1,236.7	1,309.6	1,586.6	12,490.8	1,249.1
Growth													
Generation	3.4	4.6	5.0	6.4	-	-	-	-	1.0	4.1	5.7	26.7	2.7
Generation - Site C Project	1,594.0	1,626.0	1,361.0	1,177.0	926.0	286.0	3.0	-	-	-	-	5,379.0	537.9
Generation - Waneta												-	-
Transmission	158.1	101.2	142.9	212.4	357.1	358.7	342.6	290.6	291.4	321.6	229.4	2,647.9	264.8
Distribution	321.5	343.2	306.7	247.7	260.4	294.4	283.1	279.7	290.8	308.2	310.7	2,924.9	292.5
Support Services - Other & Subsidiaries	3.8	13.3	8.7	2.7	2.7	2.7	3.0	3.0	3.0	3.0	3.0	45.0	4.5
Subtotal - Growth	2,080.8	2,088.3	1,824.3	1,646.2	1,546.2	941.8	631.7	573.2	586.2	636.8	548.7	11,023.6	1,102.4
Total before Contribution In Aid (CIA)	3,044.7	3,092.0	2,969.6	2,904.8	2,780.3	2,247.6	1,844.4	1,770.9	1,823.0	1,946.4	2,135.3	23,514.3	2,351.4
Generation - Sustaining												-	-
Generation - Growth												-	-
Transmission - Sustaining	(8.2)	(5.2)	(5.3)	(5.4)	(5.5)	(5.7)	(5.8)	(5.9)	(6.0)	(6.1)	(6.2)	(57.2)	(5.7)
Transmission - Growth	(7.5)	(5.9)	(8.7)	(8.6)	(10.1)	(8.7)	(8.7)	(8.9)	(9.1)	(9.3)	(9.5)	(87.5)	(8.7)
Distribution - Sustaining	(2.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(9.3)	(0.9)
Distribution - Growth	(150.3)	(147.7)	(199.4)	(151.8)	(154.2)	(156.6)	(159.2)	(162.0)	(165.4)	(168.1)	(170.9)	(1,635.3)	(163.5)
CIA Total	(168.8)	(159.7)	(214.2)	(166.7)	(170.7)	(171.8)	(174.7)	(177.8)	(181.5)	(184.5)	(187.7)	(1,789.3)	(178.9)
Total - including Waneta (\$M)	2,875.9	2,932.3	2,755.4	2,738.1	2,609.6	2,075.8	1,669.8	1,593.1	1,641.5	1,761.9	1,947.6	21,725.1	2,172.5
Less: Waneta												-	-
Total - excluding Waneta (\$M)	2,875.9	2,932.3	2,755.4	2,738.1	2,609.6	2,075.8	1,669.8	1,593.1	1,641.5	1,761.9	1,947.6	21,725.1	2,172.5
less Site C	1,281.90	1,306.3	1,394.4	1,561.1	1,683.6	1,789.8	1,666.8	1,593.1	1,641.5	1,761.9	1,947.6	16,346.1	
ESTIMATED CAPITAL ADDITIONS *													
	Forecast	Plan										F21-F30	F21-F30
	F20	F21	F22	F23	F24	F25	F26	F27	F28	F29	F30	10 Yr Total	10 Yr Avg.
Generation	408.5	244.3	272.4	405.9	385.4	517.8	493.5	552.3	617.4	609.6	616.0	4,714.5	471.4
Generation - Site C Clean Energy	29.0	198.0	-	-	9,248.0	497.0	3.0	-	-	-	-	9,946.0	994.6
Generation - Waneta												-	#DIV/0!
Transmission	183.7	283.7	440.7	434.8	471.4	738.5	747.0	612.1	429.9	432.6	799.8	5,390.6	539.1
Distribution	570.1	524.3	502.9	581.5	460.6	526.5	534.5	525.2	545.5	566.1	585.1	5,352.3	535.2
Support Services - Technology	141.6	87.1	100.3	75.8	71.5	59.5	61.1	82.8	64.4	66.2	68.0	736.4	73.6
Support Services - Properties	76.5	78.4	86.8	72.0	75.1	108.2	100.5	55.2	40.2	95.1	71.0	782.6	78.3
Support Services - Other & Subsidiaries	44.7	61.4	52.8	48.9	44.7	40.7	41.1	42.9	44.8	43.9	38.8	459.9	46.0
Total before CIA	1,454.0	1,477.1	1,455.9	1,618.8	1,075.6	2,488.2	1,980.7	1,870.4	1,742.2	1,813.5	2,178.7	27,382.3	2,738.2
CIA	(158.6)	(165.7)	(187.2)	(216.6)	(170.1)	(171.9)	(174.6)	(177.4)	(181.0)	(184.2)	(187.3)	(1,815.9)	(183.4)
Total - including Waneta (\$M)	1,295.4	1,311.5	1,268.6	1,402.3	1,058.6	2,316.3	1,806.1	1,693.0	1,561.2	1,629.3	1,991.4	25,566.3	2,556.6
Less: Waneta												-	-
Total - excluding Waneta (\$M)	1,295.4	1,311.5	1,268.6	1,402.3	1,058.6	2,316.3	1,806.1	1,693.0	1,561.2	1,629.3	1,991.4	25,566.3	2,556.6
less Site C	1,266.4	1,113.5	1,268.6	1,402.3	1,338.6	1,819.3	1,803.1	1,693.0	1,561.2	1,629.3	1,991.4	\$ 15,620.3	

* 'Capital Expenditures' are recorded when the costs are incurred. 'Capital Additions' refer to when the related asset is placed into service. Certain costs impacting BC Hydro's revenue requirements, such as amortization, return-on-equity, and finance charges, are not recorded until the related asset is placed into service.

Capital Expenditures for Projects > \$50M – F2021-F2030⁸

⁸ Project phase and financial information provided in this table are as of April 1, 2019, the currency date of the F2021-F2030 Capital Plan.

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2.3 Annual 10 Year Capital Plan (incl. capital budgets)

Asset Owner	Project	Type	Phase	Forecasted ISD	Authorized Amount / Engineering Estimate / Latest Forecast
Distribution	Various Sites - LED Street Light Conversion	Sustaining	Identification	TBD	TBD
Generation	Ash River - Woodstave Penstock Replacement	Sustaining	Future	TBD	TBD
Generation	Bennett Dam - Embankment and Spillway Seismic Upgrade	Sustaining	Future	TBD	TBD
Generation	Bridge River - Intake Seismic Withstand Improvement	Sustaining	Future	TBD	TBD
Generation	Cheakamus - Dam Improvements	Sustaining	Future	TBD	TBD
Generation	Clowhom - Unit Upgrade	Sustaining	Future	TBD	TBD
Generation	Duncan Dam - Embankment Dam Improvement	Sustaining	Future	TBD	TBD
Generation	G.M. Shrum - U1 - U5 Capacity Increase	Sustaining	Future	TBD	TBD
Generation	G.M. Shrum - U1, 2, 4, 7, 8, 9, 10 Water Passage Refurbishment	Sustaining	Future	TBD	TBD
Generation	G.M. Shrum - U7 - U8 Stator Replacement	Sustaining	Future	TBD	TBD
Generation	G.M. Shrum - U9 - U10 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	Kootenay Canal - U1 - U4 Generators Refurbishment	Sustaining	Future	TBD	TBD
Generation	Kootenay Canal - U1 - U4 Penstocks Interior and Scroll Cases Recoat	Sustaining	Future	TBD	TBD
Generation	Kootenay Canal - U1 - U4 Turbines Overhaul	Sustaining	Future	TBD	TBD
Generation	Mica - Little Chief Slope Seismic Stability Improvement	Sustaining	Future	TBD	TBD
Generation	Mica - U1 - U2 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	Sustaining	Future	TBD	TBD
Generation	Mica - U3 - U4 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	Peace Canyon - Dam Seismic Upgrade	Sustaining	Future	TBD	TBD
Generation	Puntledge - Comox Dam Upgrade	Sustaining	Future	TBD	TBD
Generation	Puntledge - Woodstave Penstock Replacement and Ground Improvements	Sustaining	Future	TBD	TBD
Generation	Revelstoke - Discharge Gate Systems Reliability Improvements	Sustaining	Future	TBD	TBD
Generation	Revelstoke - U1 - U4 Transformer Replacement	Sustaining	Future	TBD	TBD
Generation	Revelstoke - U1 - U4 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	Seven Mile - U1 - U3 Turbine Upgrade	Sustaining	Future	TBD	TBD
Generation	Strathcona - Embankment Dam Seismic Upgrades	Sustaining	Future	TBD	TBD
Generation	Strathcona - Powerhouse Redevelopment	Sustaining	Future	TBD	TBD
Generation	Terzaghi - Low Level Discharge Reliability Improvement	Sustaining	Future	TBD	TBD
Generation	Waneta - Spillway Gate Reliability	Sustaining	Future	TBD	TBD
Generation	Bridge River 1 - Replace Units 1-4 Generators/Governors	Sustaining	Identification	TBD	TBD
Generation	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	Sustaining	Identification	TBD	TBD
Generation	John Hart - Dam Seismic Upgrade	Sustaining	Identification	TBD	TBD
Generation	Ladore - Spillway Seismic Upgrade	Sustaining	Identification	TBD	TBD
Generation	LaJoie - Dam Improvements	Sustaining	Identification	TBD	TBD
Generation	Mica - Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Identification	TBD	TBD
Generation	Revelstoke - U1 - U4 Stator Replacement	Sustaining	Identification	TBD	TBD
Generation	Strathcona - Upgrade Discharge	Sustaining	Identification	TBD	TBD
Generation	Bridge River 2 - Upgrade Units 7 and 8	Sustaining	Definition	F2022	\$87 - \$68

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Generation	Wahleach Refurbish Generator	Sustaining	Definition	F2022	\$68 - \$22
Generation	Bridge River 2 - Upgrade Units 5 and 6	Sustaining	Implementation	F2020	\$86
Generation	Cheakamus - Units 1 and 2 Generator Replacement	Sustaining	Implementation	F2020	\$74
Generation	G.M. Shrum - G1 to 10 Control System Upgrade	Sustaining	Implementation	F2023	\$75
Generation	Mica - Replace Units 1 to 4 Generator Transformers	Sustaining	Implementation	F2023	\$82
Properties	Kamloops Field Building Redevelopment	Sustaining	Identification	F2025	TBD
Transmission	East Vancouver - Substation Construction	Growth	Future	TBD	TBD
Transmission	Gulf Islands - Transmission Reinforcement	Sustaining	Future	TBD	TBD
Transmission	Richmond - Area Reinforcement (Phase 2)	Growth	Future	TBD	TBD
Transmission	Various Sites - Microwave Radio Replacement	Sustaining	Future	TBD	TBD
Transmission	2L146 - Cable Replacement	Sustaining	Identification	TBD	TBD
Transmission	5L63 Telkwa Relocation	Sustaining	Identification	TBD	TBD
Transmission	Lower Mainland - Capacitive and Reactive Power Reinforcement	Growth	Identification	TBD	TBD
Transmission	Mainwaring Station Upgrade	Sustaining	Identification	TBD	TBD
Transmission	Natal Sub - NTL 60-138 kV Rebuild	Sustaining	Identification	TBD	TBD
Transmission	North Shore Area Transmission Reinforcement	Growth	Identification	TBD	TBD
Transmission	Peace to Kelly Lake Capacitors	Growth	Identification	TBD	TBD
Transmission	West End - Substation Construction and System Reinforcement	Growth	Identification	TBD	TBD
Transmission	West Kelowna Transmission and Westbank Upgrade Projects	Growth	Identification	TBD	TBD
Transmission	Capilano Substation Upgrade	Growth	Definition	F2025	\$88 - \$50
Transmission	Customer B	Growth	Definition	F2026	\$128 - \$68
Transmission	Metro North Transmission (MNT)	Growth	Definition	F2025	\$530 - \$300
Transmission	Mount Lehman Substation Upgrade	Growth	Definition	F2023	\$63 - \$49
Transmission	Customer A	Growth	Implementation	F2021	\$82
Transmission	DVES: West End Strategic Property Purchase	Growth	Implementation	F2021	\$81
Transmission	Fort St. John and Taylor Electric Supply	Growth	Implementation	F2021	\$52
Transmission	Peace Region Electric Supply (PRES)	Growth	Implementation	F2022	\$285
Transmission	UBC Load Increase Stage 2	Growth	Implementation	F2022	\$55

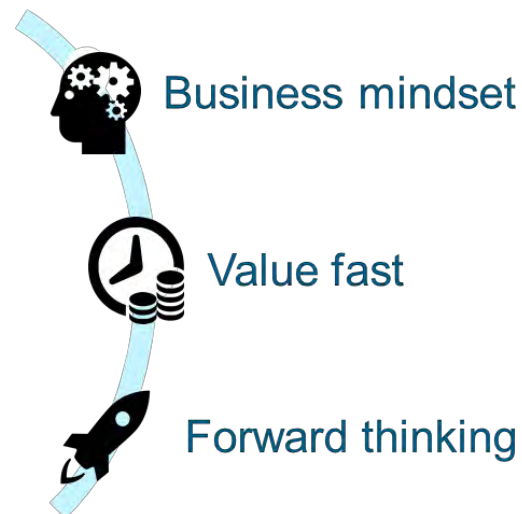
**BC Hydro Fiscal 2022
Revenue Requirements Application**

Appendix F

**Fiscal 2022 BC Hydro Technology Strategy
and 5-Year Plan**

BC Hydro Technology Strategy and 5-Year Plan

Supporting BC Hydro's Service Plan Objectives



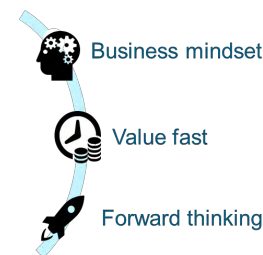
Prepared by the Technology Group

Updated September 2020



New in Fiscal Year 2021

BC Hydro's Technology Strategy and 5-Year Plan is refreshed annually to retain currency and adapt to change. The strategy is not expected to change although more emphasis may be put on certain drivers which can influence the plan. The refreshed plan reflects progress against objectives and changes in priorities. It is reviewed annually by the Executive Team and the Board.



Our strategy is to support BC Hydro in meeting its Service Plan objectives by optimizing our investments, delivering outcomes early and often, and leveraging future technology.

Over the past year we have made significant progress against the 5-Year Plan as well as in implementing the principles of the strategy. Our focus last year was on “making it easier to get work done” and using our principle of “delivering outcomes early and often” to rapidly make a difference for our front-line workers. We achieved this through mobile app development, deployment of robotic process automation and the introduction of rapid, iterative delivery methods where appropriate.

Two important areas of focus have emerged that require us to bring forward some elements of the plan. The first is the need to adapt to the COVID-19 pandemic and working from home. The second is the need to support ongoing compliance with Mandatory Reliability Standards (MRS).

This year we are focused short and long- term improvements to our systems in support of compliance with MRS as well as advancing the deployment of collaboration tools such as WebEx for virtual meetings, training and events and Microsoft Teams.

To put our strategy into action, we continue to prioritize our investment. Our first priority is to ensure sufficient investment in cybersecurity and compliance, our second is to sustain our existing assets and capabilities, and our third is to support new business functionality. The majority of our capital funding is invested in sustainment. One of the largest sustainment investments we will make over the next 5 years is to move our SAP core systems onto the next generation SAP platform and database.

The 2020 BC Hydro 5-year strategy identifies digitizing work management as an objective for achieving cost effectiveness. Pre-initiation work on enterprise asset and work management is underway to determine our approach to achieving this objective.

Introduction

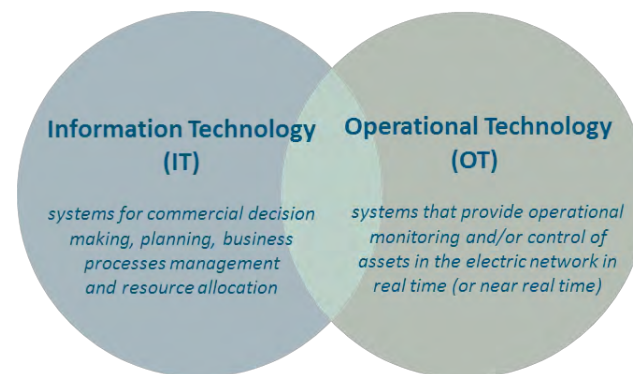
Technology plays a critical role in the operation of BC Hydro and is embedded in virtually everything we do; from enterprise business systems, to the monitoring and controlling of field assets, to mobile devices in the hands of workers. Global trends, business competition, and high consumer expectations are driving rapid advances in technology. In the utility industry, the application of digital technology is viewed as essential in meeting future business objectives.

For BC Hydro, investment in technology can help us achieve our service plan objectives to provide reliable and responsive service, maintain affordable rates, continue to support clean, renewable energy and focus on safety above all else.

In this document, “technology” refers to digital technologies encompassing *information technology* (IT) as well as *operational technology* (OT). Traditionally separate domains in the electric utility business, the digital technology environments of IT and OT are now converging as the trend continues towards automation of all aspects of the power systems and the use of grid system data for business decision-making. New capabilities using rapidly evolving digital technologies such as cloud computing, mobility, internet of things, and machine learning, are being implemented as utilities modernize towards a more intelligent grid – this is the digitization of the utility industry.



Opportunities to enable high-value business outcomes through digitization exist across the “Plan – Build – Operate – Support” functions of BC Hydro



Introduction

Our role

Technology is responsible for the planning, design, delivery, and operations of all information technology and a number of operational technology systems across the enterprise.

We provide technology leadership and oversight across BC Hydro. We actively collaborate with our organization to understand current and future needs. We are responsible for the enterprise technology architecture, and selection of appropriate technology solutions to deliver strong business outcomes.

Our work ensures our systems are reliable, secure, and able to meet the growing needs of BC Hydro.

Governance of our activities is provided by BC Hydro's Executive Team.



Introduction

About this document

This Technology Strategy and 5-Year Plan is the result of extensive collaboration across BC Hydro. Its primary goal is to provide guidance and direction for future technology investments to meet compliance and security objectives, sustain and modernize our existing operations, and enable new business capabilities.

Our strategy is to support BC Hydro in meeting its service plan objectives by optimizing our investments, delivering outcomes early and often, and leveraging future technology.

A clear strategy and plan is essential to inform the direction of future investments, but the approach looking forward must be flexible in order to adapt to, and exploit, the ever-changing technology landscape as well as to address new business opportunities as they arise. Given the rapid advancements in technology, and the continuing evolution of BC Hydro's business needs, the 5-Year Plan will be refreshed annually.

Our investment in technology is aligned with our capital plan over the next five years. The 5-Year plan describes the major investments we anticipate, however each will be supported by its own business case and initiated based on changing priorities, available funds and resources.

The purpose of this document is to:

- ✓ **Articulate BC Hydro's technology investment objectives**
- ✓ **Describe our strategy to meet these objectives**
- ✓ **Communicate the 5-Year Plan to guide investment and inform current and future regulatory submissions**

Context

- Our strategic objective
- Drivers for our strategy
- Digital value streams for electric utilities

Technology Strategy

Our strategic objective

This Technology Strategy and 5-Year Plan is designed to support BC Hydro in achieving its Service Plan Objectives:

- ✓ **Safety above all**
- ✓ **Set the standard for reliable and responsive service**
- ✓ **Help keep electricity bills affordable for our customers**
- ✓ **Help make renewable, clean power British Columbia's leading energy source**

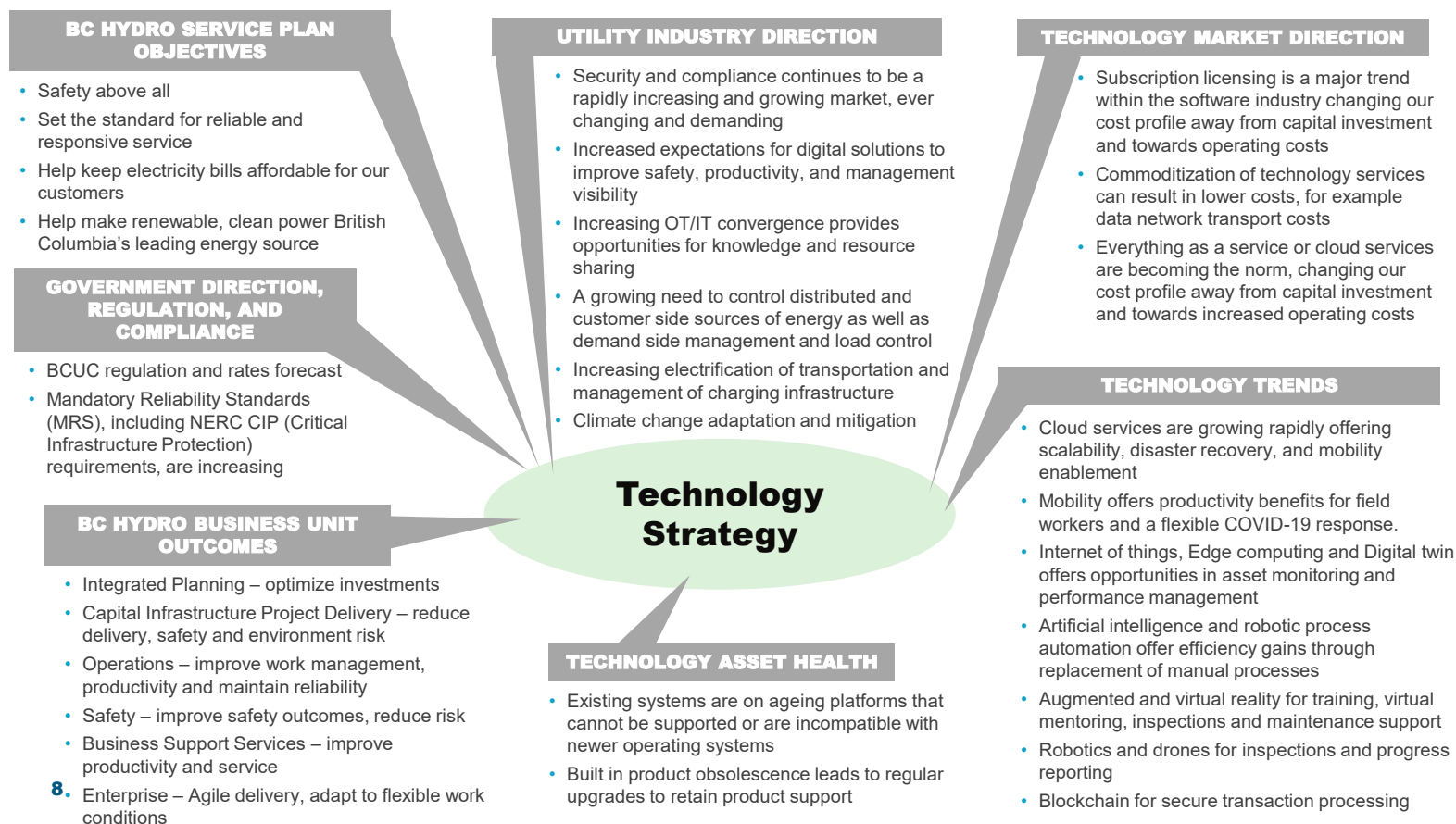
Implementation of technology solutions has the potential to advance each of these objectives, for example:

- By maintaining the health, stability and security of our digital systems we assist in ensuring the reliability and responsiveness of our service.
- Providing tools to streamline workflows, optimize work and asset management, and inform decision making all enable productivity improvements that lead to affordable rates.
- Mobile applications can provide location and job specific information to assist with improving safety outcomes for field workers.

Technology Strategy

Drivers for our strategy

BC Hydro is affected by numerous drivers having a direct impact on the strategy we employ to meet our objective. These drivers affect the type of investments we make, how we prioritize investments and adapt to future trends.



Technology strategy

Digital value streams for electric utilities

Digital technologies are used to enable new and improved capabilities and drive value across all functions of the utility.

PLANNING & DESIGN

High performance computing, cloud solutions, and advanced analytic and drafting tools enable more comprehensive and timely energy and system planning, load forecasting, resource management, engineering and design.

ASSET MANAGEMENT

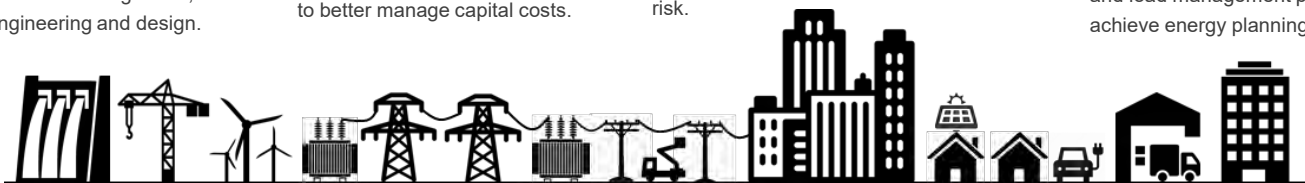
Real-time asset health information enables condition-based maintenance and just-in-time replacement to reduce asset sustainment costs. Asset health also provides for optimized investment planning to better manage capital costs.

MOBILE WORKFORCE

A fully mobile workforce seamlessly completes their field work. Job information is available, inspections are captured, drawings updated, and problems and progress automatically reported. Safety training and support is available on demand. Value is achieved through productivity, efficiency and reduced safety risk.

CUSTOMER ENGAGEMENT

Multi-channel technologies and relationship management tools improve quality and timeliness of customer interactions. Self-service reduces our costs and improves customer experience. Systems to support demand side management and load management programs help achieve energy planning targets.



WORK MANAGEMENT

Productivity, efficiency and risk reduction can be achieved through mobile applications, digital workflows to manage information and record keeping, use of drones to capture progress images, access to real-time data and business intelligence and analytics. Scheduling tools and optimization algorithms make managing work, during both normal and emergency situations, more efficient.

GRID INTELLIGENCE & CONTROL

Smart devices on the grid help optimize power delivery and resilience, and give operators and field service crews visibility into outages, faults, power quality issues, and the status of energized equipment. Digital systems manage distributed energy resources, automate connect and disconnect functions, power distribution and power quality.

SAFETY & SECURITY

Sensors, imaging and internet of things technologies provide visibility to facilities that are remote and/or unmanned. Monitoring and surveillance technologies improve identification and response to safety and security situations. Mobile field tools aid in worker and crew safety. Improved protection of digital information, systems and equipment reduces cyber security risk.

BUSINESS OPERATIONS

All business functions benefit from improvements to work processes, access to analytics, decision making, information management, and knowledge retention tools. Opportunities also exist to improve hiring, development and retention of valuable employees through specialized tools.

Our Strategy

- Principles
- Critical success factors

Technology Strategy

Our Strategy

We will adopt a business mindset, ensuring we work within our constraints to achieve the best outcomes for BC Hydro while maintaining the security and integrity of our information and systems at all times. We will adapt our solutions and processes to exploit short term opportunities and deliver outcomes early and often. We will develop technology roadmaps to ensure alignment on business solutions, leverage new technologies and prepare for technology obsolescence.

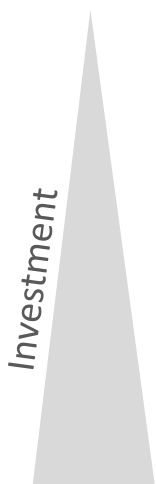


Technology Strategy

Principles – Business mindset



- ▶ **Justify and prioritize investments.** Investment proposals are selected into the portfolio based on relative value to the organization. Compliance, security, sustainment and risk mitigation solutions receive higher priority followed by those required to enhance business capability. Business cases must identify value and articulate specific benefits. Value (both cashable and non-cashable) from the investment must support the total cost of the investment.



Initiative / Investment	Description
Enhance our Capability	Discretionary activities that provide new or improved business capabilities
Manage our Risk and Sustain Productivity	Critical activities needed to ensure reliable and safe operations and to maintain the current level of productivity for our users
Compliance & Security	Mandatory activities needed to meet government/BCUC/NERC/WECC requirements

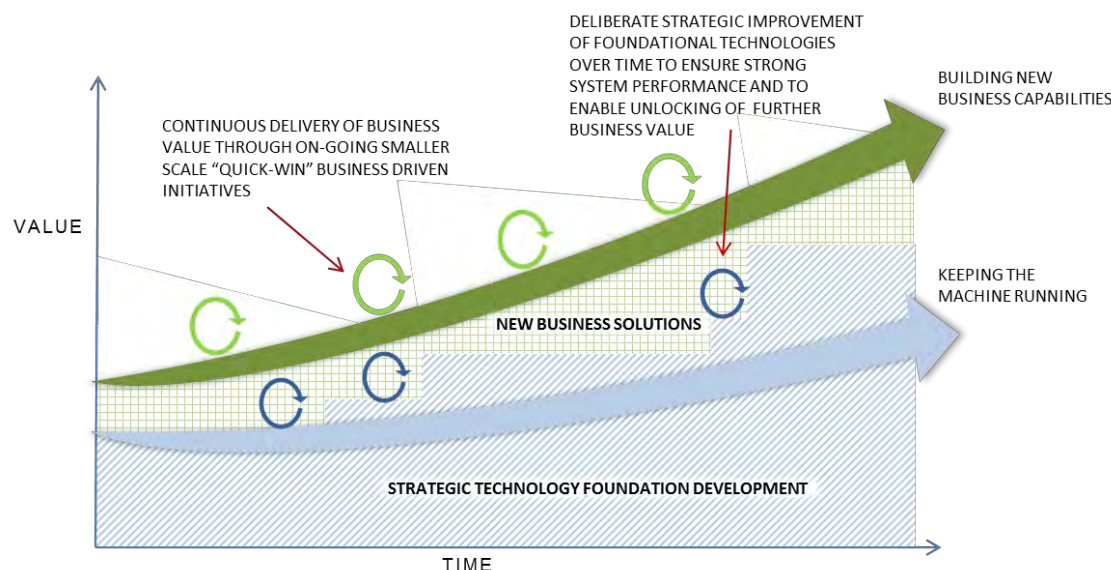
- ▶ **Work within our constraints.** Investment decisions are subject to the application of constraints due to funding, resource capacity, available skill sets, and ability of the organization to sustain and absorb change. Choices between investment options are decided through structured decision making.
- ▶ **Track the outcomes of investments.** Sponsors of technology-enabled initiatives are required to track benefits throughout implementation and into sustainment.

Technology Strategy

Principles – Value fast



- ▶ **Deliver value early and often.** Our approach is to exploit opportunities to deliver value early from interim solutions, even at a cost – provided the value exceeds the cost over the life of the interim solution. We will use “two-speed” or “agile” delivery methods, where appropriate, to expedite implementation of solutions.
- ▶ **Ensure architectural flexibility.** We will make investments that advance our delivery of value while still maintaining flexibility in our systems architecture. This allows for incremental and early value delivery, while implementing efficient and sustainable long-term foundation investments.



The diagram shows how we strive to deliver value early and often through incremental improvements (in green) while continuing to invest in our technology foundation for long term strategic business enablement (in blue)

Technology Strategy

Principles – Forward thinking



- **Build for the future.** Technology roadmaps describe how we can invest in our foundation and leverage new technologies to enable our strategic objectives. The roadmaps sequence initiatives, identify decision points, and provide unconstrained scheduling of milestones to enable business outcomes. Given the dynamic nature of technology and technology industry changes as well as changes to BC Hydro's environment, our roadmaps will be updated regularly. The following summaries describe current guidance for each foundation area however all initiative proposals require individual investment justification.



NETWORK CONNECTIVITY

Sustain existing wide area, field area and local area networks, as well as extend network bandwidth and coverage to our more remote sites. Continue to refresh our network equipment based on end-of-life cadence, meet current and future capacity requirements, and take advantage of software alternatives as they become available. Continue to invest in wireless networks for our facilities and vehicles to enable workforce mobility, asset management, and increased safety and security.



ENTERPRISE APPLICATIONS

Continue to upgrade our enterprise applications based on a cadence to maintain product support. As upgrades are scheduled, take advantage of opportunities to modernize current platforms as per industry direction to remain current and reduce risk of obsolescence.

Implement new customer contact centre systems to replace those that are not meeting requirements of availability and reliability, as well as modernizing the stack to extend and enhance current functionality for our customers.

For Enterprise Resource Planning (ERP), we have adopted a “Core ERP” approach in which SAP is our single system of record for enterprise data but the systems our users engage with may be “bolt-ons” or cloud service products. Complete SAP Supply Chain and initiate Enterprise Asset Management and Work Management allowing for improved work planning and scheduling as well as the decommissioning of Passport. Migrate SAP to the S4/HANA® platform to maintain currency and support. Use Robotic Process Automation (RPA) to replace manual, repetitive processes on a case-by-case basis.



CLOUD & DATA CENTRE

BC Hydro's approach to cloud is to adopt services on a case-by-case basis. Use cloud services as needed for compute power, specific business functionality, disaster response environment, collaboration and productivity. Continue to refresh our data centre servers, storage and other equipment based on end-of-life cadence. As equipment is replaced, leverage opportunities to consolidate racks as well as review cloud options. Leverage major product upgrades in line with the direction our product vendors as they move to cloud platforms.

Technology Strategy

Principles – Forward thinking



MOBILITY SERVICES

Extend and improve our mobile services and mobile workforce capabilities. Continue to refresh our user's mobile phones and devices based on recommended refresh cadence, break/fix and device management requirements. Complete replacement of our existing mobile application management platform to better support device management, performance and required functionality. To facilitate future development of field worker applications, implement a suite of container services, application program interfaces (APIs) and a mobile work management platform. Strive to extend our device management capability to a broader range of devices.



GIS

Our approach is to use the ESRI platform for new applications requiring GIS (Geographic Information System), upgrade the current version of Smallworld and defer future direction decisions on our Smallworld GIS applications until the next major product replacement or upgrade. This will likely be the replacement of our Distribution Analysis & Design (DAD) and Spatial Asset Management (SAM) tools. Continue to focus on integrating GIS with our CAD (Computer Aided Design) tools, mobile application and ERP capabilities in order to support designers, field workers, asset management and work management. Extend our use of GIS in application development to provide geographic location search to access information, provide operational and emergency situational awareness. Continue to upgrade our GIS platforms based on a cadence to maintain product support.



PERSONAL WORKSPACE

Continue to refresh personal computing devices based on recommended refresh cadence, productivity, break/fix and device management. Upgrade our desktop environment to Windows 10 to improve performance and functionality, implement Microsoft's Office 365 suite of tools to support improved collaboration and productivity, and migrate to Microsoft Exchange Online to optimize storage capacity, ensure product support and align with product vendor direction. Upgrade our information collaboration (SharePoint) platform and make SharePoint online available for collaboration in the future. We expect to maintain an "on premise" presence for security and business continuity.

Technology Strategy

Principles – Forward thinking



CYBER SECURITY

BC Hydro uses a risk-based approach to cyber security and information protection. New investments are made based on compliance requirements, emerging threats and retaining our risk posture. Comply with NERC (North American Electric Reliability Corporation) CIP (Critical Infrastructure Protection) standards. Respond to audit reports, assess risk and ensure security of grid and facilities. Sustain and maintain our information management systems, corporate monitoring tools, firewalls and other protection equipment based on end-of-life cadence, and risk mitigation. Leverage upgrades to modernize our architecture and optimize network segmentation through software as it becomes operationally mature. Apply information technology (IT) cybersecurity best practices to our operational technology (OT) environments and develop an information protection program to improve security of our systems of record, information sharing and records management platforms.



BUSINESS INTELLIGENCE & ANALYTICS

BC Hydro's direction is to adopt a self-service model for analytics in which users are given access to data and can use their own tools and analysts to meet their needs. In support of this approach, work to broaden access to our smart meter data, implement SAP on S4/HANA® for improved performance and easier data access, and implement a virtual data warehouse to improve ability to share both enterprise and business specific data across business functional areas. In addition, implement a telematics solution for fleet data analytics, fleet asset management and fleet operations, as well as a platform for asset investment planning and asset performance management to enable business outcomes such as enhanced condition based maintenance and predictive maintenance. Continue to leverage the Province of BC and TELUS Strategic Innovation Fund to explore implementation of an enterprise data collection platform (internet-of-things) to support business outcomes related to worker and public and dam safety.



ENERGY MANAGEMENT

BC Hydro's grid modernization work identified opportunities for improving operations, security, safety and visibility to the grid with many of these improvements involving the deployment of digital technologies. Our approach is to take advantage of these opportunities on a case-by-case basis depending on their ability to meet our strategic objectives, the priorities of our organization, the maturity of the technologies and business constraints. Continue to upgrade our Energy Management System and Outage Management System (PowerOn) to maintain product support, and work to extend the use of our smart meter data to support outage management objectives. Implement an integrated Advanced Distribution Management System to improve performance, meet business outcomes and align with product vendor direction.

Technology Strategy

Critical success factors

Delivery of the strategy demands that we address some non-technical factors that will be critical to success:

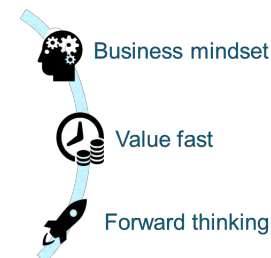
1. **Early engagement with our business leaders on strategic direction.** Technology must be recognized as necessary to achieving the goals of the organization. Technology leaders must be invited to work closely with business leaders during their planning to understand the strategic objectives and advise on opportunities for technology enablement.
2. **Streamline our delivery processes to be fit for purpose.** We have a robust IT delivery process (ITDSP) which has served us well in providing strong guidance and oversight of our project delivery function. This process does not scale adequately for our lower risk project activity nor provide the agility needed for user facing capability development. We are developing alternative delivery models (both variants to ITDSP as well as 2-speed or agile models) to meet the needs of modern technology deployment.
3. **Resource availability and reduction in capacity bottlenecks.** Project initiation decisions must consider not only capital investment availability. Equal emphasis is required for the availability of operating funds to support the non-capital project costs and on-going sustainment costs, and availability of resources to deliver and support pre-project and project delivery activities.
4. **Portfolio management prioritization and selection processes.** Capital investment prioritization and selection must be based on a common value framework for the organization and an integrated selection process that allows for trade-offs in non-sustainment investments. Investment decisions are subject to the application of constraints due to funding, resource capacity, available skill sets, sustainment capabilities, and ability of the organization to absorb change.
5. **Funding.** The current funding model based on capital investment for technology does not support future subscription and cloud services investments that typically require operating funds. A new funding model is required to ensure the success of future technology investment and operations.
6. **Governance, risk and compliance.** Continued central governance of systems architecture and project delivery is required to optimize resources and ensure compliance with security, privacy, delivery and architecture standards and policies.

5-Year Plan

- Developing the plan
- Future business outcomes
- Prioritization and constraints
- Investment summary
- Measuring our success
- Conclusion

New in Fiscal Year 2021

5-Year Plan



This year's 5-Year Plan has been refreshed to reflect the priorities and initiatives expected over the next five years under the current capital investment plan.

After the application of prioritization and constraints, our investments over the next five years are driven primarily by compliance, security and sustainment. With the completion of the Supply Chain Applications project, we are now planning for a future initiative to meet BC Hydro's work management objective. Pre-initiation work on Enterprise Asset and Work Management will provide us with the information we need on costs, benefits and approach to proceed with an investment designed to achieve our productivity and cost efficiency objectives.

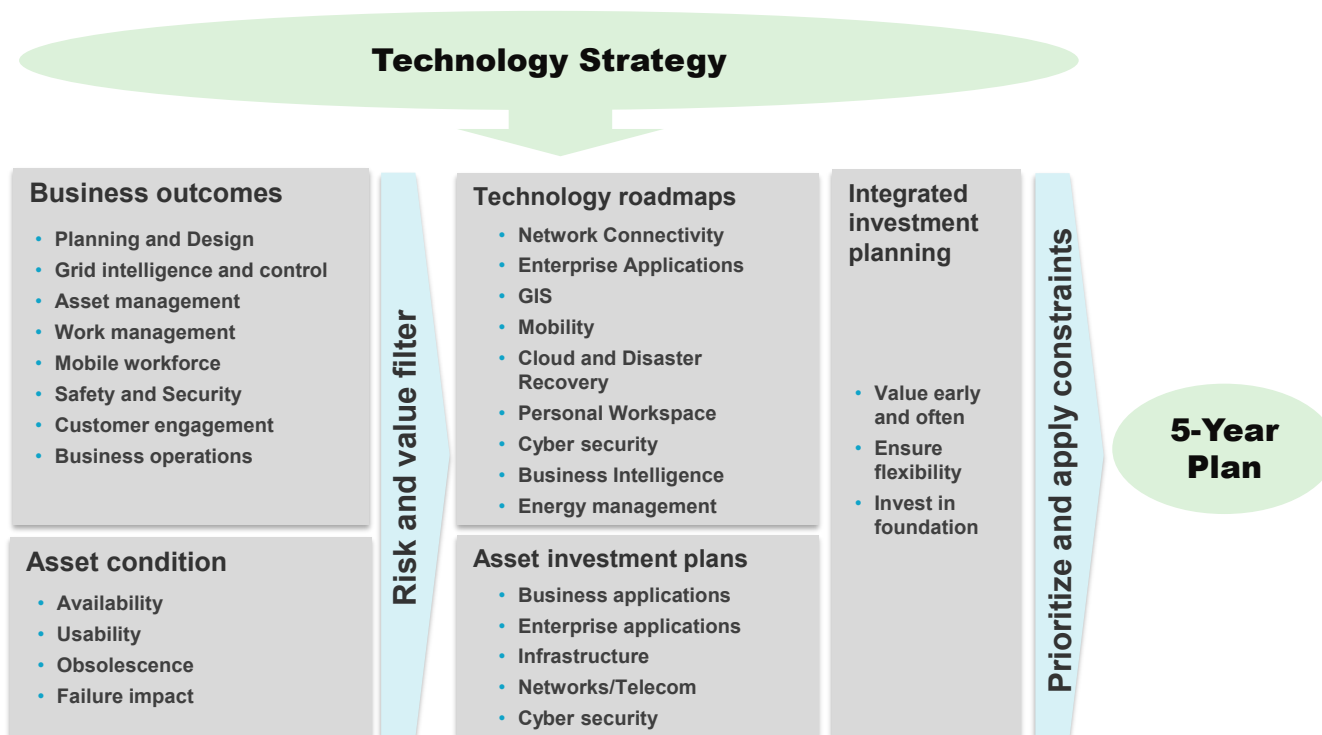
Pre-initiation work is also underway for migrating our core SAP system to S4/HANA. SAP HANA is SAP's in-memory database which provides technical capabilities to run transactions much faster and simpler access to the data. SAP S/4 HANA is a new version of SAP application that runs on SAP HANA database leveraging the power of in-memory computing. This version of SAP has a dramatically simplified data model, faster processing, advanced real-time data analytics capabilities and a modern user experience. It also provides options for robotic process automation, machine learning and artificial intelligence capabilities.

The compliance and security related investments in the capital plan include funding for any incremental investment that may be required as an outcome of our focus on identifying short and long-term improvements to our systems to support compliance with MRS.

5-Year Plan

Developing the plan

Fundamentally, the objective of the Technology group is to enable business outcomes and sustain the availability and security of our existing assets.



5-Year Plan

Developing the plan

In developing this Plan, the Technology group facilitated over twenty workshops with business group leaders to identify desired business outcomes for the next five to ten years. Over two hundred outcomes were articulated, with approximately half of those dependent on a technical solution. These outcomes were assessed for value based on executive and senior management's best judgement on their contribution to meeting our strategic objectives. This information is reviewed and confirmed annually and is used to inform our technology roadmap development and investment planning.

The condition, health and longevity of our assets are also assessed annually by our Technology team. Our Business Partner Services team also use their best judgement in how well the business and enterprise applications are meeting the needs of BC Hydro. This information, together with the impact of lost availability, is used to inform our technology asset investment plans.

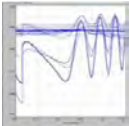
Integrated investment planning activities bring together the technology roadmap view, the asset investment view, and alignment with business expectations. The result is our aspiration for technology investment. Application of selection and prioritization criteria, as well as funding and resource constraints, leads to the development of the five year plan.

This 5-Year Plan shows the investments currently anticipated based on BC Hydro's capital plan for the next five years. With the application of prioritization and constraints, our investments over the next five years will be driven primarily by compliance, security and sustainment. This year, we begin planning for opportunities to improve business capabilities in priority areas. These plans allow us to initiate investment as resources become available. Priority investments are those that provide opportunities for making it easier to get work done and achieving operational efficiencies.

5-Year Plan

Future business outcomes

Our Technology team reviewed and aggregated the business outcomes for commonalities and determined the underlying technology investment needed. This is a summary of the aggregated business outcomes.

VALUE STREAMS								
	 PLANNING & DESIGN	 GRID INTELLIGENCE & CONTROL	 ASSET MANAGEMENT	 WORK MANAGEMENT	 MOBILE WORKFORCE	 SAFETY AND SECURITY	 CUSTOMER ENGAGEMENT	 BUSINESS OPERATIONS
BUSINESS OUTCOMES	- Enhanced load forecasting and energy planning - Enhanced engineering design	- Distribution grid management - Demand response management - Digital substations - Distributed energy resource management - Resilient telecommunications networks	- Integrated and optimized investment planning - Asset performance management - Asset intelligence for operations - End-to-end asset management	- Operations work planning and scheduling - Optimized planned outage management - Real-time monitoring and management of work	- Ability to complete job on site - Safety practices integrated into work process on site - Work site awareness - Real-time visibility to grid status on site - Ability to collect quality information from the field	- Resilient and secure IT and OT systems - Real-time situation awareness during emergencies - Physical grid security - Automated facility security - Enhanced dam safety systems	- Customer inclusion in conservation and electrification programs - Improved outage and restoration information - Customer work booking - Optimized customer service interactions	- Optimized supply chain function - Optimized back office processes - Enhanced data access and business intelligence - Improved information, records management, search - Improved employee experience, productivity and collaboration - Workforce planning and development

5-Year Plan

Prioritization and Constraints

There are many opportunities for utilizing technology to unlock value in BC Hydro but it is not possible to achieve all outcomes all at once. Therefore, it is necessary to **prioritize** the outcomes and focus on those which we consider most important to the organization. In general, mandatory initiatives needed to address *compliance and security* are the highest priority and critical initiatives that address *risk management and sustainment of productivity* are next.



Initiative / Investment	Description
Enhance our Capability	Discretionary activities that provide new or improved business capabilities
Manage our Risk and Sustain Productivity	Critical activities needed to ensure reliable and safe operations and to maintain the current level of productivity for our users
Compliance & Security	Mandatory activities needed to meet government/BCUC/NERC/WECC requirements

Initiatives that *enhance our capability* are considered discretionary and are third in priority ranking. It should be noted, however, that these initiatives may provide significant benefits and help us in achieving our strategic objectives.

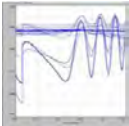
Once prioritized, it is necessary to apply our **constraints** in order to develop a plan that can be delivered with confidence. We apply a number of critical constraints including,

- The Technology team capacity
- Capital and operating funding
- Business capacity for change
- Availability of BC Hydro and contractor support resources
- Technical dependencies
- Technology maturity

5-Year Plan

Investment summary

Under the current constraints, work will continue to complete projects underway and a limited number of new business value initiatives will be undertaken. The bolded outcomes are those that are wholly or partially addressed by major planned initiatives.

VALUE STREAMS								
	 PLANNING & DESIGN	 GRID INTELLIGENCE & CONTROL	 ASSET MANAGEMENT	 WORK MANAGEMENT	 MOBILE WORKFORCE	 SAFETY AND SECURITY	 CUSTOMER ENGAGEMENT	 BUSINESS OPERATIONS
BUSINESS OUTCOMES								
	- Enhanced load forecasting and energy planning - Enhanced engineering design	- Distribution grid management - Demand response management - Digital substations - Distributed energy resource management - Resilient telecommunications networks	- Integrated and optimized investment planning - Asset performance management - Asset intelligence for operations - IT and OT system asset management	- Operations work planning and scheduling - Optimized planned outage management - Real-time monitoring and management of work	- Ability to complete job on site - Safety practices integrated into work process on site - Work site awareness - Real-time visibility to grid status on site - Ability to collect quality information from the field	- IT and OT system security and resilience - Real-time situation awareness during emergencies - Physical grid security - Automated facility security - Enhanced dam safety systems	- Customer inclusion in conservation and electrification programs - Improved outage and restoration information - Customer work booking - Optimized customer service interactions	- Optimized supply chain function - Optimized back office processes - Enhanced data access and business intelligence - Improved information, records management, search - Improved employee experience, productivity and collaboration - Workforce planning and development

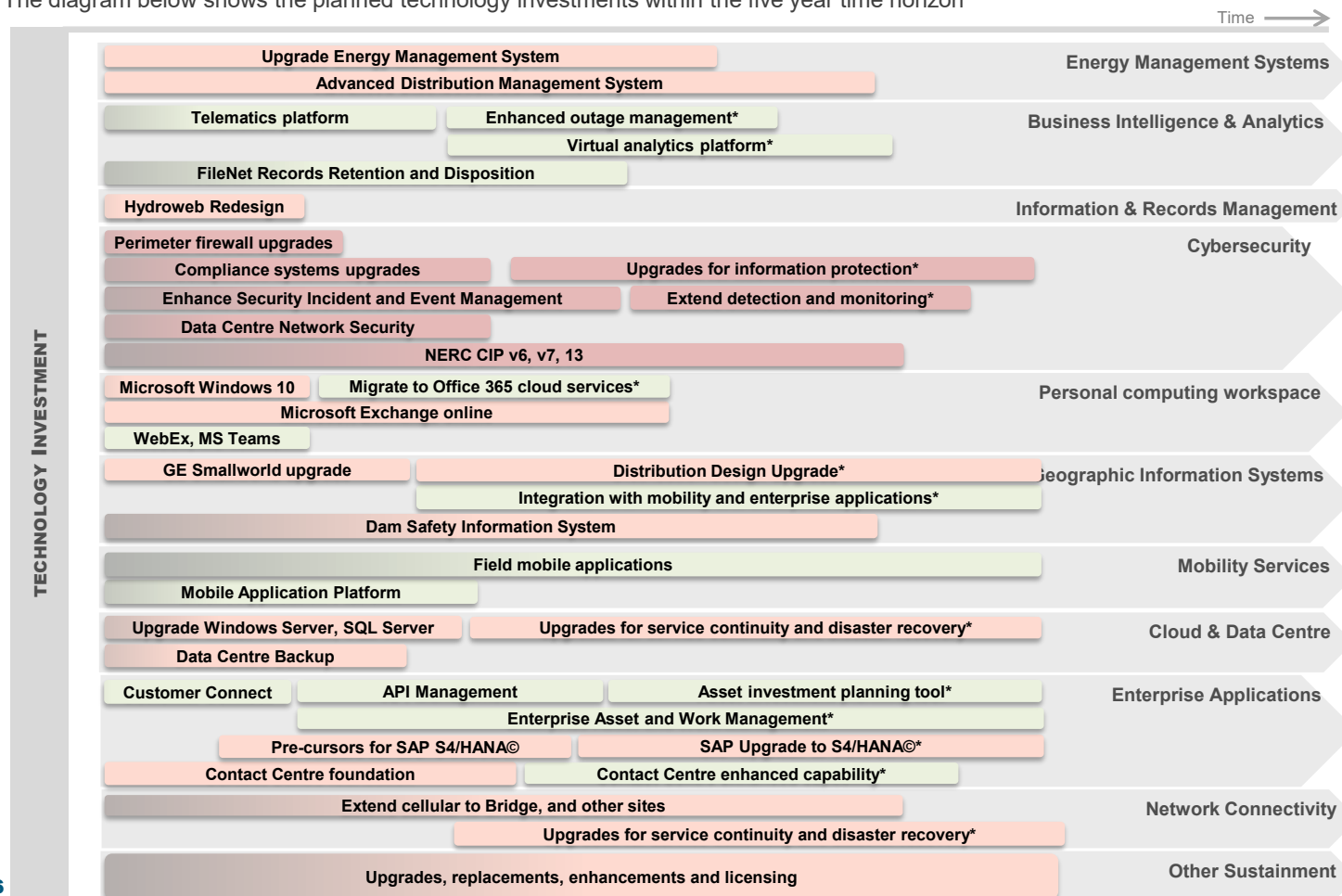
5-Year Plan

	Investment Initiatives	Business outcome
Security and Compliance	NERC CIP v6, v7, NERC CIP-013 Compliance System Upgrades	IT and OT system security and resilience Physical grid security
	Firewall Upgrades Enhance Security Incident and Event Management (SIEM) Extend Detection and Monitoring	IT and OT system security and resilience Physical grid security
Risk and Productivity Sustainment	Upgrades: Energy Management System (EMS), Windows 10, Exchange Online, Windows Server and SQL Server, Enterprise Mobile Application Management, GE Smallworld GIS, Contact Centre Foundation, PowerOn 4.3, Energy Analytics System GreenPlum Hardware Upgrade, SAP Technical Upgrades, API Management, WISKI Upgrade (water) Replacement: Surrey Campus Network, CIDC Network, FVO/SIO Network, Regional Site Infrastructure, Corporate Telephony, Data Centre Infrastructure (servers, storage, network devices), Personal Devices (PCs, Phones, Tablets), SAP Customer Management, Learning System, Advanced Distribution Management System Studies: Distribution Design Replacement and Passport Decommission Study, SAP S4/HANA Migration Study Product licensing and enhancements to ensure vendor support	IT and OT system security and resilience IT and OT systems asset management
	Extended Cellular to Dam Facilities Dam Safety Information System	Enhance dam safety systems
Enhance Business Capability	Customer Connect Web Enablement Enable Voluntary Time-based Rates	Optimized customer services interactions Customer inclusion in conservation and electrification programs
	WebEx, Microsoft Teams Enterprise Hydro Web (Intranet) Redesign FileNet Records Retention and Disposition	Improved employee experience, productivity and collaboration Improved information, records management, search
	Field mobile applications Mobility Application Platform	Ability to complete job on site Ability to collect quality information from the field Safety practices integrated into work processes on site
	Studies: Enterprise Asset and Work Management Study, Lines Asset Hierarchy Study, Contractor Lifecycle Study	Operations planning and work scheduling
	Telematics Platform	Asset intelligence for operations

5-Year Investment Plan

Investment Summary

The diagram below shows the planned technology investments within the five year time horizon



*Those initiatives with an asterisk are not included in the F21 current capital portfolio.

5-Year Plan

Measuring our success

The Technology group has a variety of ways to track and measure the success of our capital investments. These range from the immediate and quantifiable, such as operational and delivery metrics, to the completely qualitative business satisfaction survey. We recently introduced a benefits tracking process for business capability driven initiatives. In this process both quantitative and qualitative assessments are made over a period of time following deployment of a solution.

- **Operational Metrics** – Technology uses a number of metrics to evaluate and track the performance of our systems, services, and vendors.
- **Delivery Metrics** – Technology uses a number of metrics to assess and track the performance of our delivery which include measures on cost, schedule, and quality.
- **Business satisfaction** – Technology conducts an annual satisfaction survey to solicit feedback from across the business of the level of satisfaction with Technology delivery and services.
- **Project Benefits** – Benefits from initiatives undertaken as part of implementing technology solutions will be tracked to assess how well they deliver on the expectations set out in their respective business cases.

Technology Strategy and 5-Year Plan

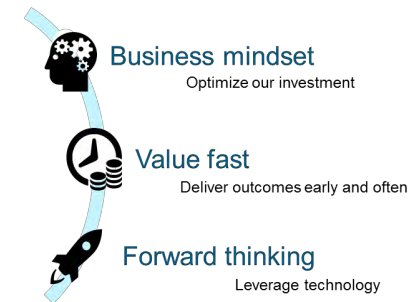
Conclusion

Our strategy describes BC Hydro's landscape and the drivers that influence our future business and technology decisions; our overall objective is to help BC Hydro achieve its service plan goals through the use of technology. We identify eight value streams across BC Hydro through which technology can unlock significant benefits. Our approach is to operate with a *business mindset*, to deliver *value fast*, and to be *forward thinking* in all we do.

BC Hydro's 5-Year Technology Investment Plan identifies expected business outcomes from across planning, delivery, operations and business support functions. The outcomes are assessed based on their ability to help achieve our service plan objectives. Following prioritization and the application of constraints, the Plan describes the outcomes we expect to achieve in the next five years and the corresponding investments in technology.

We must also sustain and maintain our existing systems. Investments for sustainment include refreshes for infrastructure, personal devices, network, telephony and cyber security assets, as well as upgrades and replacement of business and enterprise applications.

The plan reflects corporate planning activities and uses input from BC Hydro's executive and senior managers as well as the Technology subject matter experts. BC Hydro uses an annual planning cycle to maintain currency of plans and adapt to changes. We expect to update this plan annually.





BC Hydro Fiscal 2022
Revenue Requirements Application

Appendix G

Asset Health - Generation

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1 Introduction

Equipment health is assessed for Generation, Transmission and Distribution assets. The information is used for the life-cycle management of assets, including supporting the need for capital investments. The methodologies used provide a systematic, objective, repeatable, and transparent assessment of asset health. BC Hydro uses two asset health-based methodologies to assess the health of the generation, transmission, substation, and distribution assets. These ratings are similar, and, for reporting purposes, results are presented using a common Asset Health Rating (**AHR**) scale of Good, Fair, Poor and Very Poor.

BC Hydro uses a methodology called Equipment Health Rating to evaluate the health of Generation assets.

2 Generation Equipment Health Ratings

BC Hydro periodically evaluates the condition of its major generation assets (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data. Health assessments are based primarily on asset condition, but also consider safety and environmental issues, reliability, design deficiencies, asset age and industry expected life and availability of spare parts and technical expertise.

Each health assessment results in a rating of Good, Fair, Poor, or Very Poor:

- **Good:** The asset is in as new condition, with no noticeable deterioration or defects;
- **Fair:** There is some normal deterioration of the asset with one or more minor defects; function is not affected;

-
- 1 • **Poor:** There is serious deterioration of the asset or serious defects in at least
2 some portions of the asset; function is affected; and
- 3 • **Very Poor:** There is extensive deterioration of the asset and the asset no
4 longer functions as designed.

5 Equipment Health Index ratings for Generation assets as of March 2020 are
6 provided below.

Key Generating Stations						
AHR Letter Grades as of March 31 2020						
	Turbines	Governors	Generators	Exciters	Circuit Breakers	Transformers
G.M. Shrum						
GMS1						
GMS2						
GMS3						
GMS4						
GMS5						
GMS6						
GMS7						
GMS8						
GMS9						
GMS10						
Peace Canyon						
PCN1						
PCN2						
PCN3						
PCN4						
Bridge River						
BR11						
BR12						
BR13						
BR14						
BR25						
BR26						
BR27						
BR28						
Kootenay Canal						
KCL1					N/A	
KCL2					N/A	
KCL3					N/A	
KCL4					N/A	
Mica						
MCA1						
MCA2						
MCA3						
MCA4						
MCA5						
MCA6						
Revelstoke						
REV1						
REV2						
REV3						
REV4						
REV5						
Seven Mile						
SEV1						
SEV2						
SEV3						
SEV4						

Good
Fair
Poor
Very Poor
Not Available

Strategic Generating Stations

AHR Letter Grades as of March 31 2020

	Turbines	Governors	Generators	Exciters	Circuit Breakers	Transformers
Ash River ASH1						
John Hart JHT1						
JHT2						
JHT3						
JHT4						
JHT5						
JHT6						
Jordan River JOR1						
Ladore LDR1						
LDR2						
Puntledge PUN1						
Strathcona SCA1						
SCA2						
Alouette Lake ALU1*						
Cheakamus River CMS1						
CMS2						
Clowholm River COM1						
Lake Bunten 1 LB11						
Ruskin RSN1						
RSN2						
RSN3						
Stave Falls SFN1						
SFN2						
Wahleach Creek WAH1						
La Joie LAJ1						
Seton SON1						

* Unit currently out-of-service

Available Generating Stations

AHR Letter Grades as of March 31 2020

	Turbines	Governors	Generators	Exciters	Circuit Breakers	Transformers
Aberfeldie						
ABN1						
ABN2						
ABN3						
Elk River						
ELK1*						
ELK2*						
Falls River						
FLS1						
FLS2						
Shuswap						
SHU1*						
SHU2						
Spillimacheen						
SPN1*						
SPN2*						
SPN3*						
Walter Hardman						
WHN1						
WHN2						
Whatshan						
WGS1						

* Unit currently out-of-service

	Good		Fair		Poor		Very Poor

Fiscal 2022

Revenue Requirements Application

Appendix H

Asset Health – Transmission and Distribution

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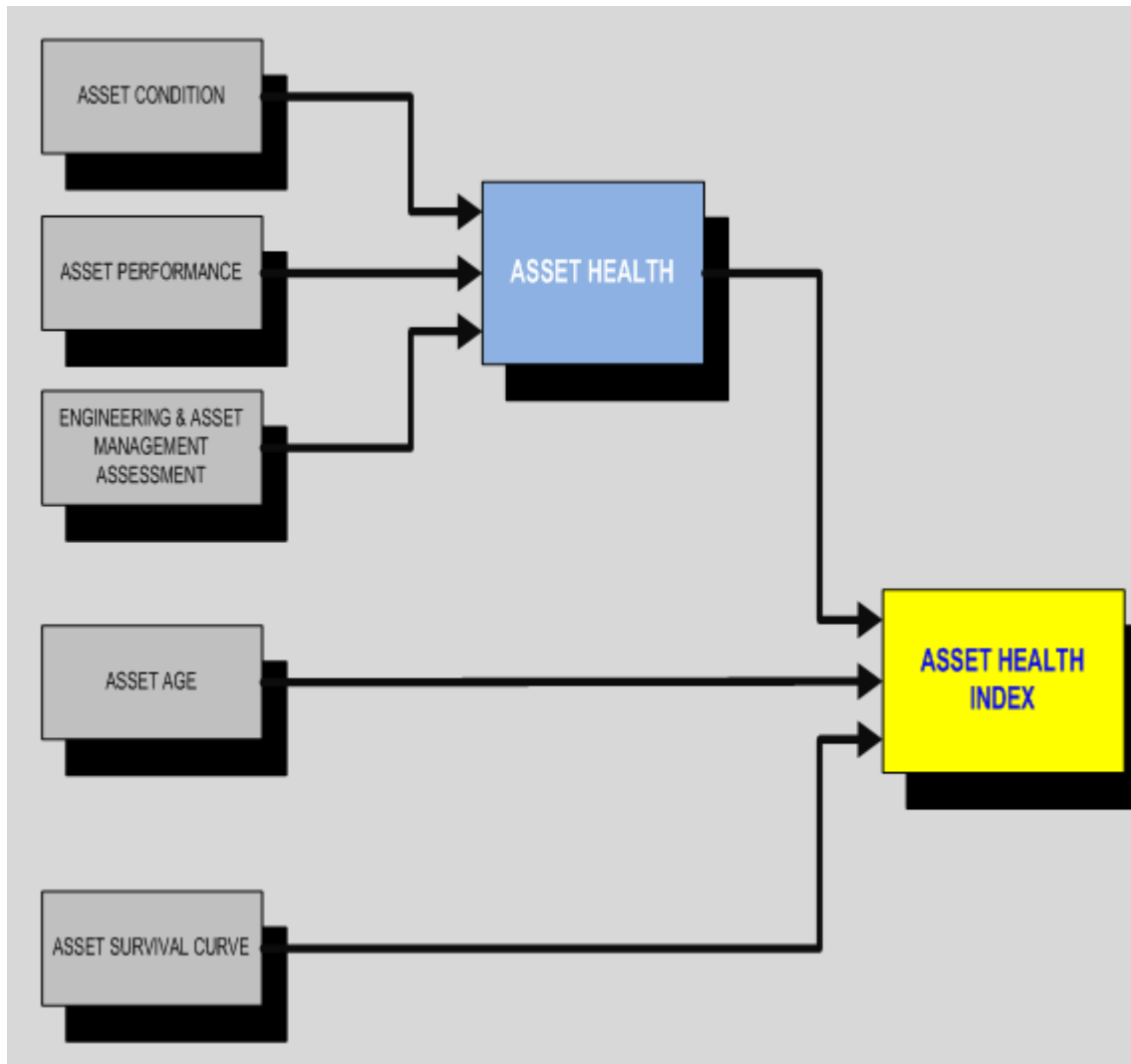
1 Introduction

Equipment health is assessed for Generation, Transmission and Distribution assets. The information is used for the life cycle management of assets, including supporting the need for capital investments. The methodologies used provide a systematic, objective, repeatable, and transparent assessment of asset health. BC Hydro uses two asset health-based methodologies to assess the health of the generation, transmission, substation, and distribution assets. These ratings are similar, and for reporting purposes, results are presented using a common Asset Health Rating (AHR) scale of Good, Fair, Poor and Very Poor.

BC Hydro uses a methodology called Asset Health Index to evaluate the health of Transmission and Distribution assets.

2 Transmission and Distribution Asset Health

The Asset Health Index is derived from maintenance and asset management data. The methodology is illustrated below.

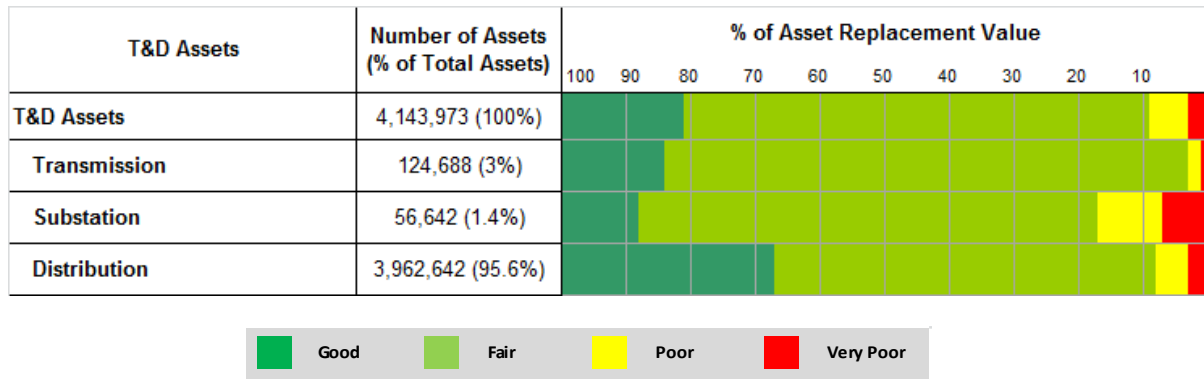


- 1 Asset Health Ratings and possible investment needs are:

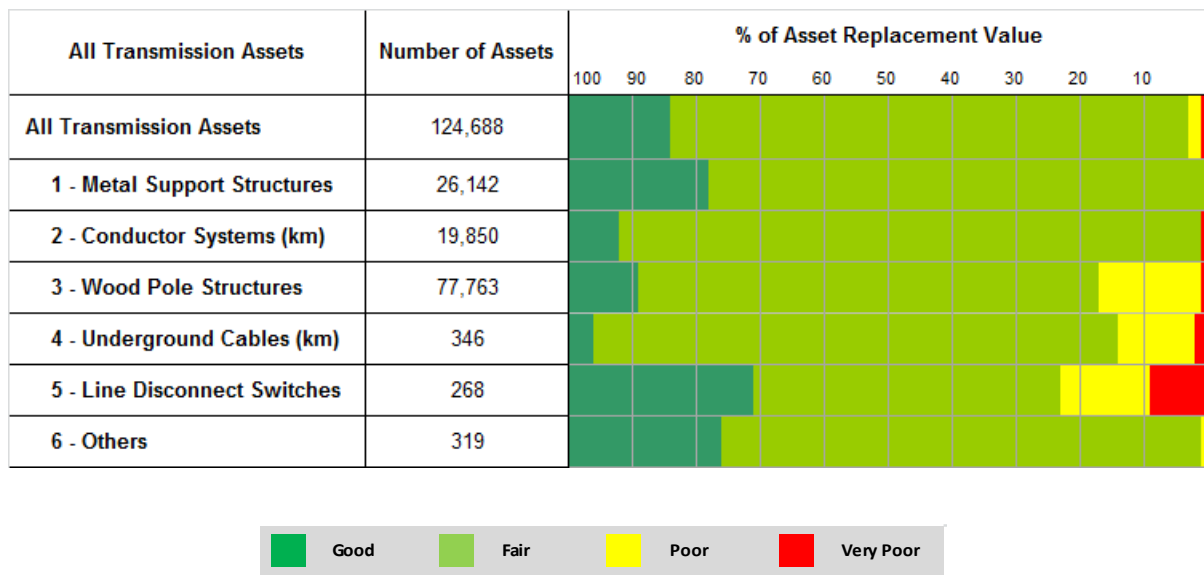
AHR	Description
Good	Some aging or minor deterioration of a limited number of components
Fair	Widespread significant deterioration or serious deterioration of specific components
Poor	Widespread serious deterioration
Very Poor	Extensive serious deterioration

- 1 Asset Health Rating can be grouped and analysed by asset class and/or criticality.
2 Below are Asset Health Rating charts for Transmission and Distribution asset
3 classes as of April 2020:

4 **Table H-1 Asset Health Rating Summary**



5 **Table H-2 Asset Health Rating for Transmission**
6 **Line Assets**



1
2

Table H-3 Asset Health Rating for Substation Assets

All Substation Assets	Number of Assets	% of Asset Replacement Value									
		100	90	80	70	60	50	40	30	20	10
All Substation Assets	56,642	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
1 - Transformers	1,437	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
2 - Gas Insulated Switchgear	540	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
3 - Circuit Breakers	3,978	Good	Good	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
4 - Reactors	1,971	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
5 - Protection & Control Relay Systems	14,381	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
6 - Shunt Capacitors	432	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
7 - Disconnect Switches	14,297	Good	Good	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
8 - Instrument Transformers	8,522	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
9 - Series Capacitors	14	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
10 - HVDC Pole 2 (To be Obsolete)	1	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good
11 - Surge Arrestors	6,454	Good	Good	Good	Good	Fair	Fair	Fair	Fair	Poor	Very Poor
12 - Synchronous Condensers	4	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
13 - Static VAR Compensator	5	Good	Good	Good	Good	Fair	Fair	Fair	Fair	Poor	Very Poor
14 - Station Insulators	435	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
15 - Standby Generators and Fuel Systems	76	Good	Good	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
16 - Mobile Transformers & Mobile Unit Substations	9	Good	Good	Good	Good	Fair	Fair	Fair	Fair	Poor	Very Poor
17 - Batteries	339	Good	Good	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
18 - Fire Protection Systems	162	Good	Good	Good	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
19 - Voltage Regulators	360	Good	Good	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor
20 - Others	3,225	Good	Fair	Fair	Fair	Fair	Fair	Fair	Fair	Poor	Very Poor



1
2

Table H-4 Asset Health Rating for Distribution Assets

All Distribution Assets	Number of Assets	% of Asset Replacement Value									
		100	90	80	70	60	50	40	30	20	10
All Distribution Assets	3,962,643										
1 - Distribution Poles	893,184										
2 - Underground Transformers	69,405										
3 - Overhead Transformers	284,727										
4 - Overhead Primary Conductors (km)	47,896										
5 - Underground Primary Cables (km)	11,069										
6 - Revenue Meters	2,097,523										
7 - Cutouts	412,218										
8 - Overhead Switches	12,860										
9 - Overhead Reclosers	1,523										
10 - Street Lights	92,077										
11 - Voltage Regulators	602										
12 - Capacitors	291										
13 - Others	39,268										



**BC Hydro Fiscal 2022
Revenue Requirements Application**

Appendix I

Fiscal 2022 Capital Expenditures > \$5 million

PUBLIC

Appendix I - F2022 RRA - Generation
Projects greater than \$5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F22) as at April 1, 2019 (1), (2)
\$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	F2020-F2021 RRA Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	F2020-F2021 RRA Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Generation																										
		Hydroelectric																								
		Growth																								
1	G000594	Revelstoke Install Unit 6	Growth	Definition (Note A)	F2030	TBD	F2014	-		458 - 255	-	-	-	-	2.4	4.6	5.0	Y	Exempt per section 7 of Clean Energy Act	Page 1	Revelstoke Facility Asset Plan	Page 35	N	For Prioritization	Note B	
		Dam Safety																								
2	G000246	Revelstoke Improve Left Bank Slope Stability	Sustaining	Definition	F2021	F2020	F2019			16.2 - 9.4		-	-	10.4	1.9	7.7	0.6	N			Revelstoke Facility Asset Plan	Page 35	N	For Prioritization	11	
3	G000001	Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	-	0.2	0.6	N			Alouette Facility Asset Plan	Page 3	N	For Prioritization	10	
4	G000011	Alouette Improve Headworks & Surge Tower Seismic Stability	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	1.2	3.4	8.2	N		Page 7	Alouette Facility Asset Plan	Page 3	N	For Prioritization	11	
5	G003467	Bridge River 1 - Improve Slope Drainage	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	0.0	0.2	13.2	N			Bridge River Facility Asset Plan	Page 7	N	For Prioritization	9.5	
6	G003852	Bridge River 1 - Mitigate Surge Spill Hazard	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	5.9	0.5	2.5	2.9	N			Bridge River Facility Asset Plan	Page 7	N	For Prioritization	10	
7	G003554	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	0.4	0.4	1.2	N		Page 19	G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	11	
8	G003555	W.A.C. Bennett Dam Seal Low Level Outlets	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	1.0	1.3	3.2	N		Page 21	G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	11	
9	G000585	John Hart Dam Seismic Upgrade	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	11.0	13.0	10.1	N	s44.2	Page 13	Campbell River Study	Page 1	N	For Prioritization	11	
10	G000459	La Joie - Dam Improvements	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	-	3.3	2.9	N	Potential s44.2				N	For Prioritization	10	
11	G000668	Ladore Spillway Seismic Upgrade	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	1.4	2.2	1.8	N	Potential s44.2	Page 15	Campbell River Study	Page 1	N	For Prioritization	10	
12	G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	-	0.0	1.8	N	Potential s44.2	Page 25	Mica Facility Asset Plan	Page 26	N	For Prioritization	11	
13	G003127	Peace Canyon Install Piezometers and Drains in Concrete Dam	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	0.2	1.0	1.9	N			Peace Canyon Facility Asset Plan	Page 29	N	For Prioritization	9.5	
14	G000657	Comox - Puntledge Flow Control Improvements	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	0.0	1.3	5.9	N		Page 9	Puntledge Facility Asset Plan	Page 33	N	For Prioritization	12	
15	G003129	Revelstoke Replace Downie Slide Instrumentation	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	0.9	7.7	9.7	N			Revelstoke Facility Asset Plan	Page 35	N	For Prioritization	9	
16	G000525	Strathcona Upgrade Discharge	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	4.2	5.2	9.8	N	Potential s44.2	Page 17	Campbell River Study	Page 1	N	For Prioritization	11	
17	G000467	Terzaghi - Spillway Chute Access Improvement	Sustaining	Identification	TBD	TBD	TBD			TBD		-	-	-	-	0.6	6.4	N			Bridge River Facility Asset Plan	Page 7	N	For Prioritization	11	
18	G004132	W.A.C. Bennett Dam - Spillway Concrete Upgrades	Sustaining	Identification	TBD	TBD	TBD			TBD		-	5.2	0.1	0.2	5.0	0.1	N			G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	10.5	
19	G004209	W.A.C. Bennett Dam - Stoplogs Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD		-	-	-	-	0.5	5.0	N			G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	10	
20	G000556	Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD		-	-	-	-	0.3	1.9	N		Page 23	Hugh Keenleyside Facility Asset Plan	Page 15	N	For Prioritization	10.5	
21	G003653	Various Sites - Reservoir Booms Replacement - F2020	Sustaining	Future	TBD	TBD	TBD			TBD		-	2.1	6.6	0.0	1.9	8.7	N					Y	For Prioritization	9.5	
22	G004172	Various Sites - Spillway Gate Standby Power Improvements	Sustaining	Future	TBD	TBD	TBD			TBD		-	-	-	-	-	1.1	N					N	For Prioritization	11	
		Sustaining - Other																								
23	G000057	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	Sustaining	Implementation	F2023	F2019	F2018	23.5	F2023	N/A - In Implementation	23.5	-	18.3	-	7.6	7.2	0.4	N		Page 38	Cheakamus Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 10 and 31	N	For Prioritization	10.5	
24	G000571	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	Sustaining	Implementation	F2023	F2015	F2014	10.7	F2020	N/A - In Implementation	12.4	-	-	9.9	1.2	2.1	1.1	N			Cheakamus Facility Asset Plan	Page 10	N	Committed		
25	G000127	G.M. Shrum G1 to 10 Control System Upgrade	Sustaining	Implementation	F2023	F2018	F2013	75.0	F2023	N/A - In Implementation	75.0	5.0	15.0	7.0	13.3	13.1	3.9	N		Page 32	G.M. Shrum Facility Asset Plan	Page 13	N	Committed		
26	G000172	Mica Modernize Controls	Sustaining	Implementation	F2024	F2019	F2018	47.8	F2024	N/A - In Implementation	47.8	6.7	8.8	8.8	13.0	8.7	10.0	N		Page 43	Mica Facility Asset Plan	Page 26	N	Committed		
27	G003207	Mica Replace Units 1 to 4 Generator Transformers	Sustaining	Implementation	F2023	F2018	F2017	82.1	F2023	N/A - In Implementation	82.1	11.6	16.5	16.5	22.7	13.4	14.6	Y		Page 34	Mica Facility Asset Plan	Page 26	N	Committed		
28	G003456	Mica Upgrade 600V Circuit Breakers	Sustaining	Implementation	F2021	F2019	F2016	18.9	F2021	N/A - In Implementation	18.9	-	18.0	4.3	3.1	11.6	4.3	N			Mica Facility Asset Plan	Page 26	N	Committed		
29	G000241	Puntledge Recoat Interior and Exterior of Steel Penstock	Sustaining	Implementation	F2022	F2019	F2017	35.7	F2022	N/A - In Implementation	35.7	-	12.0	12.7	7.9	7.0	6.8	N		Page 44	Generation Asset Management Strategy - Penstock Recoating	Pages 31 and 33	N	Committed		
30	G000792	Seven Mile Replace Unit 1-4 Exciter Transformers	Sustaining	Implementation	F2022	F2019	F2018	14.9	F2022	N/A - In Implementation	14.9	-	8.4	2.5	1.8	3.8	2.5	N			Seven Mile Facility Asset Plan	Page 39	N	Committed		
31	G000342	Wahleach Recoat Penstock (Interior and Exterior)	Sustaining	Implementation	F2023	F2019	F2018	21.8	F2022	N/A - In Implementation	21.8	-	-	-	5.5	5.3	2.7	N		Page 46	Wahleach Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 31 and 44	N	Committed		
32	G000493	Bridge River 2 Upgrade Units 7 and 8	Sustaining	Definition	F2022	F2020	F2019	-		87 - 72	-	-	-	77.0	19.4	41.1	21.3	N		Page 52	Bridge River Facility Asset Plan	Page 7	N	For Prioritization	10.5	
33	G000114	G.M. Shrum Upgrade HVAC System	Sustaining	Definition	F2024	F2020	F2016	-		20 - 11	-	-	-	-	0.6	1.0	0.7	N		Page 40	G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	10	
34	G003515	Various - Water License Renewal	Sustaining	Definition	F2022	F2020	F2017	-		11.4 - 8.5	-	-	-	-	1.5	1.0	3.1	N					N	Mandatory		
35	G003035	Hugh Keenleyside Recoat Navlock Gates	Sustaining	Definition	F2023	F2020	F2019	-		20 - 11	-	-	-	-	0.3	4.2	4.4	N			Hugh Keenleyside Facility Asset Plan	Page 15	N	For Prioritization	10	
36	G000158	Jordan - Upgrade Governor & PRV Controls	Sustaining	Definition	F2023	F2021	F2019	-		20 - 11	-	-	-	-	0.6	2.1	2.5	N			Jordan River Facility Asset Plan	Page 18	N	For Prioritization	10	
37	G000640	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	Sustaining	Definition	F2023	F2021	F2016	-		52 - 19	-	-	-	22.6	2.6	2.7	14.9	N		Page 41	Coquitlam-Buntzen System Facility Asset Plan	Page 24	N	For Prioritization	10	
38	G000801	Mica Upgrade HVAC System	Sustaining	Definition	F2023	F2020	F2018	-		40 - 32	-	-	-	-	0.7	1.7	16.2	N			Mica Facility Asset Plan	Page 26	N	For Prioritization	10	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	F2020-F2021 RRA Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	F2020-F2021 RRA Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
39	G000220	Peace Canyon - 600V Circuit Breaker Upgrades	Sustaining	Definition	F2023	F2020	F2019	-		9.1 - 5.2	-	-	-	-	0.3	0.7	3.2	N			Peace Canyon Facility Asset Plan	page 29	N	For Prioritization	10	
40	G001008	Revelstoke - 600V Circuit Breaker Upgrades	Sustaining	Definition	F2022	F2020	F2018	-		13 - 10	-	-	-	10.9	0.3	3.7	6.2	N			Revelstoke Facility Asset Plan	Page 35	N	For Prioritization	10	
41	G003373	Revelstoke Replace Fire Alarm System	Sustaining	Definition	F2022	F2020	F2019	-		13.8 - 7.9	-	-	-	9.5	0.3	6.3	2.2	N			Revelstoke Facility Asset Plan	Page 35	N	For Prioritization	10	
42	G000334	Wahleach Refurbish Generator	Sustaining	Definition	F2022	F2020	F2018	-		52 - 44	-	-	-	41.7	12.0	13.5	13.4	Y		Page 48	Wahleach Facility Asset Plan	Page 44	N	For Prioritization	9.5	
43	G000042	Ash River Extend Life of Steel Penstock	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.4	0.6	0.7	N			Ash River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 5 and 31	N	For Prioritization	10	
44	G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	1.6	4.4	3.7	Y	CPCN	Page 50	Bridge River Facility Asset Plan	Page 7	N	For Prioritization	10.5	
45	G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.4	0.0	0.0	N	Potential s44.2	Page 49	Bridge River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 7 and 31	N	For Prioritization	10	
46	G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	24.7	1.0	9.5	12.6	N			Bridge River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 7 and 31	N	For Prioritization	10	
47	G000952	Kootenay Canal Modernize Controls	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	5.9	0.2	0.3	5.9	N		Page 54	Kootenay Canal Facility Asset Plan	Page 20	N	For Prioritization	10	
48	G000168	Lake Buntzen 1 - Generator Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.6	2.0	TBD		Page 65	Coquitlam-Buntzen System Facility Asset Plan	Page 24	N	For Prioritization	10	
49	G000169	Lake Buntzen 1 Penstock Exterior Recoat	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.6	1.5	N			Coquitlam-Buntzen System Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 24 and 31	N	For Prioritization	10.5	
50	G000741	Ladore - Redevelop Unit 1	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	2.6	6.6	N		Page 56	Ladore Falls Facility Asset Plan	Page 22	N	For Prioritization	10.5	
51	G003835	Peace Canyon - U1 - U4 Exciter Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.2	0.3	N			Peace Canyon Facility Asset Plan	Page 29	N	For Prioritization	10	
52	G000252	Revelstoke - U1 - U4 Stator Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.2	1.8	TBD	Potential CPCN or s44.2	Page 66	Revelstoke Facility Asset Plan	Page 35	N	For Prioritization	10.5	
53	G000834	Seven Mile - Replace T1 Transformer	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.3	2.0	1.4	N			Seven Mile Facility Asset Plan	Page 39	N	For Prioritization	10.5	
54	G000822	Seven Mile Upgrade Powerhouse Crane Controls	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.3	4.7	4.5	N			Seven Mile Facility Asset Plan	Page 39	N	For Prioritization	10	
55	G003026	Seton - Upgrade Unit	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.9	9.0	TBD		Page 57	Seton Facility Asset Plan	Page 37	N	For Prioritization	10	
56	G003449	Various Facilities Replace Water Level Gauges	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	0.4	0.4	N					N	For Prioritization	10	
57	G001047	Waneta U3 Life Extension	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	1.1	3.1	19.0	Y		Page 61			N	Mandatory		
58	G000219	Peace Canyon Upgrade HVAC System	Sustaining	Deferred	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.0	0.7	N			Peace Canyon Facility Asset Plan	Page 29	N	For Prioritization	9.5	
59	G000035	Ash River - Generator Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.6	N			Ash River Facility Asset Plan	Page 5	N	For Prioritization	10	
60	G000131	G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.1	0.3	N			G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	9.5	
61	G003336	G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.2	0.4	N		Page 63	G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	9.5	
62	G003826	G.M. Shrum - Pauwels Transformer Life Extension	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.1	0.4	N			G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	9.5	
63	G000133	G.M. Shrum - Transformers Phase 4 Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.7	3.1	N			G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	9.5	
64	G000130	G.M. Shrum - U1, 2, 4, 7, 8, 9, 10 Water Passage Refurbishment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.7	N		Page 64	G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	10	
65	G003837	G.M. Shrum - U5 Stator Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.1	Y			G.M. Shrum Facility Asset Plan	Page 13	N	For Prioritization	10.5	
66	G000966	Kootenay Canal - Fire Detection and Alarm System Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.2	N			Kootenay Canal Facility Asset Plan	Page 20	N	For Prioritization	9.5	
67	G003296	La Joie - South Penstock Refurbishment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.6	N					N	For Prioritization	9.5	
68	G000195	Mica - Intake Gantry Crane Refurbishment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	0.6	4.1	N			Mica Facility Asset Plan	Page 26	N	For Prioritization	9	
69	G003211	Mica - Reactor 5RX3 Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	18.6	2.7	13.5	2.1	N			Mica Facility Asset Plan	Page 26	N	For Prioritization	10	
70	G000183	Mica - U1 - U2 Turbine Overhaul	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	1.1	TBD	Potential CPCN or s44.2		Mica Facility Asset Plan	Page 26	N	For Prioritization	10.5	
71	G000181	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.4	2.5	Y			Mica Facility Asset Plan	Page 26	N	For Prioritization	10	
72	G000231	Peace Canyon - High and Low Pressure Piping Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.4	N			Peace Canyon Facility Asset Plan	Page 29	N	For Prioritization	9	
73	G000436	Seven Mile - U1 - U4 Controls Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.3	1.1	N			Seven Mile Facility Asset Plan	Page 39	N	For Prioritization	9.5	
74	G004166	Various Sites - PCB Lighting Remediation	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	0.9	-	-	2.6	2.3	N					N	For Prioritization	10	
75	G003338	Various Sites - Cutler Hammer Exciters Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.6	N					N	For Prioritization	10	
76	G003584	Whatshan - Governor Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.6	2.3	N					N	For Prioritization	9.5	
		Add: Programs and Projects Less than \$5M															75.8	70.8								
		TOTAL Hydroelectric															371.3	400.0								

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	F2020-F2021 RRA Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	F2020-F2021 RRA Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
		Diesel																								
		Add: Programs and Projects Less than \$5M												5.0			4.7									
		TOTAL Diesel												5.0			4.7									
		Thermal																								
77	G003189	Burrard - Modify for Post Generation Operations	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.1	3.3	N					N	For Prioritization	9	
		Add: Programs and Projects Less than \$5M												3.1			1.0									
		TOTAL Thermal												3.1			4.3									
		Generation Total												379.4			409.0									
		Portfolio Delivery Adjustment												(107.0)			(20.7)									
Total														272.4			388.4									

Note A: Subsequent to the Currency Date, BC Hydro decided to pause the Revelstoke Install Unit 6 project. Refer to Chapter 6, section 6.4.1.2 for more information.

Note B: The Revelstoke Install Unit 6 project was not assessed under the prioritization framework.

- Notes:
- (1) Information provided is current as of the established 'Currency Date' which is April 1, 2019.
 - (2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than \$5M".
 - (3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
 - (4) Forecast ISD is the expected in-service date for the project (as at the Currency Date).
 - (5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
 - (6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
 - (7) Implementation Approval \$ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
 - (8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
 - (9) Authorized Amount is the 'Authorized' total capital cost of the project as of the currency date.
 - (10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
 - (11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
 - (12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Order No. G-47-18 or Directive 29 of BCUC Order No. G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2022 RRA - Transmission
Projects greater than \$5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F22) as at April 1, 2019 (1), (2)
\$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	F2020-F2021 RRA Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	F2020-F2021 RRA Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Transmission																										
		Growth Capital Expenditures																								
		Regional System Reinforcement																								
1	92216	Peace Region Electric Supply (PRES) (Note A)	Growth	Implementation	F2022	F2019	F2017	284.6	F2022	N/A - In Implementation	284.6	7.6	-	177.9	59.4	8.1	39.4	Y	Exempt Project, M216.OIC 101	Page 71	Transmission Planning Study Peace Region Electric Supply Project	Page 75	N	Committed		
2	93845	Metro North Transmission (MNT)	Growth	Definition (Note C)	F2025	F2023	F2017	-		\$30 - 300	-	-	-	-	(6.5)	1.2	6.0	Y	CPCN	Page 73	Metro North Transmission Planning Report	Page 60	N	Prioritize	11.0	
3	92423	Bridge River Transmission Project	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	2.0	7.0	Y	CPCN	Page 75	Bridge River Transmission System Upgrade - NITS Study	Page 50	N	Prioritize	10.0	
4	901572	North Montney Region - Electrification	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	1.6	Y	CPCN				N	Prioritize	10.5	
5	900598	West End - Substation Construction and System Reinforcement	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	1.2	3.5	17.5	Y	CPCN	Page 80	Downtown Vancouver Electric Supply Plan	Page 54	N	Prioritize	10.5	
6	94034	West Kelowna Transmission and Westbank Upgrade Projects	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.8	2.6	7.0	Y	CPCN	Page 77	West Kelowna Area Study	Page 83	N	Prioritize	9.5	
7	901573	Bear Mountain Terminal – T4 Transformer Addition	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.1	0.6	Y	CPCN				N	Prioritize	10.5	
8	900994	Kamloops - Area Reinforcement	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	1.4	Y					N	Prioritize	8.0	
		Bulk System Reinforcements																								
9	900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.0	1.5	Y	CPCN	Page 84	Burrard Synchronous Condensers Replacement Study	Page 58	N	Prioritize	12.0	
10	90957	Peace to Kelly Lake Capacitors	Growth	Identification (Note C)	TBD	TBD	TBD	-		TBD	-	-	-	-	3.7	6.0	15.0	Y	CPCN	Page 82	Peace to Kelly Lake 500kV Transmission Reinforcement Study	Page 66	N	Prioritize	11.0	
		Station Expansion & Modification																								
11	93788	Capilano Substation Upgrade	Growth	Definition	F2025	F2020	F2018	-		94 - 74	-	-	-	-	3.8	7.7	15.4	Y		Page 87	Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 69	N	Prioritize	10.5	
12	92907	Mount Lehman Substation Upgrade	Growth	Definition	F2023	F2020	F2019	-		86 - 48	-	-	-	-	2.4	14.0	24.5	Y		Page 89	Abbotsford Area Study Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 46 and 51	N	Prioritize	11.0	
13	92910	Clayburn Substation Upgrade	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.6	3.1	18.8	Y		Page 91	Abbotsford Area Study Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 46 and 51	N	Prioritize	11.0	
14	900816	Pemberton - Substation Upgrade	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.2	2.0	Y		Page 95			N	Prioritize	10.0	
		Transmission Load Interconnections																								
15	93786	MIN to LNG Canada Interconnection (Note B)	Growth	Implementation	F2021	F2019	F2016	79.8	F2021	N/A - In Implementation	82.5	-	-	77.0	27.7	37.0	2.1	Y	Exempt Project, Transmission Upgrade Exemption Regulation				N	Mandatory		
16	94003	UBC Load Increase Stage 2	Growth	Implementation	F2022	F2018	F2015	55.2	F2022	N/A - In Implementation	55.2	-	-	48.5	23.1	8.6	6.0	Y					N	Mandatory		
17	901580	Customer IPID - 901580: [REDACTED]	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.7	3.2	Y					N	Mandatory		
18	901581	Customer IPID - 901581: [REDACTED]	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	0.8	5.5	9.1	Y					N	Mandatory		
		Add: Programs and Projects Less than \$5M															63.2									
		TOTAL Gross Growth Capital Additions													323.1		196.9									
		Less: Contributions in Aid of Construction																								
															(28.9)		(8.7)									
		Net Growth Capital Additions													294.2		197.2									
		Sustaining Capital Expenditures																								
		Circuit Breakers																								
19	900243	SPG Metalcad Switchgear Replacement	Sustaining	Definition	F2024	F2020	F2019	-		68 - 38	-	-	-	-	1.0	3.0	4.4	Y		Page 97	Sperling Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 71	N	Prioritize	10.5	
		Other Power Equipment																								
20	900575	Barnard 50/60 Feeder Section Replacement	Sustaining	Implementation	F2022	F2019	F2018	47.9	F2022	N/A - In Implementation	47.9	-	-	38.9	10.6	13.4	10.6	N		Page 98	Barnard Asset Plan	Page 48	N	Committed		
21	92073	American Creek - Capacitor Protection Control Upgrade	Sustaining	Definition	F2023	F2021	F2018	-		21 - 19	-	-	-	-	0.9	2.7	3.7	N			Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	N	Prioritize	9.5	
22	900564	Hundred Mile House T1/T2 EOL Replacement	Sustaining	Definition	F2023	F2020	F2019	-		34 - 11	-	-	-	-	0.9	2.0	7.1	Y			Asset Management Strategy - Section 2.2.16: Power Transformers	Page 81	N	Prioritize	10.0	
23	93731	Jordan River - Switchyard Upgrade	Sustaining	Definition	F2023	F2020	F2019	-		57 - 32	-	-	-	-	2.0	5.9	10.0	N		Page 101	Asset Management Strategy - Section 2.2.16: Power Transformers	Page 81	N	Prioritize	10.5	
24	92166	SC Excitation Systems Upgrade - VIT/KLY	Sustaining	Definition	F2024	F2020	F2014	-		14 - 11	-	-	8.4	-	0.4	4.7	2.0	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 74	N	Prioritize	10.5	
25	92618	VIT & KLY Hydrogen Gas Sys - Safety Upgrade	Sustaining	Definition	F2024	F2020	F2017	-		9 - 7	-	-	3.7	-	(0.1)	1.8	2.1	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 74	N	Committed		
26	900247	Bridge River - T4 Transformer Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.2	1.1	6.8	N		Page 99	Asset Management Strategy - Section 2.2.16: Power Transformers	Page 81	N	Prioritize	10.5	
27	93705	K11 60Kv Renovation, 4Kv Decommission & Control Room	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.3	0.4	N			Kidd 1 Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 56	N	Prioritize	9.5	
28	92478	Mainwaring Station Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.1	0.7	6.4	Y	CPCN	Page 103	Mainwaring Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 59	N	Prioritize	10.5	
29	900152	Natal Sub - NTL 60-138 kV Rebuild	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.7	1.3	1.0	Y		Page 105	Natal Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 62	N	Prioritize	10.5	
30	94079	Sandspit Substation Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.2	0.4	2.4	Y			Wood Pole Substation Strategy	Page 84	N	Prioritize	9.0	
31	94081	Ah-sin-heck - Substation Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.5	4.2	Y			Wood Pole Substation Strategy	Page 84	N	Prioritize	8.5	
32	901618	Kelly Lake - Reactor Installation	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.5	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 74	N	Prioritize	9.0	
33	901248	Kimberley to Marysville - Substation Relocation	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	1.0	N			Asset Management Strategy - Section 2.2.2: Circuit Breakers	Page 51	N	Prioritize	10.0	
34	901613	Maple Ridge - Feeder Section 60 Series Refurbishment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.1	Y					N	Prioritize	10.0	
35	901034	Norgate - Substation Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.0	0.5	Y		Page 108	Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 69	N	Prioritize	9.5	
36	92759	Patricia - Substation Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.5	2.8	N			Patricia Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 65	N	Prioritize	9.5	
37	900185	Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.6	5.3	N		Page 107	Asset Management Strategy - Section 2.2.10: Shunt Reactors	Page 67	Y	Prioritize	10.0	
		Protection and Control																								
38	900625	NERC CIP V5 Compliance at Medium Impact T&D Stations	Sustaining	Implementation	F2023	F2019	F2018	35.5	F2023	N/A - In Implementation	35.5	-	-	-	3.3	2.7	2.0	N		Page 109	Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	N	Mandatory		
39	900250	Control PLC984 and RTU Replacement (WSN)	Sustaining	Definition	F2023	F2020	F2017	-		10 - 8	-	-	-	-	0.2	1.0	3.5	N			Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	N	Prioritize	10.0	
40	93687	GMS Substation - Control Systems Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.3	2.4	4.4	N			Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	N	Prioritize	10.0	
41	901592	Various Sites - NERC CIP-003v7 Implementation	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	8.8	12.8	N			Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	N	Mandatory		
		Stations Auxiliary Equipment																								
42	93690	Stn Service Transfer & AC panels - WSN	Sustaining	Implementation	F2022	F2017	F2016	11.8	F2019	N/A - In Implementation	11.8	-	-	15.3	1.0	2.9	3.5	N			Asset Management Strategy - Section 2.2.16: Power Transformers	Page 81	N	Committed		
43	900726	Joseph Creek (JOE) Substation Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.1	0.5	5.5	N			Wood Pole Substation Strategy	Page 64	N	Prioritize	9.0	
44	901045	Canal Flats - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.1	1.0	Y			Wood Pole Substation Strategy	Page 64	N	Prioritize	9.0	
45	901244	Cathedral Square - Substation HVAC Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.5	2.1	N					N	Prioritize	10.0	
46	901249	Elko - Switchyard Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.3	1.9	N			Wood Pole Substation Strategy	Page 64	N	Prioritize	8.5	
47	901048	Lumby #2 - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	2.2	N			Wood Pole Substation Strategy	Page 64	N	Prioritize	9.0	
48	901040	Port Alberni - Substation Refurbishment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	1.6	N					N	Prioritize	9.5	
49	901049	Skookumchuck - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.1	1.6	Y			Wood Pole Substation Strategy	Page 64	N	Prioritize	9.0	
50	900724	Woss - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.1	1.8	N			Wood Pole Substation Strategy	Page 64	N	Prioritize	8.5	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	F2020-F2021 RRA Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	F2020-F2021 RRA Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
		Stations Risk Mitigation																								
51	92158	Oil Spill Containment - F17/F18 (ALZ / MDN)	Sustaining	Definition	F2022	F2020	F2017	-		8 - 6	-	-	-	7.8	1.1	3.3	1.4	N			Asset Management Strategy - Section 2.2.8: Oil Spill Containment	Page 63	N	Prioritize	10.0	
52	94052	Stations Sessmic Upgrade -F16/17 (9 Stations)	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	0.3	0.4	N					N	Prioritize	9.0	
53	900766	Project IPID - 900766	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	3.1	1.1	Y					N	Prioritize	9.0	
54	901407	Various Sites - Substation Security Upgrades (F2021)	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	6.0	1.6	4.0	-	N					N	Committed		
		Telecommunications																								
55	92183	Vancouver Island Radio System	Sustaining	Implementation	F2022	F2018	F2014	32.5	F2021	N/A - In Implementation	32.5	-	-	25.6	8.4	5.8	4.0	N		Page 111	Asset Management Strategy - Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	N	Committed		
56	92768	Various Sites - Telecom MPLS and DACS Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	3.2	13.4	N		Page 112	Asset Management Strategy - Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	N	Prioritize	10.0	
57	900709	Various Sites - Telecom Analog Private Line Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	0.9	5.0	N					N	Prioritize	9.5	
58	900019	Various Sites - Microwave Radio Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	2.5	N			Asset Management Strategy - Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	N	Prioritize	10.0	
		Cable Sustainment																								
59	901002	2L146 - Cable Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.9	1.6	TBD		Page 113	Asset Management Strategy - Section 2.1.10: Transmission Cables	Page 77	N	Prioritize	10.0	
60	94057	Gulf Islands - Transmission Reinforcement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	6.8	TBD		Page 115	Asset Management Strategy - Section 2.1.10: Transmission Cables	Page 77	N	Prioritize	10.0	
61	901623	Coquillam - 2L51 Partial Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	2.0	5.0	TBD			Asset Management Strategy - Section 2.1.10: Transmission Cables	Page 77	N	Prioritize	10.0	
		O/H Lines Life Extension																								
62	92840	Circuit Refurbishments - F15 - 2L13/14	Sustaining	Definition	F2022	F2020	F2015	-		N/A	-	-	-	17.8	2.6	12.3	1.0	Y			Asset Management Strategy - Section 2.1.11: Transmission Wood Poles	Page 86	N	Prioritize	10.0	
63	93729	Long Span Crossing Refurbishment - F17/F18 (1L37)	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.0	2.6	N			Asset Management Strategy - Section 2.1.2: Conductors	Page 76	N	Prioritize	9.0	
64	94035	5L63 Telkwa Relocation	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	5.1	2.7	9.8	N		Page 116			N	Prioritize	10.5	
65	901789	Various Sites - Transmission Copper Conductor Replacement - F2021	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	1.2	5.0	-	6.2	-	N			Asset Management Strategy - Section 2.1.2: Conductors	Page 76	N	Prioritize	10.0	
		Third Party Requested Transmission Line Relocations																								
66	901232	60L029 - Transmission Relocation (MoTI Protocol Agreement)	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.1	1.7	2.4	N					N	Mandatory		
		Add: Programs and Projects Less than \$5M													156.2		153.6									
		TOTAL Gross Sustaining Capital Additions													272.6		325.6									
		Less: Contributions in Aid of Construction													(8.0)		(5.3)									
		Net Sustaining Capital Additions													264.6		320.3									
		Transmission Total																								
		Net Growth Capital Additions													294.2		187.2									
		Net Sustaining Capital Additions													264.6		320.3									
		Portfolio Delivery Adjustment													(155.0)		(53.0)									
		Total													403.8		454.5									

Note A: The Implementation Approval \$ (H) and Authorized Amount (K) for the Peace Region Electric Supply (PRES) project exclude contributions from the Federal Government while the Capital Expenditure and Capital Addtion figures are net of contributions.

Note B: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance

Note C: The Metro North Transmission (MNT) and Peace to Kelly Lake Capacitors projects were cancelled subsequent to the Currency Date of information. Please see Chapter 6, section 6.4.2.1 for further discussion of the projects.

Notes:

(1) Information provided is current as of the established 'Currency Date' which is April 1, 2019.

(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than \$5M".

(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.

(4) Forecast ISD is the expected in-service date for the project (as at the Currency Date).

(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.

(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.

(7) Implementation Approval \$ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.

(9) Authorized Amount is the 'Authorized' total capital cost of the project as of the currency date.

(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.

(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.

(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Order No. G-47-18 or Directive 29 of BCUC Order No. G-246-20.

Use of To Be Determined (TBD):

For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2022 RRA - Distribution

Projects greater than \$5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F22) as at April 1, 2019 (1), (2)

\$ Million

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	F2020-F2021 RRA Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	F2020-F2021 RRA Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Distribution																										
		Growth Capital Expenditures																								
		Customer Driven																								
1	DY-1545	Customer IPID - DY-1545	Growth	Definition	F2025	F2020	F2019	-		N/A	-	2.0	-	-	2.0	0.4	0.4	Y					N	Mandatory		
2	901588	Customer IPID - 901588	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	25.0	5.6	Y					N	Mandatory		
3	901589	Customer IPID - 901589	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	7.8	3.2	Y					N	Mandatory		
		Add: Programs and Projects Less than \$5M													235.7		236.0									
		Total Customer Driven													235.7		244.8									
System Expansion and Improvement																										
4	92802	Glenmore Voltage Conversion (LM-NSC-088) (Note A)	Growth	Definition	F2020	F2022	F2013	-		5 - 3	-	0.0	-	5.3	0.0	-	5.3	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	10.5	
5	93650	Two new CBN Feeders (LM-FVE-606) (Note A)	Growth	Definition	F2022	F2021	F2015	-		7 - 3	-	0.1	-	-	0.1	2.7	4.2	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	8.5	
6	93669	Three new MLE Feeders to offload CBN (LM-FVE-607) (Note A)	Growth	Definition	F2022	F2021	F2015	-		13 - 8	-	0.1	-	-	0.1	1.8	4.1	Y					N	Prioritize	8.5	
7	900347	CAP distribution voltage conversion for 51.52.58 (LM-NSC-124)	Growth	Definition	F2022	F2021	F2018	-		9 - 5	-	0.0	-	3.8	0.0	0.0	3.7	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	9.5	
8	900364	CAP distribution voltage conversion for 57, and 59 (LM-NSH-040)	Growth	Definition	F2022	F2021	F2018	-		7 - 4	-	0.1	-	3.4	0.1	-	3.4	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	10.5	
9	901132	Two Fleetwood feeders to offload McLellan (FV-FVW-723)	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	0.3	0.5	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	8.0	
10	900309	Burnaby - Voltage Conversion Home Payne 12F316 & 12F59 to 25F123 (LM-BBY-075)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	0.8	2.6	Y					N	Prioritize	9.0	
11	900310	Burnaby - Voltage Conversion and Transfer Home Payne 12F312 & 12F74Q to 25kV (LM-BBY-076)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.5	2.8	Y					N	Prioritize	9.0	
12	900431	Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.4	3.5	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	11.0	
13	900541	Vancouver Island - Saltspring 25F61 Submarine Cable Extension to North Pender Island (VI-GUL-005)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.8	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	8.5	
14	901354	Glenmore - Voltage conversion of GLR 452, 454, 461, 462, 463 & 464 (LM-NSH-047)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.5	2.4	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	11.0	
15	901355	Norgate - Offload NOR loads to NVR feeders (LM-NSH-074)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.8	6.5	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	11.0	
16	901356	North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.2	3.0	Y			Distribution Planning Practice Sections 6.1 6.4.2		N	Prioritize	11.0	
		Add: Programs and Projects Less than \$5M													52.8		18.4									
		Total System Expansion and Improvement													65.3		61.2									
Uneconomic Extension Assistance																										
		Total Gross Growth Capital													301.7		306.7									
		Less: Contributions in Aid of Construction													(149.5)		(199.4)									
Net Growth Capital Additions														152.2107.4												
Sustaining Capital Expenditures																										
System Expansion and Improvement																										
17	900391	Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown (Note A)	Sustaining	Implementation	F2022	F2019	Note B	26.6	F2021	N/A - In Implementation	26.6	0.8	-	-	0.7	5.4	10.4	N					Y	Committed		
18	900557	H-Frame Elimination - Chinatown	Sustaining	Implementation	F2022	F2016	Note B	48.4	F2019	N/A - In Implementation	48.4	1.5	8.4	0.5	11.9	3.6	0.1	N		Page 118			Y	Committed		
		Add: Programs and Projects Less than \$5M													45.7		61.9									
		Total System Expansion and Improvement													46.2		62.0									
Asset Replacement																										
19	900556	Various Sites - LED Street Light Conversion	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	9.1	25.1	1.7	10.0	28.9	N		Page 120	Asset Management Strategy – Section 3.1.8: Street Lighting	Page 88	N	Prioritize	10.0	
		Add: Programs and Projects Less than \$5M													128.4		127.4									
		Total Asset Replacement													153.5		156.3									
Electric Vehicle Charging Infrastructure																										
															0.3		(0.2)									
Beautification																										
															1.2		1.2									
		Total Gross Sustaining Capital													201.2		219.3									
		Less: Contributions in Aid of Construction													(0.8)		(0.8)									
Net Sustaining Capital Additions														200.4218.5												
Distribution Total																										
Net Growth Capital Additions																										
Net Sustaining Capital Additions																										
Total														352.5325.9												

Note A: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance
Note B: This project was approved directly to Implementation and the Definition Phase Activities were completed under the overall Program Management

- Notes:
- (1) Information provided is current as of the established 'Currency Date' which is April 1, 2019.
 - (2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than \$5M".
 - (3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
 - (4) Forecast ISD is the expected in-service date for the project (as at the Currency Date).
 - (5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
 - (6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
 - (7) Implementation Approval \$ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
 - (8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
 - (9) Authorized Amount is the 'Authorized' total capital cost of the project as of the currency date.
 - (10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
 - (11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
 - (12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Order No. G-47-18 or Directive 29 of BCUC Order No. G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2022 RRA - Technology
Projects and Programs greater than \$2 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F22) as at July 1, 2019 (1), (2)
\$ Million

	A		B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	IPID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No	Current or Potential Application, Y=Yes, N=No (11)	F20 RRA Appendix J Reference (different currency date)	Technology Strategy & 5 Year Plan (Appendix F) Business Outcome References	F20 RRA Appendix K Reference - Strategy, Plan or Study (different currency date)	Program of Projects or Related Planning IDs	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
			Manage Compliance and Security																								
			Projects Over \$2 million																								
1	T001604	YT-00861	FileNet records Retention and Disposition	Sustaining	Definition	F2021	F2020	F2018	TBD	TBD	TBD	0.6	-	-	3.3	0.3	1.2	0.9	N	N/A	N/A		N/A	N/A	Committed	10	N/A
			Sub-total Projects over \$2 million												3.3		0.9										
			Projects and Programs less than \$2 million												6.6		9.0										
			Subtotal (Compliance and Security)												9.9		9.9										
			Manage Risk and Sustain Productivity																								
			Projects over \$2 million																								
2	T001572	YT-01102	Windows 2008 Upgrade to Windows 2016	Sustaining	Identification	F2022	TBD	TBD	TBD	TBD	N/A	0.0	-	2.8	1.8	0.1	2.3	2.2	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10	N/A
3	T001682	YT-00856	PSSP/WPP Replacement	Sustaining	Identification	F2021	TBD	TBD	TBD	TBD	N/A	0.0	-	-	2.7	0.3	1.5	0.3	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10.5	N/A
4	T001397	YT-00623	Contact Centre Technology Foundation	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	11.3	-	7.0	1.0	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	11	N/A
5	T001719	YT-01148	SharePoint Workspaces Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	6.0	0.7	4.0	0.5	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	T001577/T002004	for Prioritization	10	N/A
6	T002085		Advanced Metering Software Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	-	0.7	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10.5	N/A
7	T002036	YT-01096	Energy Management System 3.X Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	5.5	0.3	3.0	2.4	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	11	N/A
8	T002258		SAP Customer Front End Replacement	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	0.7	-	-	0.7	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	11	N/A
9	T002317		Secondary Data Centre Network Refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	-	4.0	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10	N/A
10	T002321		Primary Data Centre Network Refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	-	3.3	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10.5	N/A
11	T002324		Operations Centres Network Refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	-	1.0	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10	N/A
12	T002483		Windows 2012 Upgrade to Windows 2016	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	3.0	-	-	3.0	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10	N/A
			Sub-total Projects over \$2 million										-	-	31.0	1.5	17.8	19.0									
			Programs over \$2 million																								
13	T002208	YT-01261	Storage Capacity Growth F22	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	3.5	-	-	3.5	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10	N/A
14	T002304		PC Device Purchase F22	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	3.8	-	-	3.8	N	N/A	N/A	Resilient and secure IT and OT systems	N/A	N/A	for Prioritization	10	N/A
			Sub-total Programs over \$2 million										-	-	7.3	-	-	7.3									
			Projects and Programs less than \$2 million												40.9		34.3										
			Subtotal (Risk and Productivity)												79.2		60.6										
			Enhance Business Capability																								
15	T001127	YT-00486	Supply Chain Applications	Sustaining	In-Service	F2021	F2019	F2016	42.4	2020-03-23	N/A	68.8	-	68.0	0.3	26.6	8.0	0.3	N	Y	3698901	Optimized supply chain function	N/A	N/A	Committed		1.0
			Sub-total Projects over \$2 million												0.3		0.3										
															-		-										
			Projects and Programs less than \$2 million												8.2		8.2										
			Subtotal (Business Capability)												8.5		8.5										
			Portfolio Adjustment												(10.0)		(10.0)										
			Total												87.6		69.0										

Notes:
(1) Information provided is current as of the established 'Currency Date' which is July 1, 2019. Information for certain projects in progress has been updated for significant events subsequent to this date.
T001127 has been updated to reflect information at September 30, 2020.
(2) Some projects that are in service or forecast to be in service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Projects and Programs less than \$2 million".
(3) Project / Program dollars are generally capitalized in the Definition phase.
(4) Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date.
(6) Fiscal Year that the project received Definition phase approval.
(7) Implementation Approval \$ refers to the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation. "N/A" is used for recurring programs.
(8) Pre-implementation cost estimates are determined in the Definition phase, and represent the most recent engineering estimate. If not in the Definition phase then N/A, and if no engineering estimate then TBD. See Appendix S, pp. 6-65 to 6-67, for further discussion on pre-Implementation phases.
(9) Amounts reflect only the capital portion of the Authorized amount.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation. "N/A" is used for recurring programs.
(11) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Order No. G-47-18 or Directive 29 of BCUC Order No. G-248-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start Date of Construction, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Appendix I - F2022 RRA - Properties
Projects greater than \$5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F22) as at April 1, 2019 (1), (2)
\$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No	Current or Potential Application, Y=Yes, N=No (11)	F20 RRA Appendix J Reference (different currency date)	Technology Strategy & 5 Year Plan (Appendix F) Business Outcome References	F20 RRA Appendix K Reference - Strategy, Plan or Study (different currency date)	Program of Projects or Related Planning IDs	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
1	P201704	Materials Classification Facility Building Redevelopment	Sustaining	Definition	F2022	F2020	F2017	-		N/A	-	-	4.6	38.0	1.3	12.6	22.6	N	N	page 125	N/A	N/A	N/A	For Prioritization	9.5	N/A
2	P201703	Chilliwack Field Building Redevelopment	Sustaining	Definition	F2023	F2021	F2017	-		N/A	-	-	7.0	-	0.2	13.0	11.2	N	N	page 123	N/A	N/A	N/A	For Prioritization	10	N/A
3	P202001	Campbell River II Field Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.7	9.0	N	N	N/A	N/A	N/A	N/A	For Prioritization	9.5	N/A
4	P201901	Kamloops Field Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	3.2	6.0	N	Y	page 127	N/A	N/A	N/A	For Prioritization	9.5	N/A
5	P202101	Duncan Field Building Redevelopment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	6.0	-	-	6.0	1.0	N	N	N/A	N/A	N/A	N/A	For Prioritization	9.5	N/A
6	P201902	North Vancouver Field Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.7	2.0	N	N	N/A	N/A	N/A	N/A	For Prioritization	9.5	N/A
7	P202102	Cranbrook Field Building Redevelopment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	1.0	2.0	N	N	N/A	N/A	N/A	N/A	For Prioritization	9.5	N/A
8	P202113	Coquitlam Roof & Interiors Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.3	2.8	N	N	N/A	N/A	N/A	N/A	For Prioritization	9	N/A
9	P202012	Dunsmuir Roof & Interiors Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.1	2.7	N	N	N/A	N/A	N/A	N/A	For Prioritization	11	N/A
		Add: Programs and Projects Less than \$5M	Sustaining	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple				43.2	21.8		25.6	16.4									
		TOTAL												59.8			75.6									

Notes:
(1) Information provided is current as of the established 'Currency Date' which is April 1, 2019.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than \$5M".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project (as at the Currency Date).
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval \$ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
(9) Authorized Amount is the 'Authorized' total capital cost of the project as of the currency date.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Order No. G-47-18 or Directive 29 of BCUC Order No. G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2022 RRA - Other
Projects greater than \$5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F22) as at April 1, 2019 (1), (2)

Million																										
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No (11)	Current or Potential Application, Y=Yes, N=No (12)	F20 RRA Appendix J Reference (different currency date)	Technology Strategy & 5 Year Plan (Appendix F) Business Outcome References	F20 RRA Appendix K Reference - Strategy, Plan or Study (different currency date)	Program of Projects, Y=Yes, N=No	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Other Capital																										
1	900864	Mobile Radio Optimization - LM	Sustaining	Implementation	F2022	F2016	F2016	9.5	F2019	N/A	9.5	-	-	6.7	0.8	2.0	0.2	N	N		N/A		N	Committed		
2		Fleet/Vehicles	Sustaining	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	29.2	31.4	27.2	27.0	31.4	27.2	N	N		N/A			Committed	9	
		Business Support - Other																								
3	93632	Project IPID - 93632	Growth	Identification	TBD	TBD	TBD	-	TBD	-	-	10.9	2.0	0.1	10.6	6.0	N	N	N		Squamish Area Reinforcement Study		N	For Prioritization	9	
4	901654	Advanced Distribution Management System Replacement	Sustaining	Future	TBD	TBD	TBD	-	TBD	-	-	-	8.9	-	5.3	-	N	N	N		N/A		N	For Prioritization	10	
5	FC-00392	Materials Management - Oil Management Operating Infrastructure	Sustaining	Definition	TBD	TBD	TBD	-	TBD	-	-	2.8	0.6	2.9	6.5	N	N	N	N		N/A		N	For Prioritization	8.5	
6	YM-00153	Learning & Development - Energized Training Substation	Sustaining	Future (Note A)	TBD	TBD	TBD	-	TBD	-	-	-	8.2	-	3.5	4.7	N	N	N		N/A		N	For Prioritization	10-11	
		Add: Programs and Projects Less than \$5M																								
		Total													48.0		43.1									
		Total Fleet / Other													81.9		70.5									

Note A: Learning & Development - Energized Training Substation project was cancelled subsequent to the Currency Date of information. Please see Chapter 6, section 6.5.4

- Notes:**
- (1) Information provided is current as of the established 'Currency Date' which is April 1, 2019.
- (2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than \$5M".
- (3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
- (4) Forecast ISD is the expected in-service date for the project (as at the Currency Date).
- (5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
- (6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
- (7) Implementation Approval \$ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
- (8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
- (9) Authorized Amount is the 'Authorized' total capital cost of the project as of the currency date.
- (10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
- (11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
- (12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Order No. G-47-18 or Directive 29 of BCUC Order No. G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2022 RRA - Site C
Projects greater than \$5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F22) as at April 1, 2019 (1), (2)
\$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval \$ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Forecast F21	Capital Addition Forecast F22	Capital Expenditure Actual F20	Capital Expenditure Forecast F21	Capital Expenditure Forecast F22	Extension Project, Y=Yes, N=No	Current or Potential Application, Y=Yes, N=No (11)	F20 RRA Appendix J Reference (different currency date)	Technology Strategy & 5 Year Plan (Appendix F) Business Outcome References	F20 RRA Appendix K Reference - Strategy, Plan or Study (different currency date)	Program of Projects or Related Planning IDs	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
1		Site C	Growth	Implementation	F2024 (Unit 1)	F2016	F2015	7,575.2	F2024 (Unit 1)	N/A	10,005.0	12.9	197.5	-	1,619.1	1626.0	1361.0	Y	Exempt per Clean Energy Act, sec. 7(1)				N	Committed		
		Total																								

Notes:
(1) Information provided is current as of the established 'Currency Date' which is April 1, 2019. Information for certain projects in progress has been updated for significant events subsequent to this date.
(2) Some projects that are in service or forecast to be in service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Projects and Programs less than \$2 million".
(3) Project / Program dollars are generally capitalized in the Definition phase.
(4) Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date.
(6) Fiscal Year that the project received Definition phase approval.
(7) Implementation Approval \$ refers to the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation. "N/A" is used for recurring programs.
(8) Pre-Implementation phases are: Future, Identification and Definition. See Appendix S, pages 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-implementation cost estimates are provided in Definition phase. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.
(9) Amounts reflect only the capital portion of the Authorized amount.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation. "N/A" is used for recurring programs.
(11) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Order No. G-47-18 or Directive 29 of BCUC Order No. G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start Date of Construction, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix J

Capital Expenditures > \$20 million

As this is a one-year “gap year” Revenue Requirements Application for Fiscal 2022 only, BC Hydro is not providing this appendix as part of the Application. BC Hydro will provide this appendix as part of its Fiscal 2023 Revenue Requirements Application and has deliberately left this appendix blank to maintain the continuity of the appendices related to capital expenditures and additions.

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix K

Summaries of Capital Project Strategies, Plans and Studies

As this is a one-year “gap year” Revenue Requirements Application for Fiscal 2022 only, BC Hydro is not providing this appendix as part of the Application. BC Hydro will provide this appendix as part of its Fiscal 2023 Revenue Requirements Application and has deliberately left this appendix blank to maintain the continuity of the appendices related to capital expenditures and additions.

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix L

Project Write-off Costs

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1 Introduction

In its Decision on the Previous Application, the BCUC acknowledged that some project write-offs are reasonable and to be expected in a utility's normal course of business.¹ The BCUC suggested that a regulatory account could be considered as a mechanism to capture BC Hydro's actual project write-off costs for future recovery, provided that:

...in future RRAs BC Hydro also lists all of the projects and costs that have been written-off and captured in the regulatory account along with a description of each project, the rationale for incurring the costs and the rationale for the decision to not continue with the project. In the Panel's view, this would provide the BCUC and interveners with an opportunity to review the reasonableness of these costs.²

In response to Directive 33 of the BCUC's Decision on the Previous Application, BC Hydro made a separate application for approval to establish a Project Write-off Costs Regulatory Account.³ BC Hydro's request to establish the Project Write-off Costs Regulatory Account was approved by BCUC Order No. G-337-20 dated December 17, 2020. The purpose of the account is to defer, on an ongoing basis effective starting in fiscal 2020, actual project write-off costs in each fiscal year where BC Hydro believes future recovery from ratepayers is appropriate.

In the Application, BC Hydro has proposed a recovery mechanism for the account, which is described in Chapter 7, section 7.2.4.

In accordance with the suggested process from the Decision on the Previous Application, this Appendix lists the projects and costs that have been written-off and captured in the regulatory account, a description of the projects, as well as the

¹ BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), p. 107.

² BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), p. 107.

³ Refer to: <https://www.bcuc.com/ApplicationView.aspx?ApplicationId=833>.

rationale for incurring the costs and the rationale for not continuing with the projects or reducing the scope of the projects.

2 Information Considered for Project Write-Off

Project write-offs are determined with reference to the accounting rules BC Hydro is required to follow. BC Hydro uses International Financial Reporting Standards (IFRS) guidance in reviewing capital projects for any asset impairment. Specifically, International Accounting Standards (IAS) 36 – *Impairment of Assets* – provides the following guidance:

An entity shall assess at the end of each reporting period whether there is any indication that an asset may be impaired. If any such indication exists, the entity shall estimate the recoverable amount of the asset.

Active capital projects are not yet assets in service, but from an accounting perspective are still assets on the balance sheet classified as work in process. BC Hydro reviews capital projects each month based on the standard noted above for any internal or external information to determine if an impairment exists and if so, the amount of the project that needs to be written off. If a project or any part of the project is to be written off, a justification is prepared by the project manager and presented to the appropriate level of management for approval, depending on the amount of the write-off.

Projects are similarly reviewed throughout the project lifecycle. Specifically, at the end of each phase of the project lifecycle,⁴ BC Hydro determines whether a project should proceed to the next phase of the project lifecycle, be cancelled or be reduced in scope. If a project is cancelled or reduced in scope, the expenditures on that project are reviewed against the standard noted above to determine any impairment and resulting write-off.

⁴ Project lifecycle phases can be seen in Appendix S, Figure 6-13.

Pursuant to the processes outlined above, key reasons why an impairment may occur and a write-off may be required include the following:

1. **Cost:** Detailed design work may indicate that the costs of the original leading alternative are higher than originally planned, which may result in another alternative being more cost-effective. If it is determined that another alternative will be pursued as a result, some or all of the costs incurred in respect of the original leading alternative may hold no future value (i.e., are impaired) and may be required to be written off;
2. **Technical Issue:** Detailed engineering work may indicate that the original leading alternative has technical issues that were not previously known. Examples are challenges associated with retro-fitting new equipment with existing equipment of a different vintage, or the identification of damage or poor condition of assets that were not being replaced once a sealed asset is opened. Another example of a technical issue is where information developed may reveal a new alternative that is determined to be superior to the original leading alternative. If these examples result in changes to the leading alternative or the pursuit of another alternative, some or all of the costs incurred to that point may be impaired and may be required to be written off;
3. **Business Driver:** Business factors, such as the load forecast, could push the need for a project that is current underway to a future period. In this instance, depending on factors such as the length of time before the project may be needed in future and the likelihood of future need, some or all of the costs incurred to that point may be impaired and may be required to be written off; and
4. **Customer's Need:** A project to interconnect a customer may be cancelled or the scope changed because the customer has changed its request. A customer could also cancel a load request that had a reinforcement project to existing BC Hydro assets to support the new load. In this instance, some or all of the

costs incurred to that point may be impaired and may be required to be written off.

3 Project Write-Offs in Fiscal 2020 and Fiscal 2021

In its Previous Application, BC Hydro forecast project write-offs totalling \$9.9 million in fiscal 2020, and \$9.7 million in fiscal 2021.⁵ Actual project write-offs in fiscal 2020 were \$11.9 million, which was comprised of \$15.2 million less customer contributions of \$3.3 million. BC Hydro is not seeking recovery of \$2.6 million of this amount as BC Hydro does not believe it would be reasonable for ratepayers to pay for the costs in these instances. Accordingly, BC Hydro has deferred \$9.3 million (\$11.9 million minus \$2.6 million) to the Project Write-off Costs Regulatory Account in fiscal 2020, and proposes to recover this amount from ratepayers in fiscal 2022.

The table below provides the itemized project write-offs.

⁵ The fiscal 2020 and fiscal 2021 forecast project write-offs are discussed in Chapter 8, section 8.11 of the Previous Application.

Project Name	Amount Deferred (\$ million)	Project Description	Rationale for Write-off
Metro North Transmission Project	6.5	This project was initiated in 2013 to meet the expected demand as several major circuits in the network would experience capacity constraints in the coming years. The preferred alternative for this project was to construct a new 10.5 km overhead circuit and 9 km of underground circuit from Meridian and Horne Payne substations via Port Moody/Anmore/Burnaby and a new crossing over the Burrard Inlet. An additional 8.7 km of underground circuit would be extended from the Horne Payne substation to the Mount Pleasant substation.	Business Driver change. The load forecast at the time of initiating the project indicated the need to increase the load supply capability in the Metro Vancouver region. Based on the June 2019 Load Forecast, BC Hydro determined that the need to increase the load supply capability in the Metro Vancouver region can be delayed until after fiscal 2029 due to a reduction in the forecast load growth in the Metro Vancouver region. As a result, BC Hydro cancelled the Metro North Transmission Project, and wrote off the capital expenditures to date. BC Hydro will continue to evaluate the need to increase the load supply capability in the Metro Vancouver region in the future.
Williston Station Service Transfer & AC Panels	3.1	The project involves the replacement of switches and panels at Williston Substation (WSN) south east of Prince George that are at the end of their useful life.	Technical Issue. The Peace to Kelly Sustainment Project (PKSP) replaced the scope of this project, as BC Hydro determined that a new control building would address multiple business needs at the Williston Substation. As a result, \$3.1 million of the \$7.3 million incurred to date related to the project scope that is no longer required was written off. The remaining \$4.2 million was transferred to the PKSP project.

Project Name	Amount Deferred (\$ million)	Project Description	Rationale for Write-off
Peace Region to Kelly Lake 500kV Transmission Reinforcement (renamed Peace to Kelly Lake Capacitors Project (PKCP))	0.9	The PKCP was initiated in 2016 to increase the transfer capacity of the 500 kV transmission system to meet the forecasted transfer demand based on the planning criteria in the 2013 Integrated Resource Plan. As well, the project would address reliability risks associated with some of the equipment in the 500 kV transmission system that is reaching end of life. The leading alternative identified at the end of the Identification Phase Conceptual Design Stage was to construct three new 500 kV series capacitor stations, replace end of life shunt reactors at Willison Substation (WSN) and Peace Canyon Substation, replace aging protection & control (P&C) equipment, modify the 500 kV bulk system Remedial Action Scheme (RAS), and decommission the Kennedy Capacitor Station.	Business Driver change. BC Hydro determined that the need for an increase in the transfer capability along the Peace Region to Kelly Lake transmission corridor to deliver power to the load centers in the south of the province could be delayed until after fiscal 2031. This was due to the June 2019 load forecast which showed surplus generation capacity available in the system and the capability to reliably serve load with the current transfer capability beyond fiscal 2031. As a result, BC Hydro has canceled the project. The sustainment portion of the project was grouped into a new project – the Peace to Kelly Lake Sustainment Project (PKSP). Accordingly, \$0.9 million of the \$3.2 million incurred to date is related to project scope that is no longer required and was written off. The remaining \$2.3 million was transferred to PKSP.

Project Name	Amount Deferred (\$ million)	Project Description	Rationale for Write-off
CMC-PUN Flow Control Improvement	0.7	The Comox-Puntledge (CMC-PUN) Flow Control Improvement Project was initiated to improve the ability to manage water conveyance at CMC-PUN in a controlled and safe manner. The leading alternative identified at the end of Conceptual Design Stage included the following scope items: • CG-A – Upgrade of the Generation Conveyance Control System; • CG-B – Upgrade of the Comox Dam Sluiceway gates; • CG-C – Upgrade of the Comox Dam Right Abutment; • CG-D – Installation of a Puntledge Diversion Dam Storage Buffer; and • CG-E – Improvement of Operator Decision Support.	Cost change. During the Feasibility Design Stage, the project team developed designs for the five scope items and it was established that the total project cost was \$17 million or 77 per cent higher than forecast in the Conceptual Design Stage. The project objective was redefined, focusing on reducing risk to public safety due to misoperation or malfunction during normal operations. The project write-off is associated with the CG-D (Installation of a Puntledge Diversion Dam Storage Buffer) scope of work, which was not advanced to Definition Phase as the redefined project objective could be met without including this item in the project scope.

Project Name	Amount Deferred (\$ million)	Project Description	Rationale for Write-off
Prince George to Terrace Capacitors (PGTC)	2.2	The PGTC project was originally initiated in 2012 to supply potential LNG loads on the North Coast. Subsequently, a number of major customers cancelled their projects and load interconnection requests. As a result, the existing transfer capacity of the 500 kV transmission system became sufficient to meet the capacity required by the remaining customers, and the project was cancelled. In 2019, the PGTC project was reinitiated to accommodate new load interconnection requests, to improve reliability and maintain BC Hydro's ability to implement the project in time to meet customer needs in response to Government of B.C.'s CleanBC Plan. The interconnection customer has not yet made a final investment decision.	Customer's Need change. The anchor customer driving the need for the original PGTC project cancelled their own project. \$1.6 million of the \$2.4 million in Work-in-Progress was transferred to the re-initiated PGTC project because it related to overall system reinforcements. The remaining \$0.8 million in capital expenditures were determined to have no future value and were written-off. The customer contribution of \$3.0 million was transferred to revenue at the time of the original write-off. BC Hydro proposes to provide the benefit of this contribution to ratepayers. Therefore, the net write-off is a credit of \$2.2 million (\$3 million revenue less \$0.8 million write-off).
Project Write- Offs equal or less than \$300k	0.3	Various minor expenditures on projects (each less than \$300,000) across the capital portfolios.	
Total Write-Off Amounts	9.3		

**BC Hydro Fiscal 2022
Revenue Requirements Application**

Appendix M

**Fiscal 2022 Demand-Side Management Program
Descriptions and Data Tables**

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1 Introduction

2 This appendix provides details on BC Hydro's demand-side management activities
3 for fiscal 2022. [Section A](#) provides detailed descriptions of activities within each
4 DSM program and initiative. [Section B](#) provides financial tables showing
5 expenditures, energy and capacity savings, and cost-effectiveness by program and
6 initiative. [Section C](#) provides the portfolio-wide assumptions used in modelling the
7 cost-effectiveness of the programs.

Section A: Program Overviews

1 Residential Sector Programs

1.1 Residential Sector Overview

BC Hydro's residential sector has almost 1.8 million customer accounts and sales to this sector total approximately 17,400 GWh annually,¹ representing over 30 per cent of BC Hydro's annual load. The average residential account consumes about 9,900 kWh annually, although this varies widely with the type of home and the type of heating fuel used.

1.1.1 Residential Sector Strategic Approach

Residential programs are designed to take into consideration: the opportunities identified in research, through program benchmarking, and feedback from the marketplace; the need to reduce the barriers that exist for customers to adopt technologies or behavioural changes; and partnerships that can be leveraged to successfully bring these programs to market. Programs are offered focusing on specific customer segments as well as specific products.

At the end of fiscal 2020, B.C.'s provincial health officer declared COVID-19 a public health emergency. COVID-19 has resulted in financial hardship for a number of residential customers and has impacted participation in and delivery of some of our Residential programs. Where applicable, we have taken into account the impacts of COVID-19 on our Residential programs in the fiscal 2022 Plan.

For fiscal 2022, Residential programs will continue to focus on delivering a variety of initiatives that will help customers achieve energy savings, increase their energy literacy, and make it easier to do business with us. This includes:

¹ Sales by Revenue, June 2020.

-
- 1 • Providing customers with access to energy data information, such as tools,
2 graphs, charts and reports that, amongst other things, identify unusual
3 consumption and changes in electricity consumption;
 - 4 • Utilizing supporting partnerships with both the private and public sectors and
5 leveraging additional funds from channel partners and other government
6 sources, to ensure maximum customer benefit and market impact;
 - 7 • Leveraging the BC Hydro Power Smart brand and customer relationships to
8 move customers towards existing channels that offer opportunities for electricity
9 savings, while improving the ability of those channels to better meet our
10 customers' needs;
 - 11 • Using customer analytics to better target customers who are more likely to
12 participate in certain offers, ensuring that the right message reaches the right
13 customer, via the right channel;
 - 14 • Providing channel partners with significant support through training and
15 technical expertise to ensure that customers are better served in their purchase
16 and installation of energy efficient equipment; and
 - 17 • Building relationships with customers and channel partners, allowing BC Hydro
18 to further adapt to changing customer needs, and to assist with potential future
19 programs such as capacity-focused DSM.

20 **1.2 Low Income Program**

21 **1.2.1 Overview**

22 The Low Income program helps BC Hydro's lower income customers reduce their
23 energy consumption and lower their BC Hydro bills with a holistic and free energy
24 efficiency program offer. Low income households in both owner-occupied and rental
25 accommodations are eligible. There are three key components to this program that
26 together seek to address both the breadth and depth of our lower income customers'

1 needs: Energy Savings Kits, the Energy Conservation Assistance Program and the
2 Indigenous Communities Conservation Program (for grid-connected customers).
3 These components are described in the table below.

4 Since 2010, BC Hydro has partnered with FortisBC Energy Inc. to reduce costs and
5 improve the effectiveness of providing this program to low income customers across
6 the province. FortisBC Inc. is running a similar program modelled after the BC Hydro
7 Low Income program in its electric territory. BC Hydro is also coordinating with
8 Pacific Northern Gas in its service territory on delivery of the Low Income program.

9 In fiscal 2021, public health concerns due to the COVID-19 pandemic led the
10 program partners to temporarily suspend the in-home work conducted through our
11 Energy Conservation Assistance Program for the first half of the year. The program
12 resumed regular work at the end of quarter two but will not be able to recover the
13 participation needed to achieve the planned energy savings in fiscal 2021. Impacts
14 in fiscal 2022 are expected to be relatively small.

Annual Plan	\$ million	GWh/yr
F2022	7.4	8
Target Market	Lower Income Residential Customers (Statistics Canada's Low Income Cut-off threshold +30 per cent). Both owner occupied and renters.	
Key Components	Energy Saving Kits	
	Energy Conservation Assistance Program	
	Indigenous Communities Conservation Program (BCH Grid connected customers)	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	\$21	(\$32)
Benefit Cost Ratio	1.2	2.6

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Utility bill savings • Provides free access to energy efficient technologies and home improvements • Improved home comfort and safety • Increased knowledge of ways to lower energy bills • Supports owners and renters	• Supports B.C.'s home performance retrofit industry	• Reduces BC Hydro's overall cost of service (lowers the revenue requirement) • Contributes to the shareholder's affordability mandate • Generates positive earned media and customer satisfaction • Meets the Demand-Side Measures Regulation • Supports relationships with Indigenous communities • Supports the FortisBC Partnership

1 1.2.2 Description

	Detailed Description
Energy Savings Kits	The Energy Savings Kit is a package of basic energy saving measures provided at no charge that can be installed by most homeowners or tenants with limited or basic tools. Energy Savings Kits contain lighting-related products, water saving products (e.g., faucet aerators and a high performance showerhead), heat-loss products (e.g., draft proofing material, and window film) and general energy savings tips and brochures. The program expanded to provide participants window film on an annual basis at no cost. Window film is only used for one heating season and then removed. In addition, Energy Savings Kits are provided at pre-qualified events (e.g., foodbanks, and Indigenous community events). Approximately 35 per cent of recent participants have been renters or tenants.
Energy Conservation Assistance Program	The Energy Conservation Assistance Program provides eligible BC Hydro low income Residential customers with a home evaluation, installation of energy saving products and education on what customers can do around their homes to save energy. There is no charge for the products or services provided through the program. Some of the energy saving products that may be installed include energy saving light bulbs, low-flow showerheads and faucet aerators, pipe wrap, draft proofing (e.g., door sweeps), an Energy Star refrigerator, a high-efficiency gas furnace (in conjunction with FortisBC Energy Inc.), and insulation for attics, walls and crawlspaces. Program criteria have been revised to enable more homes to receive weatherization upgrades and the refrigerator replacement offer was expanded to apartments run by non-profits and co-op housing providers. A trial was launched on mobile homes to determine the technical feasibility and expected electricity savings of installing high-efficiency mini-split heat pumps, results will inform future program rollout. Over the past two years, approximately 75 per cent of participants have been renters or tenants.

	Detailed Description
Indigenous Communities Conservation Program	For customers on the integrated electricity system, the Indigenous Communities Conservation Program partners with communities (Bands) to support and encourage them to include energy efficiency measures when undertaking home renovations within their communities through their own channels. The program provides free energy savings products, training and salary support for Bands to hire community members to install the products and review energy upgrade opportunities in homes. The program also supports advanced weatherization measures through a rebate model which will enable communities to combine multiple funding sources and lead to more extensive home renovations. The rebate offer includes a training component for Bands and their installers/contractors on best practices for air sealing and insulation retrofits in B.C.

1.3 Retail Program

1.3.1 Overview

BC Hydro seeks to influence our residential customers to purchase more energy efficient products and leverages the retail channel to activate these transactions. The Retail program aims to advance the adoption of more energy efficient products by working with market partners to have the energy efficient products available on store shelves throughout B.C. at affordable price points, supported by knowledgeable sales staff.

The Retail program reaches large numbers of customers in a channel that they can utilize throughout the year, while offering a variety of low cost options or upgrades for residential customers (owners and renters) to become more energy efficient. Due to the partnerships with retailers (e.g., Home Depot, Best Buy) and manufacturers (e.g., Philips, Samsung), this program is able to leverage additional exposure in the form of flyer advertising, e-newsletters, websites and instore promotion, additional customer sales support from retail sales staff, and further discounting on products funded through manufacturers.

Key manufacturer and retailer channel partners are targeted to influence products stocked, promoted and how they are positioned. These partners represent the

1 largest market share and widest exposure across the province. The Retail program
2 leverages the potential for low-cost and far-reaching public exposure through
3 partner's flyers, promotions and space in-store. Joint utility and municipality
4 collaboration allows for increased rebate offers to customers, operational efficiencies
5 and enhanced customer experience. These partnerships, channels to market, and
6 opportunities to leverage consumer engagement enable a platform for new offers
7 such as connected home technology or demand response capable devices. The
8 Retail program is also designed to increase the market penetration of energy
9 efficient products to set the stage for collaborating with governments and standards
10 agencies to help encourage changes to energy efficient regulation.

11 In fiscal 2021, BC Hydro cancelled the spring campaign of the Retail program due to
12 the COVID-19 pandemic. In addition, we downsized the fall awareness campaign to
13 avoid being in market during the build up to the provincial election. There was still
14 digital communication to drive awareness throughout fiscal 2021, and during the
15 COVID-19 pandemic we began a larger online focus to align with the overall market
16 pivot towards online shopping during the COVID-19 pandemic. This greater online
17 focus expedited the migration that the program was already making towards a more
18 robust online presence and offer.

Annual Plan	\$ million	GWh/yr
F2022	2.2	7
Target Market	Residential customers who purchase product through the retail channel. Can include both owner occupied and renters (for lower cost product investments). Key partnerships are with retailers like Best Buy, Home Depot, Costco and a variety of appliance, lighting, electronics, and home improvement product manufacturers.	
Key Components	Channel partnerships	
	Product Incentives	
	Advertising and promotions (often provided by the retailer/manufacturer partners)	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	(\$23)	(\$7)
Benefit Cost Ratios	3.2	2.6

Customer Benefits	Channel Partner Benefits	BC Hydro & Shareholder Benefits
- Better accessibility and availability of products - Reduced cost to purchase - Utility bill savings - Other non-energy benefits depending on the appliance/product (e.g., extra features, water savings etc.) - Easy to participate with low cost options for renters and home owners - Education and awareness - Customer satisfaction	- Increase sales with incentives and in-store execution - Campaign promotions and fulfilment educates their customers and drives traffic to their stores - Leverage other program initiatives - Partner satisfaction	- Reduces BC Hydro's overall cost of service (lowers the revenue requirement) - Positive public exposure in partner owned channels by leveraging long-standing relationships - Customer and channel partner satisfaction - Established channels to market can ease the expansion of any future customer offers - Supports Codes and Standards

1 **1.3.2 Description**

	Detailed Description
Channel partnerships	The Retail program works with select retailers, manufacturers and supporting partners in order to collaborate on addressing market barriers to purchasing energy efficient products. Aligning with retailers who represent the largest market share, BC Hydro maximizes its resources and its partners' resources to increase participation, awareness and ultimately drive adoption of energy efficient products. Complementary manufacturing partnerships are chosen to further influence the campaign offers, driving participation, awareness and adoption. BC Hydro partners with FortisBC to reduce program costs, increase customer incentives and make it easy for customers to participate. BC Hydro runs campaigns through the year that target various end-use categories. This approach to campaign management provides operational efficiencies while maximizing the time that offers are in market and available to assist customers. Partnering with local governments, BC Hydro is able to leverage municipal funding available to reduce water use and GHGs to increase customer incentives, drive participation, and make it easy for customers to do business with us. In fiscal 2020 the program began exploring more online promotions and sales with online retailers as well as some key thermostat manufacturers. These concepts will be further explored with increased online activations through major existing retail partners and exploration of an online marketplace to further expand this space.
Incentives	The Retail program provides incentives across a range of products. Downstream incentives are offered to residential customers to reduce the cost to purchase energy efficient products, driving awareness and partner engagement. The program provides mid-stream incentives where appropriate to retailers, to position, promote and drive sales of energy efficient products.
Advertising and Promotion	Typically, twice a year, BC Hydro manages campaigns and offers with retailers and manufacturers. By supporting channel partners through advertising, promotions and program collateral, the program leverages partner flyer exposure and other promotional channels as well as additional incentives from retailers and manufacturers to customers. The exposure that retail partners provide BC Hydro helps to stimulate interest and excitement amongst our customers in ways that we would not be able to achieve on our own. In store events also provide BC Hydro an opportunity to educate customers on energy efficient products and behaviours.

2 **1.4 Home Renovation Rebate**

3 **1.4.1 Overview**

4 The Home Renovation Rebate program focuses on customers with electric heat,
 5 who typically have the highest electric bills as heating is normally 50 per cent of a
 6 home's energy consumption. The Home Renovation Rebate program seeks to

1 motivate these customers to undertake energy efficiency upgrades to their existing
2 homes, primarily focused on lowering their space heating load and hence making
3 their electric bills more affordable. The program promotes upgrades to building
4 envelopes (insulation, windows, draft proofing), space and hot water heating
5 systems, and ventilation, with a combination of rebates for single and multi-upgrade
6 improvements. The Home Renovation Rebate program is jointly administered with
7 FortisBC Energy Inc. and FortisBC Inc. and the Government of B.C., allowing
8 customers to access a single offer regardless of whether their homes are electric, or
9 gas heated.

10 In addition to direct incentives, the program communications are aimed at program
11 awareness and participation and educating consumers on energy efficient home
12 renovations. The Home Renovation Rebate program works with contractors,
13 providing program details, training, sales support and recommendations on
14 installation best practices in home energy retrofits to improve the availability and
15 quality of home energy retrofit services in B.C. This has been further augmented
16 with the introduction of a Program Registered Contractor designation for insulation
17 contractors as well as heat pump contractors. This initiative leverages our BC Hydro
18 Alliance infrastructure to work closely with contractors, provide best practice training
19 and our website provides a directory for customers to find and drive leads to
20 contractors that have earned this designation.

21 In fiscal 2021 the COVID-19 pandemic led to a slowdown in program participation in
22 quarter one as customers were hesitant to allow contractors into their homes,
23 resulting in an approximately 15 per cent reduction in applications. As the province
24 entered Phase 3 in the summer of fiscal 2021, participation returned to normal
25 levels.

Annual Plan	\$ million	GWh/yr
F2022	5.0	9
Target Market	Residential customers primarily with electric heating (owner and renter occupied buildings)	
Key Components	Incentives for building envelope improvements, heating systems, ventilation upgrades, and a multi-measure bonus	
	Coordinated application and partner rebates – FortisBC, province of B.C., municipalities (in development phase)	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	(\$34)	\$12
Benefit Cost Ratios	3.4	1.5

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Utility bill savings • Improved home comfort • Health, safety, comfort, and building durability as well as other non-energy benefits • Reduced maintenance • Easy access to coordinated utility program offers (one-stop-rebate shop)	• Increased sales of efficient products • Best practice training • Co-op advertising	• Reduces BC Hydro's overall cost of service (lowers the revenue requirement) • Support electrically heated customers to lower their bills • Align with Government of B.C. interests and helps support its CleanBC platform • Flexible program platform can be leveraged for additional partners and more complex future initiatives including demand response and low-carbon electrification

1 **1.4.2 Description**

	Detailed Description
Customer and contractor education	The program provides a variety of training opportunities to educate customers and contractors about advances in home energy efficiency
Program Incentives	The incentives are designed to reduce the customer's upfront cost of installing more efficient measures and technologies. Incentives also support consumer awareness of energy efficient technologies.
Partnerships and Coordination	The Program partners with FortisBC to offer a coordinated administrative and application platform for multiple home energy rebates. In addition, in fiscal 2019 the program expanded to include rebate partnerships with the Government of B.C. and several municipal governments to provide additional rebates for participants by leveraging the existing program platform. This approach has provided internal efficiencies and improved the customer experience in finding and accessing related program rebates.

2 **1.5 Non-Integrated Areas**

3 **1.5.1 Overview**

4 Since fiscal 2020, the DSM Plan has included a deeper focus on energy efficiency
5 activities and offers for customers living in Non-Integrated Areas (**NIA**) of BC Hydro's
6 service territory. Reduction of consumption in these areas reduces high-cost
7 electricity production as well as BC Hydro's GHG emissions from diesel generation.
8 The majority of the activities are for residential customers, but there is also a small
9 commercial component. These program offers are informed by pilot work conducted
10 in fiscal 2017 to fiscal 2019.

11 BC Hydro provides electricity to customers in NIA through a combination of diesel
12 generating stations owned and managed by BC Hydro and small hydro plants
13 (owned by BC Hydro or Independent Power Producers). NIA customers – including
14 Indigenous customers –are often subject to higher bills as a result of poor housing
15 construction and maintenance practices and severe weather conditions in some
16 remote areas.

Intervenors expressed a clear interest in and need for additional BC Hydro efforts to assist NIA communities in implementing DSM activities. BC Hydro has reflected this feedback in its plan by moving from a pilot in fiscal 2019 to a dedicated program for NIA communities. In addition, a technology trial is planned to test low flow water technologies identified by intervenors during the F2020 to F2021 Revenue Requirement Application as potential opportunities within the NIA.

This work stream includes residential and commercial program offers to assist NIA customers in saving electricity, reducing utility bills and improving home comfort, while helping NIA communities reduce their reliance on diesel generation, thereby reducing GHG emissions.

In fiscal 2021, the COVID-19 pandemic resulted in a slowdown of activities in many NIA communities due to concerns about health impacts originating from outside of the community and limited local healthcare infrastructure to deal with a crisis. This will result in lower energy savings in fiscal 2021. Impacts in fiscal 2022 and beyond are expected to be relatively small.

Annual Plan	\$ million	GWh/yr
F2022	1.4	1
Target Market	Indigenous and Non-Indigenous customers living in one of BC Hydro's Non-Integrated communities	
Key Components	Residential home energy upgrades	
	Commercial building energy upgrades	
	Community Support: training and salary support to enable DSM activities in Indigenous communities.	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	\$168	\$53
Benefit Cost Ratios	1.7	2.4

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
- Increased energy literacy - Improved home comfort and other non-energy benefits - Utility bill savings - Health, safety, and building durability - Reduced maintenance - Local economic development opportunities - Reduced reliance on diesel - Air quality and climate benefits (GHG reductions)	- Local economic development opportunities - Training and skill building opportunities	- Reduces BC Hydro's overall cost of service (lowers the revenue requirement) - Advancing Reconciliation through strengthened relationships and partnerships with Indigenous communities - Reputational benefits - Energy savings and GHG reductions

1 1.5.2 Description

	Detailed Description
Residential Home Energy Upgrades	Free basic energy saving measures, equivalent to those provided in the Energy Savings Kit, available to all residential customers.
	Home energy upgrades for income-qualified customers delivered through a direct install program.
	Indigenous Communities Conservation Program: Free basic energy saving measures and rebates on advanced measures to support NIA Indigenous communities in leading home energy upgrades for their community members. Training and salary support will be provided (see Community Support).
	Rebates for home energy upgrades conducted by residential customers.
Commercial Building Energy Upgrades	Direct install approach for commercial customers to support upgrades to commercial/community buildings.
	Rebates on energy saving measures installed by commercial customers.
Community Support	Salary support to Bands to hire community members who will receive training from BC Hydro on how to review energy upgrade opportunities and install basic energy saving measures in homes (Indigenous Communities Conservation Program). Financial support for energy-focused positions on Band Administrations and training.

1.6 Residential Energy Management Activities

1.6.1 Overview

The objective of the Residential Energy Management Activities is to provide information and tools that assist customers to optimize their energy use. These activities support BC Hydro's residential DSM programs, rates, and codes and standards efforts in achieving their respective energy management and market transformation objectives. The three key elements of the energy management activities include the Behaviour program, access to energy support tools, and industry support. Residential Energy Management Activities enable energy savings directly through the Behaviour program, and also enable and support savings that are reported under other residential sector programs.

The centre-piece of the Residential Energy Management Activities is the Behaviour program, which is designed to encourage residential customers to adopt more energy conscious behaviours and practices that lead to electricity savings and lower bills. The program relies on well-established behavioural change methods such as feedback and challenges through the Team Power Smart (**TPS**) offer. Customers do not need to invest in products. They only need to change how they use the products they already own. The high level of engagement and education associated with TPS also supports other Residential programs by raising awareness of these offers. TPS Mobile launched in fiscal 2021, further expanding access and ease of use.

Providing feedback and energy data is a powerful tactic that results in increased awareness and insights, which in turn lead to adjustments in the operation of a household to optimize energy use. Detailed in-home consumption feedback from smart meter data is offered to all customers through the Energy Visualization Portal (**EVP**) on the BC Hydro website and for more engaged customers in near real-time via home energy monitors. The EVP presents customers with different and customizable views of their electricity usage and can also view consumption

1 forecasts, download their data and subscribe to various alerts. These different
 2 analytics tools in the EVP increase awareness and understanding of consumption
 3 patterns among BC Hydro’s customers. A mobile version of EVP launched in late
 4 fiscal 2020, further expanding access and ease of use for this platform. Other
 5 support tools and activities are also included in this element.

6 Industry support is an important feature to provide customers with access to trained
 7 and qualified trade allies/supply-chain partners who can assist them in
 8 understanding their energy management options, providing an assessment, and
 9 completing their projects/making their purchases. While ensuring quality
 10 performance, these partnerships also lead to market push, ultimately resulting in the
 11 increased penetration of energy-efficient technologies and energy management
 12 solutions.

Annual Plan	\$ million	GWh/yr
F2022	5.0	16
Target Market	All Residential customers who require assistance to make the best decisions around energy management for their household. Can be utilized by owners and renters	
Key Components	Detailed consumption feedback	
	Energy reduction challenges with membership	
	Energy Management Coaching	
	BC Hydro Alliance of Energy Professionals (across all sectors)	
	External Workforce Capability Building (across all sectors)	
	Customer Information Support	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Personal, relevant and actionable recommendations and tips • Proactive engagement and guidance from BC Hydro on energy management issues • Opportunity to earn rewards through successful Team Power Smart Challenges • Utility bill savings • Assistance in accessing qualified products and industry expertise • Increased availability of products and expertise, as well as quality within industry • Energy management information, advice, and program access support • Often low cost/ no cost advice for both home owners and renters	• Contests, promotions, and offers driving customers to products and channels that help customers manage their energy use • Promotion of third-party tools that support energy data such as in-home monitors and future mobile applications • Training and support on available BC Hydro programs, technologies, and changes to codes and standards • Partners can expand their suite of products and service offerings to customers	• Utilizes smart meter data by presenting customers with rich and timely information • Provides a highly engaged and accessible group of customers for testing new products, services and programs and to act as advocates for energy management and as ambassadors for BC Hydro • Foundational platform from which to launch future new offers • The trade ally network effectively sells and promotes BC Hydro programs to customers • Market and technical insights including technology adoption, new customer opportunities and feedback on DSM program effectiveness • Ensuring there are well training trades to help reduce BC Hydro's risk of poor workmanship and/or unhappy customers • Communication channel with industry, and insight into various firms' expertise • The extensive relationships with industry allow for the introduction of new services and solutions in the future. • Reduce load on capacity constrained substations, improving reliability and deferring costly upgrades

1 **1.6.2 Description**

	Detailed Description
Detailed Energy consumption feedback	Customers receive access to tools that allow them to better understand their household electricity consumption by logging in to the MyHydro customer portal, where they can view graphs of their past consumption. These graphs allow them to analyze their hourly, daily, weekly, monthly and yearly consumption patterns. Comparing their consumption to the previous year and to similar homes allows customers to assess whether there are any opportunities to reduce their consumption. They can also see the impact of the outside temperature on their electricity consumption and subscribe to a free email reminder service to help them log-in on a frequent basis. These analytics tools increase customers' awareness of their electricity consumption and it empowers them to look for opportunities to take action to reduce their bill. Home Energy Monitors connect wirelessly to a customer's smart meter and provide real-time energy information from SMI data. These devices are constantly evolving and BC Hydro and Powertech work closely with industry leaders to ensure system compatibility and a seamless and positive customer experience.
Energy Challenges and membership through Team Power Smart	Customers can become a member of Team Power Smart. This provides them several benefits, including the opportunity to enter into a Challenge to reduce their household electricity consumption by 10 per cent or more below the previous year's consumption. If they are successful, they will receive a \$50 bill credit. A Maintenance Challenge is also available; if they stay at or below the lower consumption level that was accomplished during their successful Reduction Challenge they will receive a \$25 bonus. Challenge participants receive proactive reminders from BC Hydro to keep them engaged, status updates on how they are progressing with their Challenge and tips and advice on strategies and actions that can assist them in reaching their goal. A mobile version of the Team Power Smart application launched in fiscal 2021, providing greater and easier access for members that wish to stay engaged and understand their progress towards their 10 per cent goal. Team Power Smart members can participate in members-only contests and benefit from offers; they also receive tailored communications by mail and email including progress updates, practical tips, and motivational stories, etc. This offer benefits both home owners and renters.
Energy Management Coaching	Energy coaches provide personalized support to assist customers in assessing and undertaking home energy management upgrades. Coaching advice is delivered by phone or email, including support such as helping understand program offers and confirming product eligibility. Exploration is continuing around additional newer types of coaching tools.

	Detailed Description
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, manufacturers, distributors, retailers, and registered experts that will promote the use of energy management and efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to our customers within the context of DSM programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. The BC Hydro Alliance of Energy Professionals also enables Conservation and Energy Management to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified. With constant turnover in the distributor and retail channel, BC Hydro recognizes the need for substantial effort in regular training and education activities with sales associates. A coordinated approach with channel partners allows BC Hydro to take advantage of existing training infrastructure including product road shows, monthly meetings and online training to reach as many sales associates as possible around the province. This approach allows for sales associates to act as ambassadors for the program, as they educate and assist customers and drive sales of energy efficient products.
External Workforce Capability Training	A critical success factor for the DSM Plan is that there are available and accessible qualified installation contractors in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce and supporting the development of the professional home energy performance industry in B.C. by working with partners to support third party industry trades groups (e.g., the Home Performance Stakeholder Council), professional contractor training, and development and implementation of contractor accreditation and certification programs.
Customer Energy Information Support	BC Hydro assists our customers to resolve their energy related inquiries and become more educated on how to access our programs and energy saving opportunities. The Customer Support Centre – call centre provides a first call/email option for our customers to find out more about their specific energy inquiries. Additionally, they provide, through the Business Help Desk (a group of specialized agents), a channel of support for specific energy management program inquiries. The role of these specialized agents is being expanded in fiscal 2021 to provide greater support for residential customers.

2 Commercial Sector Programs

2.1 Commercial Sector Overview

BC Hydro's commercial sector, including small and medium businesses (**SMB**) and key account-managed large commercial customers, has over 210,000 sites with total

1 sales of over 17,000 GWh annually (about 30 per cent of total BC Hydro sales). The
2 average commercial site consumes over 67,000 kWh annually, although there is a
3 wide distribution of consumption among the various customer segments.

4 **2.1.1 Commercial Sector Strategic Approach**

5 The Commercial sector provides support and initiatives for customers to address
6 their diverse needs and barriers to energy management. Programs are designed to
7 take into consideration the technical and customer segment opportunities, the need
8 to reduce the barriers that exist for customers to adopt those technologies or
9 operational changes and developing partnerships that can be leveraged to
10 successfully bring these programs to market.

11 Using Strategic Energy Management (**SEM**) as a foundation, the suite of commercial
12 offers helps customers identify opportunities, adjust their business operations, and
13 implement capital projects. This approach will achieve cost savings, help customers
14 reduce their bills and support a trusted energy advisor relationship with customers
15 and BC Hydro. The commercial programs have been designed as flexible platforms
16 that can add new offers and services as customer needs evolve.

17 At the end of Fiscal 2020, BC's provincial health officer declared COVID-19 a public
18 health emergency. The pandemic has resulted in financial hardship for many of our
19 customers, particularly those that have experienced job loss, have had to close their
20 businesses, or are otherwise unable to work due to COVID-19. Different customer
21 segments from our large key account-managed customers to our SMB customers
22 are experiencing the effects of COVID-19 at varying degrees. While many customer
23 segments are proceeding with projects, there are some that have been impacted.
24 For instance, the health care sector foresees delays in proceeding with energy
25 efficiency projects in long-term care facilities during the health emergency. In
26 addition, over 12,600 BC Hydro COVID-19 Relief Fund applications were approved
27 for SMB customers who had to temporarily close their business due to COVID-19.

1 For fiscal 2022, Commercial programs will continue to monitor the impacts of
2 COVID-19 and make program adjustments as required. This customer sector will
3 continue to be supported through the following:

- 4 • Providing customers with access to energy data information, such as tools,
5 graphs, charts and reports that identify unusual building consumption and
6 changes in a building's energy performance;
- 7 • Supporting a SEM approach to integrating energy efficiency considerations into
8 ongoing customer business practices and company culture;
- 9 • Focusing on support to the customers that require our help the most, such as
10 SMB customers, and the Social Housing, Healthcare, Education, and
11 Government sectors, while still ensuring all customers have an opportunity to
12 participate;
- 13 • Raising awareness of the opportunities that exist for customers to save on their
14 electricity bill and integrate best practices in their operations and buildings;
- 15 • Working with the BC Hydro Alliance of Energy Professionals who assist
16 business customers find opportunities to save energy, install energy-efficient
17 products, and ensure product availability;
- 18 • Providing customers with significant support through training, technical
19 expertise, financing options, and funding to optimize the energy consumption in
20 their buildings;
- 21 • Support growth in market capability by continuing to support industry-driven
22 efforts by creating the appropriate tools and resources and educational
23 opportunities to deliver sustained, high quality services to the marketplace.
24 These efforts help to drive market transformation and assist in the adoption and
25 compliance of building codes; and

-
- Building relationships with customers centered on energy allowing BC Hydro to further adapt to changing customer needs, and to make informed decisions on potential future programs such as capacity-focused DSM.

2.2 Leaders in Energy Management – Commercial (LEM-C)

2.2.1 Overview

The Leaders in Energy Management – Commercial (**LEM-C**) program provides energy efficiency solutions to assist customers with their energy efficiency projects. LEM-C provides technical and financial support, resources, and tools to help customers focus on specific targeted energy conservation measures such as lighting systems and HVAC. The LEM-C program is intricately linked to the Commercial Energy Management Activities to help customers overcome the management and business barriers to energy efficiency. Customers have access to Energy Study funding to build the business case for electrical efficiency projects. Customers then have access to project incentives to reduce the payback required to make these projects financially feasible if needed. This approach will achieve cost savings, helps with affordability, and supports a trusted relationship with customers. This program targets BC Hydro's commercial segment from small and medium business to key account managed large commercial customers.

Given the design of the program and the relationship with the customers, it provides an important base to allow for the future addition of new initiatives as opportunities evolve in areas such as capacity-focused DSM offers.

Annual Plan	\$M	GWh/yr
F2022	8.6	37
Target Market	Public Sector (Healthcare, Education, Government), Social Housing sector, and Commercial customers. Small and Medium Business are also a key target.	
Key Components	Project Energy Study	
	Project Implementation Funding	
	Social Housing Retrofit Support Offer	
	BC Hydro Technical Expertise	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	\$2	(\$40)
Benefit Cost Ratios	2.2	3.0

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Bill savings: Reduce customers' electrical operating costs • Improve corporate culture • Remove financial barrier: Incentives to help overcome customers financial hurdle rates and lower project payback period to an acceptable level • Other non-energy benefits depending on the end-use/project (e.g., maintenance, enhanced building value etc.) • Supports customers that need assistance in the public sector and small and medium sized businesses	• Support advancement in technology: Increase market demand for more efficient end uses • Competitiveness: Builds more efficient and competitive facilities in B.C. • Economic: helps support the development of energy services to perform efficiency studies and equipment installations	• Reduces BC Hydro's overall cost of service (lowers the revenue requirement) • Reduces BC Hydro's overall cost of service (lowers the revenue requirement) • Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry achieve their goals • Foundational platform for capacity-focused DSM • Retain flexibility: The offer can be adjusted quickly to changing internal and external demands by scaling up or down, adding funding partners or new program measures • Support towards market transformation: Emphasis on market transformation and education of key stakeholders by providing the right tools and resources • Support customer service: Ability to integrate customer strategy initiatives as necessary to ensure optimized delivery of offers

1 **2.2.2 Description**

	Detailed Description
Project Energy Study	The Project Energy Study provides customers with detailed technical information, quantified energy information and expected implementation costs for specific projects. The study can be used to determine the most effective energy conservation measure for implementation that best fits the customer's needs. Energy Study eligibility criteria is only available to organizations with BC Hydro sponsored Energy Managers, Energy Manager Associates, and a select number of strategic Key Account customers.

	Detailed Description
Project Implementation Funding	Project Implementation funding is available either through online customer self-serve for simple retrofits or in-depth custom projects for larger customers to reduce the capital costs of installing efficiency measures. Business Energy Saving Incentives (BESI) is an online process for simple one-to-one retrofits covering a wide range of technologies that is supporting all sizes of customers, particularly small and medium sized businesses. Custom project implementation incentives are available to help customers reduce the capital cost of implementing a custom project identified by the project energy study. For these larger customers, following a review of their energy study, customers can receive a capital incentive to proceed with their custom project. Project implementation incentive eligibility criteria are only available to organizations with BC Hydro sponsored Energy Managers, Energy Manager Associates, and a select number of strategic Key Account customers. Project Implementation incentives are also available to perform a comprehensive overhaul of a building's operations and scheduling. The act of increasing building performance through improved operations (as opposed to equipment retrofits) is referred to as recommissioning (e.g., reducing equipment run time during unoccupied hours). Industry standards and technology advances, particularly in the area of software (e.g., artificial intelligence), are facilitating the development of new types of software tools to improve and optimize building operations.
Social Housing Retrofit Support Offer	The Social Housing Retrofit Support Offer for Multi-Unit Residential buildings provides an opportunity for qualified social housing providers (e.g., BC Housing, and the B.C. Non-Profit Housing Authority) to minimize their operating costs and improve whole building performance of their facilities through the more efficient use of natural gas and electricity. This offer is a partnership between FortisBC Energy Inc., FortisBC Inc., BC Hydro and the Government of B.C. (through CleanBC) and is offered throughout the British Columbia service territories of the utilities. Customers can utilize any of the four offers below: • Energy study funding to review the potential energy conservation measures; • Implementation support that provides engineering design, tendering and project management; • Rebates for upgrading eligible technologies for lighting, HVAC and commercial kitchen; and • Rebates for CleanBC low-carbon electrification opportunities
BC Hydro Technical Expertise	BC Hydro will provide project specific internal technical assistance and support to the customer throughout a project to allow for an integrated customer experience. Tools, such as project calculators, are also created to further support the customer that allows for a cost-effective support model.

2.3 Commercial New Construction Program

2.3.1 Overview

The Commercial New Construction program is in its final years of operation as it ramps down and is replaced by a policy, codes & standards approach. As part of this transition, these final projects receive financial support for the design and implementation of new high performing buildings.

Based on initial customer and industry feedback, COVID-19 has not impacted the new construction industry. This can be attributed to BC's Restart Plan Phase 1 that included the construction industry and construction sites operating during COVID-19 while taking necessary precautions. Planned Commercial New Construction program projects are in progress and are expected to complete by fiscal 2023.

The Commercial New Construction program provided a foundation of energy efficiency support and initiatives for customers, while building capability to transform the new construction market, leveraging new technology capabilities in the marketplace, and adapting to changing customer needs.

The program has provided technical expertise and funding in the form of design and modelling support, energy studies, and personalized coaching for the design and implementation of cost-effective energy efficiency measures and building systems that exceed building code requirements.

The Commercial New Construction program is also well established to assist in improving compliance levels with the B.C. Building Code and the Vancouver Building Bylaw given BC Hydro's expertise and interaction with different industry players. The program is playing a role to increase the compliance level of these codes by focusing on industry education, building information data sharing and including program requirements for all Whole Building Design projects to be physically inspected. By supporting aggressive energy efficient building requirements and

- 1 seizing the “one-time” opportunity to incorporate those measures into design and
- 2 construction of new commercial buildings, the program also provides both support
- 3 for the introduction of ongoing more aggressive building codes and the compliance
- 4 of current codes and standards.

Annual Plan	\$ million	GWh/yr
F2022	1.9	6
Target Market	New Construction projects focusing on Healthcare, Education, Government, and Social Housing sectors, as well as support for other Commercial/Multi-unit Residential developers/owners.	
Key Components	Pre-engagement: Design team kick off meeting	
	Energy Study Proposal	
	Energy Study	
	Project Implementation Incentives	
	BC Hydro Technical Expertise	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	(\$2)	\$11
Benefit Cost Ratios	2.6	1.6

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
- Bill savings: Reduce customers' electrical operating costs via energy efficient construction and operation of buildings - Make smart choices with their power: Access to energy information and providing tools and new technologies, allowing customers to optimize energy efficiency and construct buildings that are more desirable for occupants - Other non-energy benefits depending on the project (e.g., enhanced building value and lease rates etc.) - Remove financial barrier: Incentives to help overcome customers' financial hurdle rates and lower project payback period to an acceptable level	- Platform to support market transformation through energy efficient design: Identify energy savings by promoting and funding the design of energy efficient buildings that exceeds the minimum building code legislation required, providing industry training and education to help condition the market for the introduction of the next building code. Furthermore, this transformation strategy serves to increase the level of compliance with the current building code - Support advancement in building design, systems and technology: Increase market demand that supports research, demonstration and development towards more efficient buildings and technologies	- Reduces BC Hydro's overall cost of service (lowers the revenue requirement) - Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry achieve their goals - Support customer service: Ability to integrate customer strategy initiatives as necessary to ensure optimized delivery of offers - Retain flexibility: The program focus can be adjusted as the adoption of the BC Energy Step Code progresses, and new opportunities such as low-carbon electrification arise

1 2.3.2 Description

	Detailed Description
Pre-engagement: Design team kick off meeting	The program is currently winding down, for the final customer projects there is a design team kick-off meeting in the early stages of building design. It's essential for the success of the potential Energy Study to have a design team kick-off meeting with the customer, design team, and BC Hydro program representatives to ensure a good understanding of program's requirements and deliverables. This step occurs prior to submitting the Energy Modelling Study Proposal. This initial step helps customers and BC Hydro determine if there is a viable opportunity to explore. The Project Workbook contains preliminary building and/or equipment information and estimates for the project as well as relevant contact and project team information.

	Detailed Description
Energy Study Proposal	After a design kick off meeting is conducted, and the project meets program core eligibility requirements, the applicant must complete and submit a complete Energy Study Proposal Workbook to BC Hydro. The purpose of this submission is to document the project details, including design team to be involved in the study with qualification, building baseline, scope of work, and the study cost breakdown for funding approval consideration.
Energy Study	The Energy Study provides customers with detailed technical information, quantified energy information and expected implementation costs. The study can be used to determine the most effective energy conservation measure for implementation. The study, along with BC Hydro support, includes among other detailed analysis: • Reviewing modelled baseline and proposed energy consumption; • Electrical and Mechanical Systems requirements; • Building Envelope thermal bridging analysis; • Costing; and • Design options - bundled measures along with interactive effects
Project Implementation Incentives	Project Implementation incentives are available to help customers reduce the capital cost of implementing the identified measures. Upon review of the study, and subject to adherence to program rules and passing economic cost tests, customers are offered a capital incentive agreement for signature.
BC Hydro Technical Expertise	BC Hydro will provide project specific internal technical assistance and support to the customer throughout a project to allow for an integrated customer experience.

2.4 Commercial Energy Management Activities

2.4.1 Overview

The objective of the Commercial Energy Management Activities is to provide information and tools that assist customers to optimize their energy use. These activities also support BC Hydro's commercial DSM programs, rates, and codes and standards efforts in achieving their objectives. By encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and company culture through a SEM approach, BC Hydro can both increase the confidence in, and quantity of DSM savings. As a result of these energy management activities, energy efficiency projects are more likely to come forward and realize energy savings within the LEM-C program.

1 The Commercial Energy Management Activities provide customers support through
2 strategic energy management training and resources (including Commercial Energy
3 Managers), whole building investigation, and support required to enable the
4 customer to implement, operate, and maintain facility changes through participation
5 in the LEM-C program. As part of these activities, building energy monitoring and
6 optimization are implemented to better understand and use customer energy data to
7 improve their energy performance and increase building efficiency. The flexible
8 design of the activities and the established relationships with the different customer
9 segments establishes a platform for potential new offers such as capacity-focused
10 DSM and low-carbon electrification.

11 In addition, customers have access to trained and qualified trade allies/supply-chain
12 partners to help them assess facility opportunities, complete their projects, and
13 access energy information support. Customer interest from utilizing energy
14 information generates market pull, while our partnerships (supply-chain and other)
15 can lead to market push, ultimately resulting in the increased penetration of energy-
16 efficient technologies and energy management solutions. These relationships with
17 industry will also allow for a relatively seamless addition of new offers in the future.

Annual Plan	\$ million	GWh/yr
F2022	6.2	n/a
Target Market	All Commercial customers who require assistance to make the best decisions around energy management for their business. Can be utilized by public sector, small and medium business, and private sector.	
Key Components	Energy Management Assessment and Plan	
	Energy Managers	
	Building & Refrigeration Automation Specialists	
	Whole Building Investigation	
	Small and Medium Business Building Optimization	
	Energy Wise Network / Campaign in a Box	
	BC Hydro Alliance of Energy Professionals	
	External Workforce Capability Building	
	Customer Information Support	
	BC Hydro Technical Coaching	

1

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
- Energy management information, advice, and program access support - Assistance in accessing qualified energy management products and industry expertise - Increased availability of energy management expertise and quality within industry - Improve corporate culture around strategic energy management - Low-cost/no-cost support is particularly beneficial for the public sector and small and medium businesses	- Energy Management as a career has grown including all the associated support services - Training and support on BC Hydro programs, various technologies, and changes in codes and standards - Business development – Partners are able to expand their suite of products and services to customers - Support advancement of new energy efficient products and services	- Improved communication channel with industry and customers - The trade ally network effectively sells and promotes BC Hydro programs to customers - Market and technical insights including technology adoption and new customer opportunities are more easily surfaced - Market feedback on DSM program effectiveness - Risk mitigation by ensuring engineering consultants and contractors are trained and qualified - Foundational platform for future offers to this customer segment such as demand response - Reduce load on capacity constrained substations, improving reliability and deferring costly upgrades

1 **2.4.2 Description**

	Detailed Description
Energy Management Assessment and Plan	Energy Management Assessment: A diagnostic workshop with an organization's senior management to review practices and procedures regarding the organizations energy management practices to move them towards best practices and feed into the SEM Plan. SEM Plan: A one to three-year plan that captures strategic (i.e., corporate policies, metrics, targets), enabling (i.e., recognition, behavioural change, organizational structure) and functional (i.e., operating procedure, procurement, reporting) energy management components. The plan identifies energy savings opportunities and aligns with corporate budgets and targets.
Energy Managers	The Energy Manager represents the critical first step – secure a dedicated energy champion within an organization that can work with the company's senior management team to help create and implement a corporate level strategic energy management program with targets. The Energy Manager also utilizes various tools and resources (i.e., energy data, capital incentives, energy study funding, and behavioural/operational initiatives) to ensure the company's energy policies and long-term goals are met through energy efficiency initiatives. Energy Manager Associates are available to key account customers without an Energy Manager and help customers take a strategic approach to energy management and create organizational change to reduce energy waste and improve energy intensity. They have access to educational and training events, resources and tools to develop SEM Plans, tracking and reporting templates, diagnostic workshops, and mentoring from BC Hydro funded Energy Managers. The Shared Energy Manager and the Business Energy Advisor is an adaptation of the Energy Manager model that is customized for small and medium business. These individuals will target select commercial customers utilizing various marketing techniques (i.e., propensity modelling) and introducing a SEM concept and approach within their organization. Building and Refrigeration Automation Specialists are available to key account managed customers that work with the company's facility management team to help create, implement, and manage an organization plan to increase building performance through improved building operations. Conservation and Energy Management will support and deliver technical training and education events for Energy Managers and Associates to further advance the skills and knowledge of best practices related to building systems, technology, and SEM.

	Detailed Description
Whole Building Investigation	The Whole Building Investigation study is used to determine the most effective energy conservation measures for implementation across an entire building or campus. The study also includes financial analysis based on the recommended energy conservation measure solutions that best fits the customer's needs. Small and Medium Business Building Optimization provides organizations with services to allow them to better manage their energy usage, identify operational based energy saving opportunities, and achieve additional energy savings by undertaking capital projects. The SEM Hub is an online tool to support customers in the strategic management of their portfolio of buildings aligned with historical and active energy efficient projects with the ability to run energy analytics. Customers can improve building operations by leveraging new tools that access more granular building energy information such as Anomaly Detection and Diagnostics, Cumulative Sum of Saving Tool (shows the cumulative savings from energy management measures implemented in a building relative to a defined baseline), Consumption trends and Energy Use Intensity.
Energy Wise Network / Campaign in a Box	Change management includes social marketing and behavioural economic techniques to target end users to ensure a culture of energy management is embedded within the organization which helps to change the behaviours of employees. The Energy Wise Network provides customers with education, campaign toolkits, diagnostic tools, mentoring support, and funding to implement campaigns to engage employees in their organization to use energy wisely. Campaign in a Box provides a scalable version for small and medium businesses to seamlessly adopt within their organization.
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, distributors and registered experts that will promote the use of energy management and efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to assist our customers within the context of DSM programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. BC Hydro has developed an online catalogue of energy efficient products that provides contractors, distributors, and manufacturers with easily accessible specifications of products that are supported within BC Hydro programs. The BC Hydro Alliance of Energy Professionals also enables Conservation and Energy Management to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified.

	Detailed Description
External Workforce Capability Training	A critical success factor for the DSM Plan is that there is an available and accessible “energy efficiency skilled” workforce in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce by partnering with post-secondary institutions and industry associations who develop and deliver new training and educational programs. The objective of education and training is to develop and build market capacity of individuals that will be qualified to become energy managers and energy champions within customer and industry organizations as well as to grow the pool of qualified individuals who can join trade ally firms. This will support program participation, increase awareness and action and ultimately integrate efficiency into ongoing business processes. This initiative includes integrating energy management modules within targeted disciplines of academic and training institutions as well as the development of materials to educate customers and trade allies. This provides support for students enrolled in post-secondary institutions, addressing the adequacy requirements of the Demand-Side Measures Regulation.
Customer Energy Information Support	BC Hydro assists our customers to resolve their energy related inquiries and become more educated on how to access our programs and energy saving opportunities. The Customer Support Centre (call centre) provides a first call/email option for our customers to find out more about their specific energy inquiries. Additionally, they provide, through the Business Help Desk (a group of specialized agents), a channel of support for specific energy management program inquiries.
BC Hydro Technical Expertise	BC Hydro will provide coaching on the customer’s portfolio of buildings and support to the customer throughout their energy management journey to allow for an integrated customer experience.

3 Industrial Sector Programs

3.1 Industrial Sector Overview

BC Hydro’s industrial sector is comprised of over 47,000 customer sites, from family-run farms to large mining operations, with total annual sales of 19,000 GWh/yr (over 30 per cent of total BC Hydro sales). The average industrial distribution voltage site consumes over 135,000 kWh annually and the average industrial transmission voltage site consumes over 90,000,000 kWh annually. Sectors that are the most likely to engage in BC Hydro’s industrial DSM programs include agriculture, manufacturing, transportation, forest products, pulp and paper, and mining.

3.1.1 Industrial Sector Strategic Approach

The Industrial programs are designed to capture DSM energy savings at industrial facilities by helping customers overcome the financial, technical, and business barriers to energy efficiency. By encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and company culture through a Strategic Energy Management (**SEM**) approach, BC Hydro can increase the quantity of DSM savings and alleviate potential substation capacity constraints.

Offers are available to all customer segments, with more focus on sectors that offer the largest and most cost-effective opportunities. The suite of offers includes financial resources as well as tools and education to help customers adopt a SEM model, identify and implement capital projects that will result in energy savings, and affect organizational culture to reduce energy waste and improve energy intensity. For new facilities or system retrofits, BC Hydro also helps customers identify efficiency opportunities with education, resources and funding. Where needed, BC Hydro provides incentives to support the implementation of capital projects that would otherwise not happen. This approach will achieve cost savings, help customers reduce their bills, and support a trusted relationship with customers.

As noted above, the COVID-19 pandemic created financial hardship for many of our customers, including some of our industrial customers. While we had forecast a reduction in participation rates in studies and incentive offers prior to COVID-19, the pandemic has reinforced the reduction in participation. We have taken into account these impacts in the fiscal 2022 forecast.

Participation in our SEM initiatives continues to be strong through the current economic climate and impacts of COVID-19. The reduction in SEM savings due to the impact on some of our customers will be offset by the number of new customers participating in SEM. To help mitigate any COVID-19 impacts on energy savings for fiscal 2022, the Industrial strategic approach will be to leverage SEM participant

activity to increase SEM savings to help offset impacts to savings due to decreased capital incentive projects.

For fiscal 2022, Industrial programs will continue to focus on delivering a variety of initiatives that will help customers achieve energy savings, increase their energy literacy, and make it easier to do business with us. This includes:

- Providing customers with access to energy data information, such as tools, graphs, charts and reports that identify unusual site consumption and changes in operational energy performance;
- Supporting a SEM approach to integrating energy efficiency considerations into ongoing customer business practices and company culture;
- Raising awareness of the opportunities that exist for customers to save on their electricity bill and integrate best practices in their operations;
- Working with the BC Hydro Alliance of Energy Professionals who assist business customers find opportunities to save energy and install energy-efficient products;
- Providing customers with significant support through training, technical expertise and funding to optimize the energy consumption in their operations;
- Support growth in market capability by continuing to support industry-driven efforts by creating the appropriate tools and resources and educational opportunities to deliver sustained, high quality services to the marketplace. These efforts help to drive market transformation; and
- Building relationships with customers centered on energy allowing BC Hydro to further adapt to changing customer needs, and to make informed decisions on potential future programs such as capacity-focused DSM.

3.2 Leaders in Energy Management – Industrial (LEM-I)

3.2.1 Overview

The Leaders in Energy Management – Industrial (LEM-I) program is designed to capture DSM energy savings at industrial facilities by helping customers overcome the financial barriers to energy efficiency. Customers have access to Energy Efficiency Feasibility Study funding to build the business case for electrical efficiency projects. Customers then have access to project incentives to reduce the payback required to make these projects financially feasible if needed.

Sectors covered are large customer segments with common interests and energy opportunities, including Pulp and Paper, Wood Products, Mining, Oil and Gas, Chemical, Cement, Manufacturing, Agriculture, Food and Beverage and Transportation.

The LEM-I program provides business case support to enable the customer to implement facility changes, and benefit from the appropriate rate schedule. Customers can also access capital incentives for upgrades to existing plants or to support efficient plant expansions or new plant designs. When combined with the Industrial Energy Management Activities, a customer can develop a comprehensive plan to continue saving energy at their facility.

Annual Plan	\$M	GWh/yr
F2022	13.7	127
Target Market	Large Industrial (Transmission Service Rate) Customers. Approximately 170 sites. Largest 2,000 Industrial Distribution (General Service Rate) Customers. Approximately 43,000 small industrial customers also have access.	
Key Components	Energy Studies	
	Project Incentives	
	New Plant Design	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	\$9	(\$18)
Benefit Cost Ratios	1.9	2.7

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Bill savings: Reduce customers' electrical operating costs • Remove financial barriers: Incentives to help overcome customers' financial hurdle rates and lower project payback period to an acceptable level • Other non-energy benefits depending on the end-use/project (e.g., maintenance savings, enhanced output/product quality etc.) • Reduce capacity constraints on substation, improving reliability of power and keeping rates low	• Competitiveness: Builds more efficient and competitive industrial facilities in B.C. • Support advancement in technology: Increase market demand advancement of more efficient end uses • Economic: Creates a need for services to support efficiency studies and equipment installations	• Reduces BC Hydro's overall cost of service (lowers the revenue requirement) • Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry to achieve their goals • Retain flexibility: The offer can be adjusted quickly to changing internal and external demands by scaling up or down, adding funding partners or new program measures • Reduce load on capacity constrained substations, improving reliability and deferring costly upgrades

1 3.2.2 Description

	Detailed Description
Energy Studies	Conservation and Energy Management has assembled an external team of North America's top energy efficiency engineers/technologists to investigate and quantify energy efficiency opportunities within our customers' facilities. The LEM-I program offers Energy Efficiency Feasibility Studies to quantify opportunities and build the business case for project implementation.
Project Incentives	Incentives provide additional financial assistance to overcome the affordability barriers that have been impeding projects with longer payback periods.
New Plant Design	The New Plant Design initiative offers industry expertise to provide energy base lining and energy-efficiency design support for new or expanding facilities. These findings are combined with project incentives to encourage efficient designs that surpass industry standards.

2 3.3 Industrial Energy Management Activities

3 3.3.1 Overview

4 The objective of the Industrial Energy Management Activities is to provide
 5 information and tools that assist industrial customers to optimize their energy use.
 6 By encouraging and assisting customers in integrating energy efficiency into their
 7 ongoing business practices and company culture through a SEM approach,
 8 BC Hydro can help to overcome management and business barriers to energy
 9 efficiency and increase the quantity of DSM savings. As a result of these energy
 10 management activities, energy efficiency projects are more likely to come forward
 11 and realize energy savings within the LEM-I program.

12 Industrial Energy Management Activities focus on large customer segments with
 13 common interests and energy opportunities, including Pulp and Paper, Wood
 14 Products, Mining, Oil and Gas, Chemical, Cement, Manufacturing, Food and
 15 Beverage, Agriculture and Transportation.

16 The Industrial Energy Management Activities provide SEM training and resources,
 17 including Industrial Energy Managers. Audits and support are provided to enable the
 18 customer to implement and maintain facility changes, through participation in the
 19 LEM-I program. As part of these activities, Energy Monitoring and Targeting systems

- 1 are implemented at customer sites to understand and use customer energy data to
- 2 improve energy performance and increase operational efficiency. The flexible design
- 3 and the relationships with the customers create a platform for new offers in the
- 4 future such as capacity-focused DSM.

Annual Plan	\$M	GWh/yr
F2022	7.0	n/a
Target Market	Active partnerships with 124 Industrial sites: • 82 sites with the SEM – Industrial Energy Manager offer; • 28 sites with the SEM – Cohort Energy Manager offer; and • 12 sites with the SEM – Regional Energy Manager offer (Transmission Service Rate) Customers. Approximately 170 sites. Largest 2,000 Industrial Distribution (General Service Rate) Customers.	
Key Components	Strategic Energy Management – Industrial Energy Manager	
	Strategic Energy Management – Cohort Energy Manager	
	Strategic Energy Management – Regional Energy Manager	
	Energy Monitoring and Targeting	
	Energy Audits	
	BC Hydro Alliance of Energy Professionals	
	External Workforce Capability Building	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
- Energy management information, advice, and program access support - Improve corporate culture around SEM: A strategic approach by supporting organizations to develop a sustained corporate level strategic energy management program - Assistance in accessing qualified energy management products and industry expertise - Energy Monitoring and Targeting: Access to energy data to improve operational efficiency	- Competitiveness: Builds more efficient and competitive industrial facilities in B.C. - Industry capacity: Support and grow the energy management industry through the BC Hydro Alliance of Energy Professionals - Support advancement in technology: Increase market demand for new, more efficient products and services - Economic: Creates a need for services to support efficiency studies and equipment installations	- Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry achieve their energy management goals - Foundational platform for future offers to this customer segment such as demand response - Support Customer Service: Ability to integrate customer strategy initiatives as necessary to ensure optimized delivery of offers - Retain flexibility: The offer can be adjusted quickly to changing internal and external demands by scaling up or down, adding funding partners or new program measures

1 3.3.2 Description

	Detailed Description
Strategic Energy Management: Industrial Energy Manager	The SEM Industrial Energy Manager offer provides funding to industrial customers to embed strategic energy management practices into their organizations. BC Hydro will provide funding for an Industrial Energy Manager who will receive specialized training and knowledge on developing and implementing an SEM plan. The initiative includes energy assessments to assist customers to gain energy insights, build executive support for energy efficiency and define the energy opportunity and value proposition for their company. Industrial Energy Managers have access to additional funding and resources for Employee Awareness initiatives and enhanced Energy Monitoring and Targeting at their organization. This can drive energy improvements through participation in LEM-I by improving SEM practices at large industrial facilities with increased use of energy intelligence, monitoring and reporting, business processes, and awareness. Fully funded Energy Scans are offered to IEM managed sites to identify further opportunities for energy efficiency, with these opportunities documented and tracked through an Opportunity Register. Industrial Energy Managers also have access to funding to hire an engineering co-op student to support implementation of their SEM program. This offer also supports external workforce capability training.

	Detailed Description
Strategic Energy Management: Cohort	The SEM Cohort Energy Manager offer is intended to build SEM at customer sites that are not large enough to support a dedicated Industrial Energy Manager. We bring together a group of industrial customers to work together and share knowledge related to building energy management in their business. The goal is to translate these insights into changes in daily business operations by using a customer's own energy data to build a facility-wide energy model that will help them to continuously improve their energy performance, and realize savings through participation in LEM-I. Through the systematic use of energy data, operational models are created for small and medium industrial facilities that enable the identification and monitoring of energy improvements.
Strategic Energy Management: Regional Energy Manager	The SEM Regional Energy Manager offer is intended to build SEM at small to medium sized industrial customer sites. Two Regional Energy Managers will help small to medium sized industrial customers to understand SEM and enroll in the Operational Energy Analytics offer. Through Operational Energy Analytics leveraging SMI and MyHydro, the customers will go through an onsite audit and several months of data monitoring that can enable operational savings at their facilities to be realized through participation in LEM-I.
Energy Monitoring and Targeting	Energy Monitoring and Targeting is designed for SEM participants to identify process anomalies or new projects (operational or capital) that result in operational or hard-wired savings. Customers will also be able to quantify/validate savings through the development of an accurate energy monitoring and targeting model and deployment of reporting capability at the facility or subsystem level.
Energy Audits	The Industrial Energy Management activities offer Energy Scans, Plant-Wide Audits and End Use Assessments to identify energy-saving opportunities at industrial facilities. The objective is to provide access to industry experts who can help industrial customers audit facilities and identify energy improvement projects as part of a corporate strategic energy management plan. Opportunities are documented and tracked through an Opportunity Register.
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, distributors and registered experts that will promote the use of energy management and efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to assist our customers within the context of DSM programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. The BC Hydro Alliance of Energy Professionals also enables Conservation and Energy Management to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified.

	Detailed Description
External Workforce Capability Training	A critical success factor for the DSM Plan is that there is an available and accessible “energy efficiency skilled” workforce in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce by partnering with post-secondary institutions and industry associations who develop and deliver new training and educational programs. The objective of education and training is to develop and build market capacity of individuals that will be qualified to become energy managers and energy champions within customer and industry organizations as well as to grow the pool of qualified individuals who can join trade ally firms. This will support program participation, increase awareness and action and ultimately integrate efficiency into ongoing business processes. This initiative includes integrating energy management modules within targeted disciplines of academic and training institutions as well as the development of materials to educate customers and trade allies. This provides support for students enrolled in post-secondary institutions, addressing the adequacy requirements of the Demand-Side Measures Regulation.

4 Capacity-Focused Demand-Side Management

4.1 Overview

Over the past few years, a wide variety of capacity-focused activities have been completed, providing information that informs the savings opportunities and costs of different technologies and approaches. These learnings have been incorporated into the DSM capacity resource options developed for the upcoming Integrated Resource Plan (**IRP**). During this time, capacity-focused activities have also been explored as ‘Non-Wires Alternatives’ that may emerge as viable options to capital projects in constrained substations or feeders.

It is important to maintain capacity-focused DSM activity until the outcome of the IRP is known and work on developing an approach to Non-Wires Alternatives is completed. Planned expenditures in fiscal 2022 are informed by actual performance in fiscal 2020 and fiscal 2021 and will focus on implementing Non Wires Alternatives activities at substations. This will include the use of a Demand Response Management System (**DRMS**) by Transmission and Distribution Systems Operations to trigger control events on customer connected devices and monitor how they lower

- 1 demand on targeted areas. Future levels of expenditures will be based on the
- 2 outcome of the Non-Wires Alternative work and the upcoming IRP.

Annual Plan	\$ million	
F2022	2.9	
Target Market	All sectors	
Key Components	Non-Wires Alternatives	
	DRMS	
	Emerging Technology	
Cost Effectiveness	Utility Cost	Total Resource Cost
Net Levelized Cost (\$/MWh)	n/a	n/a
Benefit Cost Ratios	n/a	n/a

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
- Financial incentives for shifting/curtailing load - Access to new controls or information to better manage energy and demand - Defers or eliminates construction in local communities - Improves local reliability - Supports electrification by helping to mitigate costs (e.g., panel management) - Better understanding of capacity opportunities (which is an area of investigation that customers have desired) - Potential reduction in some demand charges for larger business customers	- Allows industry players to have more comprehensive solutions to provide customers (energy efficiency plus capacity initiatives) - Creates demand for products and services to support project implementation, such as equipment installations	- Potential to defer generation capacity costs - Potential to defer distribution capacity infrastructure costs, or to increase operational flexibility - Integrates approach to jointly manage all aspects of electricity usage - Improves system reliability - Creates demand side flexibility - May facilitate electrification and customer connections to the system by addressing capacity constraints - Contribute to grid of the future

1 **4.2 Description**

	Detailed Description
Non-Wires Alternatives Activities	These activities are forecast to be targeted at five substations. - Each substation will be analyzed based on customer composition and BC Hydro load management needs, therefore a somewhat custom approach is developed for each targeted area. - A package of energy efficiency and demand response activities will be targeted towards the specific loads in the area.
DRMS	Use of a DRMS by the Transmission and Distribution System Operations group to optimize parts of the grid using the flexibility of customer load.
Emerging Technologies	This activity will involve a small amount of monitoring and testing of viable, commercialized technologies that can assist with creating flexible load for BC Hydro.

2 **5 Codes and Standards**

3 **5.1 Overview**

4 To achieve its energy conservation targets and as required by the Demand-Side
 5 Measures Regulation, BC Hydro supports government implementation of new and
 6 updated codes and regulations, which set efficiency requirements in building codes,
 7 product and equipment standards and bylaws. BC Hydro drives and supports energy
 8 efficiency policy, code and standard development by working with the Federal
 9 Government, Government of B.C., key municipal governments and indigenous
 10 communities in B.C. through committees, programs and peer networks. In addition,
 11 the Codes and Standards initiative enables and facilitates implementation of new
 12 regulatory requirements by driving and supporting capability-building initiatives with
 13 partners in government, industry and educational institutions to transform the
 14 marketplace to energy efficient practices and products. These initiatives include
 15 policy or code implementation funding offers, pilot projects, industry training and
 16 education programs, community planning and policy support, and partial funding of
 17 positions within key organizations that support codes and standards development
 18 and implementation.

- 1 Codes and Standards activities target governments (federal, provincial, local),
 2 indigenous communities, the residential and commercial building sectors, as well as
 3 industry, supplier and manufacturing sectors to achieve its market transformation
 4 objective. The positive, long-lasting relationships with stakeholders and successful
 5 deployment of initiatives can be utilized in the future to advance new offers.
 6 Codes and Standards activities are a specified demand-side measure per the
 7 Demand-Side Measures Regulation.

Annual Plan	\$ million	GWh/yr
Fiscal 2022	5.4	259
Key Components	Codes and Standards Investigation, Development & Implementation • Product and Equipment Standards/Regulations • B.C. Building Code (Residential and Commercial) • Energy Step Code • City of Vancouver Building By-law (Residential and Commercial) • Code compliance/enforcement enhancement • Building Energy Benchmarking Labelling • Peer Networks • Community Planning • Community Energy Manager, Building Department & Intern Offers • Project Implementation Offer • Indigenous Communities Policy Support • New Construction Capability Building and Industry Support	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
- Reduced energy bills - Tools, financial and technical support for communities (local governments and Indigenous Communities), as well as commercial Energy Management Activities - More high-performance products, homes, and buildings in the B.C. market	- Policy and Codes roadmaps provide market certainty - Local government support and implementation projects channeled to support market transformation - Collective forum for informing and advising on smooth market transformation - Partnerships, training and support for the building industry to move to more energy efficient design and operational building practices	- Driving market transformation through convening partnership efforts rather than program-based approaches - Cost-effective DSM - Strengthens relationships with local governments and Indigenous Communities. - Relationships with Federal and Provincial governments to advance energy efficiency Codes and Standards

1 5.2 Description

	Detailed Description
Codes and Standards Investigation, Development & Implementation	The initiative seeks to address the availability, awareness, and acceptance barriers that are holding back the development of new energy efficiency codes and standards, and the adoption of more energy efficient building practices and products. Those barriers are reduced by: - Providing technical and financial support to governments and standard developing organizations for the development and identification of comprehensive and effective energy efficiency standards, regulations, codes and other government policy instruments. - Building stakeholder support with other Canadian and U.S. utilities (e.g., in the Pacific Northwest) for changes/updates to codes and standards. - Supporting trade allies and building officials in their compliance with codes and standards via training and education for industry. - Supporting governments in their compliance checking / enforcement of codes and regulations by providing market intelligence on energy-efficient equipment stocking and building construction practices as well as co-funding support for code compliance enhancement efforts with all three levels of government.

	Detailed Description
Peer Networks	A critical element of market transformation is creating networks, maintaining partnerships and driving collective work plans so that partners coordinate the use of their different levers towards the common objectives. • Energy Step Code Council (50+ government, utility and industry organizations) – Capability-Building and Communications Subcommittee – Part 3 Technical Subcommittee – Part 9 Technical Subcommittee – Local Government Peer Network • Community Energy Manager Network – 50+ local governments • We currently support a Building Energy Manager Network, including staff from local government building departments, Building Officials' Association of BC (BOABC), and Provincial Buildings Safety and Standards Branch. In fiscal 2022, we are working to connect the network with: – Builders - through the Local Energy Efficiency Partnerships (LEEP) and Canadian Home Builders Association (CHBA) – Realtors – through the BC Real Estate Association, and – Other Local Government staff networks
Community Planning	Funding for local governments to embed energy considerations in community planning processes. This offer supports community energy and emissions plans, local area plans (neighborhood plans), green building strategies and electric vehicle strategies.
Community Energy Manager, Building Department & Intern Offers	These offers support the addition of resources within local governments to implement work plans that make use of local governments' levers to drive energy efficiency and broader offers at the community scale. Work plan development includes organizational assessment and benchmarking with senior management.
Project Implementation Offer	Funding for local governments to support implementation of efficiency policies and actions at the community scale.

	Detailed Description
Indigenous Communities Policy Support	The Indigenous Communities Policy Support element of the Codes and Standards initiative provides: • Funding for the development and implementation of community energy plans that articulate both short and long-term opportunities and actions for community energy management; • Funding for staff positions at the Band or Tribal Council level to embed knowledge and capability in the community to support the advancement of programs and projects; • Delivery of education and skills training initiatives to build energy literacy in the community, empower community members to manage energy use and reduce energy costs, and foster local economic development opportunities related to energy (e.g., new high-performance housing, energy efficient building upgrades, etc.); and • Funding and technical resources to support the development and implementation of energy efficient building policy so that new buildings on reserve are built to higher energy performance standards (Energy Step Code) and so that existing buildings are upgraded to improve energy performance over time.
New Construction Capability Building and Industry Support	BC Hydro works with builders, developers, design professional associations, energy advisors, realtors, other industry partners, and government to create demand for and construct homes and buildings that are more energy-efficient than the B.C. Building Code minimum requirements. This helps to build awareness and acceptance of the role that step codes can play in transforming the market. Recognizing the need to move beyond influencing individual projects through an incentive strategy, this initiative focuses on activities that leverage deep market changes to transform the residential and commercial new construction industries in four key ways: • Create opportunities for diverse access to builder and industry training and education on energy efficiency standards; • Build consumer awareness on the value of higher performance homes and buildings; • Collaborate with industry professional associations and market players to research and identify suitable high-performance solutions for the B.C. construction industry, support market accessibility and mass market adoption of these solutions; and • Work with local governments to streamline approaches to increase code compliance, policy development, and adoption of the BC Energy Step Code. Funding support is provided to local governments for step code implementation initiatives.

6 Rates

6.1 Residential Inclining Block Rate

BC Hydro introduced its Residential Inclining Block rate structure in October 2008. Customers are charged for electricity consumption at two rates, an initial Step 1 threshold of 1,350 kWh per two-month billing period charges at a lower rate (as of April 1, 2020, 9.35 cents per kWh); and a higher rate for Step 2 consumption above that threshold (as of April 1, 2020, 14.03 cents per kWh). This provides customers with a price signal that encourages conservation.

The most recent Residential Inclining Block Evaluation Report² finds that no new incremental savings are anticipated in future years. However, the current pricing signal continues to encourage customers to maintain previous savings. As shown, no new incremental costs are planned.

Annual Plan	\$ million	GWh/yr
F2022	\$0	0
Target Market	Residential Sector	
Cost Effectiveness	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	n/a	n/a
Benefit Cost Ratios	n/a	n/a

6.2 Rate Schedule (RS) 1823, Stepped Rate

The Stepped Rate, also referred to as the Transmission Service Rate, applies to most large customers that are supplied with electricity at transmission voltages (60,000 volts or more). The rate has been in place since April 2006. There are approximately 145 transmission customer sites taking electricity service under the Transmission Service Rate.

² Evaluation of the Residential Inclining Block Rate F2013-F2017, April 2018.

The Transmission Service Rate is a two-tier (Tier 1 and Tier 2) inclining block conservation rate where annual energy consumption above a threshold is charged at a higher Tier 2 rate and annual energy consumption up to the threshold is charged at a lower Tier 1 rate. The energy consumption threshold is set at 90 per cent of the plant's historical annual energy consumption (called the Customer Baseline). The result is a 90:10 split in energy pricing. This provides customers with a price signal that encourages conservation.

As of April 1, 2020, the Tier 1 price was 4.489 cents per kWh, and Tier 2 was priced at 10.057 cents per kWh. Customers are also charged for electricity demand at a flat rate \$8.609 per kVA based on 30min peak kVA demand during High Load Hours (HLH).

Annual Plan	\$ million	GWh/yr
F2022	0.5	119
Target Market	Industrial transmission customers	
Cost Effectiveness (including NEBs)	Utility Cost (Market Price)	Total Resource Cost (LRMC @ \$54/MWh)
Net Levelized Cost (\$/MWh)	(\$11)	\$26
Benefit Cost Ratios	34.6	1.8

7 Supporting Initiatives

7.1 Public Awareness

7.1.1 Overview

The Public Awareness Supporting Initiative includes a set of foundational activities that build the awareness of ways to increase conservation and energy efficiency and help increase participation in various energy efficiency measures and programs as laid out in the Demand-Side Measures Regulation. The key target audiences for these public awareness activities are current BC Hydro customers and K-12 students – BC Hydro's future customers. Customers' energy literacy and

1 receptiveness to the concept of energy efficiency is elevated as a result of these
 2 supporting activities that are designed to address two specific barriers to
 3 participation: awareness of activities and programs, and the acceptance of those
 4 programs.

5 This increased awareness and acceptance ultimately sets the stage for improved
 6 participation in a variety of behaviours and programs and the support of codes and
 7 standards. These activities cover a variety of channels designed to effectively reach
 8 a wide cross-section of customers and also includes a school's program.

9 **7.1.2 Area of Focus**

Annual Plan	\$ million	GWh/yr
F2022	7.6	n/a
	Public Awareness: communications strategies and campaigns delivered via all channels	
	Public Engagement: face-to-face coaching with customers in communities and at sponsorship events	
	Schools Outreach: energy education programs matched to the B.C. Curriculum and designed to reach the digital classroom.	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
- Builds awareness and understanding of ways to increase energy efficiency - Provides customers one source of information and the knowledge to participate in DSM programs - Educates students about conservation and efficiency and builds customer and student energy literacy	- Supports retailers, distributors, trade allies, engineering/ consulting firms, and manufacturing partners through promotion and awareness of products and programs - Support teachers and the Ministry of Education to reach their goals	- Builds one cohesive story in the marketplace across residential, commercial and industrial programs - Foundational supports for DSM program targets - Program can expand to include new concepts around energy analytics and capacity-focused offers - Builds BC Hydro's reputation and brand as a clean energy company supporting the growth of a conservation culture

1 **7.1.3 Description**

	Detailed Description
Public Awareness	The public awareness strategy and core focus is on the key conservation campaigns through paid media and year-round content through BC Hydro owned/digital channels to sustain the story. By using a combination of paid, owned and earned communications strategies, BC Hydro can reach customers with messages intended to elevate awareness of energy efficiency and encourage residential and business customers to undertake actions. Strategies and messages target a range of demographics including multilingual communications. Efforts place emphasis on digital channels, the development of rich content (e.g., video, animation) and the role of social media in elevating awareness and engagement while maintaining a foothold in traditional channels where media consumption habits are still high (TV, radio). Driving customers to bchydro.com and powersmart.ca for in-depth information about tips and programs is a central part of the strategy, with a growing focus on mobile viewing habits. BC Hydro continues to cultivate a rich network of social media and eNewsletter subscribers who receive content daily and monthly outside of campaign windows. In addition, BC Hydro's media strategy supports conservation year-round through storytelling and sharing data and reports that are newsworthy and create buzz in traditional media channels and beyond to online channels.
Public Engagement	Engaging with customers face-to-face helps build awareness and gain support for energy efficiency activities. A focus on engagement allows for rich conversations and dialogue that spark an interest in conservation leading to action at home and in businesses. This initiative includes business and community outreach targeted primarily at home shows, retail stores, community events and business locations, providing information on energy tips, products, and programs. The team acts as personal energy coaches, delivering custom ideas and support to encourage the adoption of energy efficient products, services and behaviours.

	Detailed Description
Schools Program	The Schools Program entails producing and distributing high quality energy education materials to meet BC curriculum requirements. The goal is to fill the gap for quality digital programming and interactive lesson plans for today's digital classroom. The schools program targets K-12 teachers, students and administrators to foster awareness and build energy literacy in our next generation of customers through comprehensive, curriculum-based teaching materials, initiatives and face-to-face interactions. The program is primarily delivered through an online platform. The program also includes a strategy to capitalize on nation-wide events such as Environmental Week, Earth Day, and Water Week by creating premium materials and resources for teachers at key points throughout the school year. This support for students addresses the adequacy requirements of the Demand-Side Measures Regulation. The support for the post-secondary education component of the Demand-Side Measures Regulation is described within Commercial and Industrial Energy Management Activities.

1 7.2 Indirect Support

2 7.2.1 Overview

3 Running a broad portfolio of programs and initiatives requires additional support
 4 activities that are necessary to successfully design, develop, and implement a
 5 successful portfolio. These are referred to as Deferred Indirect and Portfolio
 6 Enabling activities.

7 These activities support BC Hydro's DSM initiatives with general management and
 8 infrastructure, including DSM planning and regulatory activities and the development
 9 and administration of policy and processes related to the effectiveness and integrity
 10 of DSM initiatives.

Annual Plan	\$ million	GWh/yr
F2022	7.4	n/a
Key Components	General management	
	Information Systems	
	Support and Administration	
	Training and Education	
	Support Services	

1 **7.2.2 Description**

	Detailed Description
General Management	A portion of the Conservation and Energy Management's key business unit's general management of people and resources.
Information Technology Systems	Support, operation and management of DSM information technology systems as well as the planning and management of system enhancements and improved functionality for the tracking and managing of customer activities. DSM information systems include: • Systems/applications to support customer contact management, account views, project tracking, opportunity and sales management; and • Energy Reporting: systems and applications that support the ability to report on energy savings and program participation
Support and Administration	A portion of the Conservation and Energy Management key business unit's general administrative functions including costs associated with administrative activities, photocopy equipment, office supplies, as well as a portion of labour for individual timesheets, expense reporting and benefits administration.
Training and Education	Individual employee training related to DSM, including technical seminars and attendance at conferences.
Support Services	Regulatory activities that support regulatory filings and reporting. The development and updating of DSM strategy and policies, as well as modelling and cost-effectiveness analysis. Support activities related to the development, administration, and review of general processes, policies, and procedures related to the effectiveness and continuous improvement. Examples include measurement and verification protocols, business or financial audits, and quality assurance.

2 **8 Key Program Assumptions**

3 The following table provides the key program assumptions that apply to the energy
 4 savings based on the activities for fiscal 2022. Ranges indicate that there are sub-
 5 components within the initiative that have different adjustment factors. Further
 6 details can be found in Section C Portfolio-Wide Assumptions.

Sector	Program	Compliance Rate (%)	Cross Effects (%)	Direct Rebound Effects (%)	Free Rider (%)	Market Effects (%)	Persistence (years)	Spillover (%)	Non-Install (%)
Cross Sector	Building codes	63 - 98	0	0	n/a	n/a	30	n/a	n/a
	Product & Equipment Standards	75 - 97	0 - 6	0	n/a	n/a	5 - 30	n/a	n/a
	Capacity Focused		n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential	Behaviour		0	0	0	0	1 - 24	0	0
	Home Renovation Rebate		0	0 - 6	0 - 45	0	9 - 30	0 - 44	0
	Low Income		0 - 5.7	0 - 6	0 - 69	0	1 - 30	0 - 17	0 - 70
	Non-Integrated Areas		0 - 5.7	0 - 6	5 - 69	0	1 - 30	0 - 17	0 - 70
	Retail		0 - 5.7	0	10 - 40	0	1 - 20	0 - 10	0 - 20
Commercial	Leaders in Energy Management - Commercial		0 - 11	0	0 - 39	0	1-30	0 - 22	0
	New Construction		0	0	14	0	17	15	0
Industrial	Leaders in Energy Management - Industrial		0	0	0 - 16	0	1 - 15	0 - 13	0

1 *Definitions*

Compliance Rate	The rate at which customers, retail channels, or builder/developers actually meet the established code or standard (knowingly or unknowingly)
Cross Effects	The effect of an energy efficient action on one energy use causing a change in another energy use. For example, more efficient lighting products typically release less waste heat and thereby reduce air-conditioning load
Direct Rebound	The increased usage of a device or system because it is more energy efficient
Free-riders	Customers who participate in a DSM program but who would have undertaken the same change at the same time in the absence of the program
Market Effects	Refers to a change in the structure or functioning of a market or the behaviour of participants in a market that result from one or more program efforts. Typically, these efforts are designed to increase the adoption of energy efficient products, services, or practices and are causally related to market interventions. Market effects may include participant and non-participant spillover and market transformation
Persistence	The timeframe during which DSM measures produce electricity savings that are attributable to the utility's actions
Spillover	Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs additional energy efficiency measures or applies additional energy savings practices after having participated in the efficiency program, as a result of the program's influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence
Non-install	Customers who purchase the energy efficient device but do not install it

Section B: Detailed Financial Tables

Table M-1 Total BC Hydro Costs (\$ million)

	F2022 Plan
Rate Structures	
Residential Inclining Block Rate	0.0
General Service Rate	0.0
Transmission Service Rate	<u>0.5</u>
Total Rate Structures	0.5
DSM Programs	
<u>Residential Sector</u>	
Low Income	7.4
Non Integrated Areas	1.4
Retail	2.2
Home Renovation Rebate	5.0
Residential Energy Management Activities	<u>5.0</u>
<i>Residential Sector Total</i>	<i>21.0</i>
<u>Commercial Sector</u>	
LEM-C	8.6
New Construction	1.9
Commercial Energy Management Activities	<u>6.2</u>
<i>Commercial Sector Total</i>	<i>16.6</i>
<u>Industrial Sector</u>	
LEM-I	13.7
Thermo-Mechanical Pulp	0.0
Industrial Energy Management Activities	<u>7.0</u>
<i>Industrial Sector Total</i>	<i>20.8</i>
Total DSM Programs	58.4
Supporting Initiatives	
Public Awareness	7.6
Indirect and Portfolio Enabling	<u>7.4</u>

	F2022 Plan
Supporting Initiatives Total	15.0
Total DSM Programs, Rates & Supporting Initiatives	73.9
Codes and Standards	5.4
Capacity Focused DSM	2.9
PORTFOLIO TOTAL	82.2

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Table M-2 BC Hydro Incentive Costs (\$ million)

	F2022 Plan
Rate Structures	
Residential Inclining Block Rate	0.0
General Service Rate	0.0
Transmission Service Rate	<u>0.0</u>
Total Rate Structures	0.0
DSM Programs	
<u>Residential Sector</u>	
Low Income	5.0
Non Integrated Areas	0.6
Retail	1.0
Home Renovation Rebate	4.0
Residential Energy Management Activities	<u>0.7</u>
<i>Residential Sector Total</i>	<i>11.2</i>
<u>Commercial Sector</u>	
LEM-C	4.8
New Construction	1.4
Commercial Energy Management Activities	<u>3.4</u>
<i>Commercial Sector Total</i>	<i>9.5</i>
<u>Industrial Sector</u>	
LEM-I	10.4
Thermo-Mechanical Pulp	0.0
Industrial Energy Management Activities	<u>4.6</u>

	F2022 Plan
<i>Industrial Sector Total</i>	<i>15.0</i>
Total DSM Programs	35.7
Supporting Initiatives	
Public Awareness	0.0
Indirect and Portfolio Enabling	<u>0.0</u>
Supporting Initiatives Total	0.0
Total DSM Programs, Rates & Supporting Initiatives	35.7
Codes and Standards	0.0
Capacity Focused DSM	0.9
PORTFOLIO TOTAL	36.6

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Table M-3 BC Hydro Non-Incentive Costs (\$ million)

	F2022 Plan
Rate Structures	
Residential Inclining Block Rate	0.0
General Service Rate	0.0
Transmission Service Rate	<u>0.5</u>
Total Rate Structures	0.5
DSM Programs	
<u><i>Residential Sector</i></u>	
Low Income	2.4
Non Integrated Areas	0.8
Retail	1.2
Home Renovation Rebate	1.0
Residential Energy Management Activities	<u>4.3</u>
<i>Residential Sector Total</i>	<i>9.8</i>
<u><i>Commercial Sector</i></u>	
LEM-C	3.8
New Construction	0.5
Commercial Energy Management Activities	<u>2.8</u>
<i>Commercial Sector Total</i>	<i>7.1</i>
<u><i>Industrial Sector</i></u>	
LEM-I	3.3

	F2022 Plan
Thermo-Mechanical Pulp	0.0
Industrial Energy Management Activities	<u>2.5</u>
<i>Industrial Sector Total</i>	5.8
Total DSM Programs	22.7
Supporting Initiatives	
Public Awareness	7.6
Indirect and Portfolio Enabling	<u>7.4</u>
Supporting Initiatives Total	15.0
Total DSM Programs, Rates & Supporting Initiatives	38.2
Codes and Standards	5.4
Capacity Focused DSM	2.0
PORTFOLIO TOTAL	45.6

1
2

**Table M-4 New Incremental Energy Savings at
Customer Meter (GWh/yr)**

	F2022 Plan
Codes and Standards	
Residential	137
Commercial	115
Industrial	<u>7</u>
Total Codes and Standards	259
Rate Structures	
Residential Inclining Block Rate	0
General Service Rate	0
Transmission Service Rate	<u>119</u>
Total Rate Structures	119
DSM Programs	
<i>Residential Sector</i>	
Low Income	8
Non Integrated Areas	1
Retail	7
Home Renovation Rebate	9

	F2022 Plan
Residential Energy Management Activities	<u>16</u>
<i>Residential Sector Total</i>	41
<u><i>Commercial Sector</i></u>	
LEM-C	37
New Construction	6
Commercial Energy Management Activities ¹	<u>n/a</u>
<i>Commercial Sector Total</i>	43
<u><i>Industrial Sector</i></u>	
LEM-I	127
Thermo-Mechanical Pulp	0
Industrial Energy Management Activities ¹	<u>n/a</u>
<i>Industrial Sector Total</i>	127
Total DSM Programs	210
PORTFOLIO TOTAL	588

- 1 ¹ Energy management activities enable and support the energy savings captured under other programs in the
2 commercial and industrial sectors.

3 **Table M-5 New Incremental Capacity Savings at**
4 **Customer Meter (MW)**

	F2022 Plan
Codes and Standards	
Residential	35
Commercial	16
Industrial	<u>1</u>
Total Codes and Standards	51
Rate Structures	
Residential Inclining Block Rate	0
General Service Rate	0
Transmission Service Rate	<u>9</u>

	F2022 Plan
Total Rate Structures	9
DSM Programs	
<u>Residential Sector</u>	
Low Income	2
Non Integrated Areas	0
Retail	2
Home Renovation Rebate	3
Residential Energy Management Activities	<u>3</u>
<i>Residential Sector Total</i>	<i>11</i>
<u>Commercial Sector</u>	
LEM-C	6
New Construction	1
Commercial Energy Management Activities ¹	<u>n/a</u>
<i>Commercial Sector Total</i>	<i>6</i>
<u>Industrial Sector</u>	
LEM-I	15
Thermo-Mechanical Pulp	0
Industrial Energy Management Activities ¹	<u>n/a</u>
<i>Industrial Sector Total</i>	<i>15</i>
Total DSM Programs	33
PORTFOLIO TOTAL	93

- 1 ¹ Energy management activities enable and support the capacity savings captured under other programs in the commercial and industrial sectors.
- 2

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Table M-6 Benefit Cost Ratios¹

	LRMC \$54/MWh (\$F2019)		Market Price
	Total Resource Cost Test including NEBs	Total Resource Cost Test excluding NEBs	Utility Cost Test
Rate Structures			
Residential Inclining Block Rate	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a
Transmission Service Rate	<u>1.8</u>	<u>1.8</u>	<u>34.6</u>
Total Rate Structures	1.8	1.8	34.6
DSM Programs			
<u>Residential Sector</u>			
Low Income ²	2.6	2.6	1.2
Non Integrated Areas ³	2.4	2.4	1.7
Retail	2.6	2.5	3.2
Home Renovation Rebate	<u>1.5</u>	<u>1.4</u>	<u>3.4</u>
<i>Residential Sector Total</i>	<i>1.9</i>	<i>1.8</i>	<i>2.2</i>
<u>Commercial Sector</u>			
LEM-C	3.0	1.5	2.2
New Construction	<u>1.6</u>	<u>1.2</u>	<u>2.6</u>
<i>Commercial Sector Total</i>	<i>2.6</i>	<i>1.4</i>	<i>2.3</i>
<u>Industrial Sector</u>			
LEM-I	2.7	1.7	1.9
Thermo-Mechanical Pulp	<u>n/a</u>	<u>n/a</u>	<u>n/a</u>
<i>Industrial Sector Total</i>	<i>2.7</i>	<i>1.7</i>	<i>1.9</i>
Total DSM Programs	2.4	1.7	2.1
Energy Management Activities	n/a	n/a	n/a
Supporting Initiatives	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a
PORTFOLIO TOTAL⁴	1.6	1.2	1.4

Notes:

- ¹ Benefit Cost Ratios are based on expenditures and energy savings from activities in fiscal 2022, including persistence.
- ² The Total Resource Cost Test benefit cost ratios for the Low Income, Non-Integrated Areas and Social Housing Retrofit Programs include a 40 percent adder to program benefits in accordance with the DSM Regulation.
- ³ Long Run Marginal Cost (LRMC) is based on NIA generation costs.
- ⁴ Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations.

1

Table M-7 Levelized Costs (\$/MWh)¹

	Gross Levelized Costs		Non-Electricity Benefits		Natural Gas Benefits		Capacity Benefits (Generation)		Capacity Benefits (Transmission and Distribution)		Net Levelized Costs	
	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test
Rate Structures												
Residential Inclining Block Rate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transmission Service Rate	\$38	\$1	\$0	\$0	\$0	\$0	-\$7	-\$7	-\$5	-\$5	\$26	-\$11
Total Rate Structures	\$38	\$1	\$0	\$0	\$0	\$0	-\$7	-\$7	-\$5	-\$5	\$26	-\$11
DSM Programs												
<u>Residential Sector</u>												
Low Income	\$57	\$70	-\$42	\$0	\$2	\$0	-\$27	-\$27	-\$22	-\$22	-\$32	\$21
Non Integrated Areas	\$169	\$168	-\$116	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$53	\$168
Retail	\$42	\$26	-\$1	\$0	\$2	\$0	-\$26	-\$26	-\$23	-\$23	-\$7	-\$23
Home Renovation Rebate	\$101	\$31	-\$11	\$0	-\$12	\$0	-\$38	-\$38	-\$28	-\$28	\$12	-\$34
Residential Sector Total	\$76	\$45	-\$20	\$0	-\$4	\$0	-\$31	-\$31	-\$24	-\$24	-\$4	-\$11
<u>Commercial Sector</u>												
LEM-C	\$49	\$26	-\$73	\$0	\$7	\$0	-\$12	-\$12	-\$11	-\$11	-\$40	\$2
New Construction	\$76	\$23	-\$28	\$0	-\$12	\$0	-\$14	-\$14	-\$11	-\$11	\$11	-\$2
Commercial Sector Total	\$55	\$25	-\$64	\$0	\$3	\$0	-\$12	-\$12	-\$11	-\$11	-\$30	\$2
<u>Industrial Sector</u>												
LEM-I	\$42	\$25	-\$44	\$0	\$0	\$0	-\$8	-\$8	-\$8	-\$8	-\$18	\$9
Thermo-Mechanical Pulp	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Sector Total	\$42	\$25	-\$44	\$0	\$0	\$0	-\$8	-\$8	-\$8	-\$8	-\$18	\$9
Total Programs	\$55	\$30	-\$44	\$0	\$0	\$0	-\$16	-\$16	-\$13	-\$13	-\$18	\$1
Energy Management Activities	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Supporting Initiatives	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
PORTFOLIO TOTAL²	\$72	\$44	-\$33	\$0	\$0	\$0	-\$14	-\$14	-\$12	-\$12	\$14	\$19

- 2 Notes:
- 3 1 Levelized costs are based on expenditures and energy savings from activities in fiscal 2022, including persistence.
- 4 2 Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not
- 5 included in cost-effectiveness calculations.

1 Section C: Portfolio-Wide Assumptions

Inflation	2.0 per cent.
Discount Rates	5 per cent nominal and 2.9 per cent real, representing BC Hydro's corporate discount rates.
Avoided Costs	<i>Electric energy:</i> LRMC: \$54 per MWh (F2019\$); based on a preliminary cost assessment of B.C. wind energy. This is a conservative estimate until new LRMCs are adopted. <i>Electricity energy (Non-Integrated Area):</i> Equivalent Avoided Cost of Diesel: \$300 per MWh (F2021\$) <i>Market price of electricity:</i> used as an additional filter for the Utility Cost test BC Hydro's forecast of market sell prices at the B.C.-U.S. border, has an average value of approximately \$33/MWh (F2021\$) over a 15-year period from F2021 to F2035. <i>Generation capacity Reference Price:</i> F2021-F2022: \$0 per kW-year F2023-F2031: \$58 per kW-year (F2016\$) F2032 onwards: \$118 per kW-year (F2016\$) <i>NIA capacity Price:</i> nil Representing BC Hydro's current long-run marginal cost generation capacity price. <i>Bulk transmission capacity:</i> \$0 per kW-year (F2011\$) because there are no bulk transmission capacity investments expected to be deferred by demand-side management initiatives. <i>Regional transmission and substation capacity:</i> \$50 per kW-year (F2019\$), based on BC Hydro estimates of the regional transmission and substation capacity costs avoided by demand-side management initiatives. <i>Distribution capacity:</i> \$25 per kW-year (F2019\$), based on BC Hydro estimates of the distribution capacity costs avoided by demand-side management initiatives. <i>Natural gas for the Standard Total Resource Cost Test:</i> BC Hydro's forecast of wholesale natural gas prices at Sumas. <i>Natural gas for the Modified Total Resource Cost Test:</i> 100% of the long-run marginal cost of electricity, converted to GJ.
Generation System Reserve Margin	14% in times of generation capacity deficit 0% in times of generation capacity surplus

Rates	The following BC Hydro rates were used to calculate customer bill savings and lost revenues: • Residential Inclining Block; • Small General Service; • Medium General Service; • Large General Service; and • Transmission Service.
Line Losses	Avoided electric energy and generation capacity costs are valued at the Lower Mainland, while avoided transmission and distribution capacity costs are valued in the regions. This requires an adjustment for line losses between customers and these points in the grid using the following values: • Distribution: 4%; • Intra-regional transmission: 3%; and • Inter-regional transmission: region-specific values. NIA: nil

**BC Hydro Fiscal 2022
Revenue Requirements Application**

Appendix N

Low Carbon Electrification Program

PUBLIC

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1 Overview

The Low Carbon Electrification (**LCE**) Projects/Programs that BC Hydro plans to undertake in fiscal 2022 are described in this Appendix N. The fiscal 2022 plan will be a continuation of activities described in the Previous Application. All of our LCE Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the *Clean Energy Act*. The BCUC, in its Decision on the Previous Application, accepted BC Hydro's request to defer LCE expenditures to the DSM Regulatory Account. A broader electrification plan is under development and will be reflected in future regulatory applications beyond fiscal 2022, as appropriate.

1.1 Greenhouse Gas Reduction Regulation

Section 18 of the *Clean Energy Act* requires the British Columbia Utilities Commission (**BCUC**) to allow BC Hydro to collect sufficient revenue to recover costs incurred for prescribed undertakings. Chapter 2 provides further information on section 18 and the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012 (**GGRR**). Section 4 of the GGRR defines eight classes of electrification prescribed undertakings corresponding to sections 4(2), 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c), 4(3)(d) and 4(3)(e). Activities under subsections 4(3)(a) or 4(3)(b) of the GGRR are prescribed undertakings if they satisfy a cost-effectiveness test defined in subsection 4(1) of the GGRR.

The eight classes of electrification undertakings prescribed by section 4 of the GGRR can be divided into two broad categories: those that are program based, similar to BC Hydro's demand-side management programs,¹ and those that are infrastructure project based.² BC Hydro refers to its undertakings that fall within one

¹ Being the classes of undertaking prescribed by subsections 4(3)(a)(i); 4(3)(a)(ii); 4(3)(b)(i); 4(3)(b)(ii); 4(3)(c) and 4(3)(d) of the GGRR.

² Being the classes of undertaking prescribed by subsections 4(2) and 4(3)(e) of the GGRR.

of the classes in the former category as LCE Projects/Programs, and to its undertakings that fall within one of the classes in the latter category as LCE Infrastructure Projects. The LCE Projects/Programs further consists of two broad categories: LCE Projects (or Initial LCE Projects) and LCE Programs (or BC Hydro LCE Programs), which will be further discussed below.

1.2 Scope of Appendix N

Appendix N describes only LCE Projects/Programs that are in one or more classes of undertakings defined in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR.

In section [2](#) below, BC Hydro provides details for some initial LCE Projects, which were first introduced in BC Hydro's Fiscal 2018 Greenhouse Gas Reduction Regulation Annual Report and described in the Previous Application. For the purpose of this document, these are referred to as "Initial LCE Projects". Section [2](#) also provides planned expenditures, energy impacts and associated capacity impacts for these projects for the test period.

In section [3](#) BC Hydro provides details on BC Hydro's LCE Program which was introduced in fiscal 2019 and described in the Previous Application. For the purpose of this document, this is referred to as the "BC Hydro LCE Program". Section [3](#) also provides planned expenditures, energy impacts and associated capacity impacts for the test period.

In section [4](#) demonstrates the cost-effectiveness of BC Hydro's LCE Projects/Programs that are in the classes of undertakings under section 4(3)(a) and 4(3)(b) of the GGRR.

1.3 Overview of LCE Projects/Programs

Beginning in fiscal 2018, BC Hydro moved forward with the Initial LCE Projects to assess and support immediate low carbon electrification opportunities among our

1 customers. These projects were within one (or more) class of undertakings defined
2 in subsections 4(3)(a) and 4(3)(c). These Initial LCE Projects also:

- 3 • Helped us gain a greater understanding of the technology, market, and barriers
4 that customers and BC Hydro would face when developing low carbon
5 electrification options; and
- 6 • Provided BC Hydro the ability to act early and capture time-sensitive
7 opportunities that could help inform the development of a broader low carbon
8 electrification plan.

9 The Initial LCE Projects were first introduced in the Fiscal 2018 Greenhouse Gas
10 Reduction Regulation Annual Report, and further described in subsequent annual
11 reports and in the Previous Application. In section [2](#) and [Table N-1](#) and [Table N-4](#)
12 below, BC Hydro provides further information on the Initial LCE Projects for which
13 we plan to incur expenditures in fiscal 2022.

14 In early fiscal 2019, the Government of B.C. launched the EfficiencyBC program
15 (which is now branded as CleanBC Better Homes for residential programs and
16 CleanBC Better Buildings for commercial buildings) to reduce greenhouse gas
17 emissions in the province. This Government of B.C. funded program provides
18 financial incentives to help households and businesses save energy and reduce
19 greenhouse gas emissions by switching to high-efficiency heating equipment and
20 making building-envelope improvements. In fiscal 2020, the Government of B.C.,
21 working with BC Hydro, launched a Commercial New Construction offer as part of its
22 CleanBC program. BC Hydro is delivering the fuel switching (from fossil fuel to
23 electricity) component of the CleanBC programs on behalf of the Government of
24 B.C., within BC Hydro's service territory. Also in fiscal 2020, BC Hydro became
25 responsible for delivering the CleanBC 'Go Electric BC' electric vehicle charger
26 rebate program on behalf of the Government of B.C. The program provides rebates
27 toward the cost of the purchase and installation of eligible level two electric vehicle

1 charging equipment and supports multi-unit residential buildings (**MURB**) and
2 workplaces seeking solutions for their electric vehicle charging needs. In fiscal 2021,
3 BC Hydro became responsible for delivering new offers on behalf of the Government
4 of B.C.: CleanBC Commercial Express, which is a prescriptive program targeting
5 simpler electrification opportunities in small and medium-sized businesses; and the
6 CleanBC Better Homes New Construction Program, which provides rebates for the
7 construction of new, high-performance, electrically heated homes. Fiscal 2022
8 expenditures associated with implementing the CleanBC programs are borne by the
9 Government of B.C. and not by BC Hydro ratepayers.

10 In addition to the delivery of components of the CleanBC program, and further to the
11 Initial LCE Projects, in fiscal 2019 BC Hydro launched the BC Hydro LCE Program.
12 The program has been designed to align with and complement greenhouse gas
13 emissions reduction programs funded by the Government of B.C. Should the
14 Government of B.C. bring forward additional programs in the future that would
15 overlap with activities planned or underway with funding from BC Hydro, we can
16 make adjustments to our plans to ensure that any overlap is necessary and by
17 design.

18 In fiscal 2022, BC Hydro plans to continue with the BC Hydro LCE Program activities
19 described in the Previous Application, which consist of components that are within
20 one or more class of undertakings defined by subsections 4(3)(a), 4(3)(b), 4(3)(c),
21 and 4(3)(d) of the GGRR. Expenditures for fiscal 2022 are described in section [3](#)
22 and [Table N-3](#) below. As shown in [Table N-4](#), the undertakings in the classes under
23 section 4(3)(a) and 4(3)(b) of the GGRR are cost-effective.

2 BC Hydro Funded Initial Low Carbon Electrification Projects

The Previous Application described eleven Initial LCE projects, of which 10 have been completed or are planned to be completed by the end of fiscal 2021³. The implementation of the one remaining Initial LCE Project will continue in fiscal 2022 and continues to be a prescribed undertaking under subsection 4(3)(a)(ii). This remaining Initial LCE Project was described in the Previous Application, and the nature and scope of the project has not changed. Further details are provided below.

Customer Project 1 [REDACTED] – [REDACTED]: BC Hydro provided funds to [REDACTED] to assist in the acquisition, installation, and use of equipment that uses electricity to power natural gas production, instead of the customer burning their own gas to power gathering, transport and processing operations. Customer Project 1 has multiple phases, with the first phases either achieving Facility Commercial Operation Date (**COD**) in previous fiscal years or planning to achieve Facility COD in fiscal 2021. The final phases of the project are expected to achieve Facility COD in fiscal 2022. While we plan for these final phases to complete as described, the COVID-19 pandemic has impacted the project, and it is possible that the timing of completion of the final phases of this project may shift.

[Table N-1](#) shows planned expenditures, energy impacts and associated capacity impacts for Customer Project 1.

³ Of the projects planned to complete in fiscal 2021, it is possible that the timing of completion may shift as a result of COVID-19.

Table N-1 Expenditures and New Incremental Load and Capacity Growth for Initial LCE Projects

Initial LCE Projects	2022 Plan			
	Project	Expenditures (\$ million)	New Incremental Load Growth (GWh/yr)	New Incremental Associated Capacity Growth (MW)
4(3)(a)	Project 1	6.00	119.1	16.0

3 BC Hydro LCE Program

As described in section [1.3](#) above, BC Hydro launched the BC Hydro LCE Program in fiscal 2019. The BC Hydro LCE Program focuses on opportunities in industrial process, transportation, and supporting the development of standards that enable the use of electricity instead of other sources of energy that produce more greenhouse gas emissions. Expenditures related to the BC Hydro LCE Program in fiscal 2022 reflect a continuation of the activities described in the Previous Application and include components in one (or more) class of undertakings defined in subsections 4(3)(a), 4(3)(b) and 4(3)(d). [Table N-2](#) below provides an overview of the components of the BC Hydro LCE Program and the corresponding subsection(s) of the GGRR.

Table N-2 Component Description of the BC Hydro LCE Program

Components	Detailed Description	GGRR Subsection
Energy Management Studies and Incentives	Studies and Assessments – BC Hydro provides funding toward studies and assessments to assist customers, or those who may become customers, to identify and develop project opportunities involving the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Project Incentives - BC Hydro provides project incentive funding to reduce the cost of projects to assist customers, or those who may become customers, with the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Funding is provided direct to customers or in some cases direct to persons who: • Design, manufacture, sell, install or in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity, • Design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in building or facilities, or • Design, construct or manage district energy systems.	4(3)(a), 4(3)(b)
Standards Enabler	BC Hydro works with standards making bodies such as various levels of government, who are responsible for land use, building codes, product and equipment standards, policies, bylaws, and community plans, to advance standards for technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions.	4(3)(d)

We expect the COVID-19 pandemic to have minimal impact on planned activities for the BC Hydro LCE Program in fiscal 2022. Being at the early stages of our BC Hydro LCE Program, we are supporting the identification and investigation of LCE opportunities that will in turn lead to implementation in future years. We are seeing strong interest from customers and support from our trade alliance network in advancing energy management study activities. In addition to studies, we also plan to provide project incentive funding in fiscal 2022 to help customers install equipment that uses electricity instead of other sources of energy that produce more

greenhouse gas emissions. We expect projects planned for fiscal 2022 to complete on time. However, the situation continues to evolve and there is a risk that projects may shift in timing due to influences of the COVID-19 pandemic.

[Table N-3](#) below outlines planned expenditures for the BC Hydro LCE Program components in fiscal 2022, as well as energy and associated capacity impacts.

Table N-3 BC Hydro LCE Program Expenditures

BC Hydro LCE Program		F2022 Plan		
GGRR Regulation Subsection	Program Component	Expenditures (\$ million)	New Incremental Load Growth (GWh/yr)	New Incremental Associated Capacity Growth (MW)
4(3)(a), 4(3)(b)	Energy Management Studies and Incentives ⁴	8.61	29.2	10.1
4(3)(d)	Standards Enabler	0.91	n/a	n/a
Program Total		9.52	29.2	10.1

4 Cost Effectiveness

As shown in [Table N-1](#) and [Table N-3](#) included in section 2 and section 3, respectively, BC Hydro has chosen to engage in undertakings that are within one (or more) class of undertakings defined in sections 4(3)(a), 4(3)(b), 4(3)(c) or 4(3)(d) of the GGRR. Undertakings under section 4(3)(a) or 4(3)(b) of the GGRR are prescribed undertakings if they meet the cost-effectiveness test. The cost-effectiveness test requires that each undertaking that is an undertaking within the class of undertakings defined in subsections 4(3)(a) or 4(3)(b) of the GGRR have a positive net present value (**NPV**), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) or 4(3)(b) of the GGRR. Specifically, benefits mean all revenues BC Hydro expects to earn as a result of implementing LCE projects/programs falling

⁴ Labour for the BC Hydro LCE Program is included within the expenditure shown for Energy Management Studies and Incentives.

1 under subsections 4(3)(a) or 4(3)(b), less revenues that BC Hydro expects to earn
2 from the sale of that electricity to export markets. Costs mean all the costs BC Hydro
3 expects to incur to implement LCE projects/programs falling under
4 subsections 4(3)(a) or 4(3)(b), including development and administration costs.
5 Furthermore, the GGRR cost-effectiveness test is measured only at the time
6 BC Hydro decides to carry out the undertaking. There is no other cost-effectiveness
7 test applicable to prescribed undertakings.

8 The [Table N-4](#) below shows the NPV of BC Hydro's prescribed undertaking
9 projects/programs under section 4(3)(a) or 4(3)(b) of the GGRR, for which a decision
10 has been made to carry out the undertaking. The NPV of \$118.8 million indicates
11 that the undertakings within the classes defined in section 4(3) (a) or (b) of the
12 GGRR are cost-effective. BC Hydro interprets "the time the public utility decides to
13 carry out the undertaking" as the time the expenditures associated with an
14 undertaking within a class of undertakings under section 4(3)(a) or 4(3)(b) are
15 internally approved by individuals with the required financial signing authority based
16 on BC Hydro's Financial Approval Authority Policy. This is consistent with
17 BC Hydro's previous practice. Planned expenditures for the BC Hydro LCE Program
18 for fiscal 2022 represent a forecast as of August 2020 and include some
19 expenditures which are forecast but have not yet completed the approval process.
20 As such, those expenditures are not included in the Cost-Effectiveness table. It is
21 expected that including these expenditures, and their associated benefits, in
22 [Table N-4](#) would result in an improvement to the net present NPV.

1 **Table N-4 Cost Effectiveness**

A	B	C	D	E		F		G	
				Additional Energy Consumption (MWh/year)		Additional Demand (MW)		Estimated GHG Emission Reductions (tonnes CO2e/year)	
	Project/ Program/ Contract/ Expenditure	Expenditure (\$ million)	Cost Effectiveness (F18 \$million)	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
		Total	GRR NPV to 2030 (F2031)						
4(3)(a)	Project 1	16.20	64.32	268,056	268,056	36.0	36.0	160,274	160,274
4(3)(a)	Project 2 ⁵	13.50	110.20	223,380	491,436	30.0	66.0	133,562	293,836
4(3)(a)	Project 3 ⁵	0.28	110.47	2,737	494,173	0.0	66.0	562	294,398
4(3)(a) or (b)	BC Hydro LCE Program ⁶	15.60	118.77	65,824	559,996	14.9	80.9	36,301	330,699
	Total	45.58	118.77	559,996	559,996	80.9	80.9	330,699	330,699

2

⁵ Projects 2 and 3 were completed prior to fiscal 2022, and therefore not included in the tables in section 2. The NPV calculation is based on all prescribed undertakings defined in sections 4(3)(a) and 4(3)(b) of the GRR.

⁶ Includes BC Hydro LCE Program costs and benefits related to the class of undertakings defined in sections 4(3)(a) and 4(3)(b) of the GRR only.

-
- 1 One of the legal consequences of BC Hydro's program or project being in a class of
2 prescribed undertakings under section 18 of the *Clean Energy Act* is that BC Hydro
3 is entitled to recover the costs of our electrification programs or projects in rates. The
4 expenditures BC Hydro incurs in regard to its LCE Projects/Programs are sought to
5 be deferred to the DSM Regulatory Account in this application.

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix O Performance Metrics

Integrated Planning

Metrics	F22 Targets
Safety	
• Zero Fatality and Serious Disabling Injury (#) - Employees	0
• Lost Time Injury Frequency	0.28
• Timely Completion of Corrective Actions (%)	97%
• Lost Time Injury (#) - Employees and Contractors	2
Financial	
• O&M (\$M)	\$352.2
• Revenue - Interconnections (\$k)	\$2,330.0
• Revenue - Shared Assets and Leases (\$k)	\$10,943.0
Compliance	
• Mandatory Reliability Standards – Violation Reduction Against F21 (%)	20%
• Timely Completion of Mandatory Reliability Standards' Corrective Actions (%)	95%
• P1 Asbestos Actions >90 Days to Complete (#)	0
• PCB Phase Out Progress (# of Units of Electrical Equipment - Excluding Streetlights)	1,714
People	
• Headcount Equivalent (HCE) - Active Employees Only (#)	962.7
• Training Hours (Excluding Safety Training) per HCE (Hours)	22.0
• Engineering Utilization Rate (Based on Regular Hours) (%)	76.1%
Operational / Service Delivery	
• SAIDI (System Average Interruption Duration Index)	3.20
• SAIFI (System Average Interruption Frequency Index)	1.40
• 5-Year Rolling Average Forced Outage Factor (FOF) Performance (Key Generating Stations) (%)	1.80%
• Capital Delivery Management	
o Enterprise Capital Project Write-Offs (For Deferral) (\$M)	\$10.0
o Ex-Plan Projects (\$M)	Info Only
o Ex-Plan Projects (#)	Info Only
o Integrated Planning Project O&M (\$M)	\$11.3
o Variance Between Power System Capital Expenditure Forecast and Plan in F22 RRA Test Period (%)	± 7.5%
• Customer Interconnections	
o # / MW of Interconnection Requests Received	Info Only
o # / MW of Interconnection Projects Going into Service	Info Only
o Studies Completed On Time (All Types) (%)	80%
• Load Forecast (GWh)	
o Residential Energy (Temp. Normalized GWh)	18,856 - 19,260
o Light Industrial & Commercial Energy	17,014 - 19,314
o Large Industrial Energy	8,310 - 17,537
o Total Domestic Energy for Above Three Sectors	44,180 - 56,111

Capital Infrastructure Project Delivery

Metrics	F22 Targets
Safety	
• Zero Fatality & Serious Disabling Injury (#) - Employees	0
• Lost Time Injury Frequency	0.19
• Timely Completion of Corrective Actions (%)	97%
• Lost Time Injury (#) - Employees and Contractors	5
• Medical Attention - Treatment (#) - Employees and Contractors	10
• Near Misses (#) - Employees & Contractors	325
• Good Catches (#) - Employees & Contractors	325
• Safe Work Observations (#)	3,050
Financial	
• Operating Costs Before Capital Overhead (\$M)	\$84.3
• Capital Delivery Spend (\$M)	\$761.8
Compliance	
• Mandatory Reliability Standards – Violation Reduction Against F21 (%)	20%
• Priority Environmental Incidents (#) - BC Hydro	≤ 14
• # of Project Delivery Projects with PCB Removal (of last piece of equipment containing ≥43ppm PCB) at risk of meeting Federal deadline of December 31, 2025	0
People	
• Headcount Equivalent (HCE) - Active Employees Only (#)	706.9
• Training Hours (excluding safety training) per HCE (Hours)	24
Operational / Service Delivery	
• Project Budget to Actual Cost: Cumulative 5-years (± 5%)	Within ± 5% of budget excl. project reserve amounts
• Performance Against First Full Funding Cost: Projects ≤ Target (% and #)	50%
• Performance Against First Full Funding Schedule: Projects ≤ Target (% and #)	50%
• Capital Additions All Capital Infrastructure Project Delivery (\$M)	\$602.6
• Indigenous Procurement: Contracts Committed (\$M)	Info Only

Operations

Metrics	F22 Targets
Safety	
• Zero Fatality & Serious Disabling Injury (#) - Employees	0
• Lost Time Injury Frequency	1.39
• Timely Completion of Corrective Actions (%)	97%
• Lost Time Injury (#) - Employees	28
• Medical Attention – Treatment (#) - Employees	34
• Lost Time Injuries and Medical Attention – Treatment (#) - Contractors	Info Only
Financial	
• O&M (\$M)	\$261.4
• Total Capital Delivered by Operations (\$M)	\$723.3
• Total Capital Delivered by Program and Contract Management (\$M)	\$437.8
• Total Maintenance Delivered by Operations (\$M)	\$208.8
• Total Maintenance Delivered by Program and Contract Management (\$M)	\$201.7
Compliance	
• Mandatory Reliability Standards – Violation Reduction Against F21 (%)	20%
• Timely Completion of Mandatory Reliability Standards' Corrective Actions (%)	95%
• Priority Environmental Incidents (#)	≤ 6
People	
• Headcount Equivalent (HCE) - Active employees only (#)	2,538.9
• Training Hours (excluding safety training) per HCE (Hours)	45.0
Operational / Service Delivery	
• SAIDI (System Average Interruption Duration Index)	3.20
• SAIFI (System Average Interruption Frequency Index)	1.40
• 5-Year Rolling Average Forced Outage Factor (FOF) Performance (Key Generating Stations) (%)	1.80%
• Connect Time Met - Express Connect (% met in 10 Days)	85%
• Estimated Time of Restoration (ETR) Compliance (%)	75%
• Estimated Time of Restoration (ETR) Accuracy (% within 60 minutes)	80%
• Clean Energy (%)	93%

Safety and Compliance

Metrics	F22 Targets
Safety	
• Zero Fatality and Serious Disabling Injury (#) - Employees	0
• Lost Time Injury Frequency	0.29
• Timely Completion of Corrective Actions (%)	97%
Financial	
• OMA (\$M)	\$68.3
• Capital (\$M)	\$3.7
Compliance	
• Mandatory Reliability Standards – Violation Reduction Against F21 (%)	20%
• Mandatory Reliability Standards – Timely Violation Submissions Within <90 days (%)	95%
• Timely Completion of Mandatory Reliability Standards' Corrective Actions (%)	95%
• WorkSafeBC Incident Full Investigation Deadlines Met (30 Day Deadline) (%)	98%
People	
• Headcount Equivalent (HCE) - Active employees only (#)	382
• Training Hours (excluding safety training) per HCE (Hours)	15.0
• Mandatory Reliability Standards Compliance Training Completion Against Mitigation Plan (%)	95%
Operational / Service Delivery	
• Formal Verifications Completed by Safety & Compliance to Plan (#)	600
• Safe Work Observations Completed by Field Safety Services to Plan (#)	500
• Safety Regulatory Compliance Checks Completed (#)	400
• Safe Work Observations Completed by Safety Advocates to Plan (#)	400
• Safety Advocates Compliance Checks Completed to Plan (%)	90%
• Safety Framework Implementation Milestones per Plan (%)	95%
• Safety Assurance Process Implementation Milestones per Plan (%)	95%
• Assurance Reviews of Emergency Management Plans Completed to Plan (%)	90%
• Physical Security Assurance Activity Corrective Actions Completed / Identified (%)	95%
• Mandatory Reliability Standards Physical Security Preventative Actions & Lessons Learned Communicated to Plan (%)	95%
• Critical Infrastructure Protection (CIP)-006 Mitigation Activities Completed on Time (%)	95%

Finance, Technology and Supply Chain

Metrics	F22 Targets
Safety	
• Zero Fatality & Serious Disabling Injury (#) - Employees	0
• Lost Time Injury Frequency	0.99
• Timely Completion of Corrective Actions (%)	97%
• Lost Time Injury (#) - Employees	7
• Medical Attention – Treatment (#) - Employees	9
Financial	
• O&M (\$M)	\$299.1
• Capital (\$M)	\$103.5
Compliance	
• Mandatory Reliability Standards – Violation Reduction Against F21 (%)	20%
• Timely Completion of Mandatory Reliability Standards' Corrective Actions (%)	95%
People	
• Headcount Equivalent (HCE) - Active Employees Only (#)	953
• Training Hours (Excluding Safety Training) per HCE (Hours)	18
Operational / Service Delivery	
• Technology - Number of Critical Priority Incidents (#)	4
• Technology - Business Impact Due to Critical and High Priority Incidents (Hours)	600
• Technology - Project Delivery - % Business Requirements Met for Closed Projects (YTD Reported Quarterly) (%)	90%
• Technology - Project Implementation Cost Met - % Closed Projects Within Budget (YTD Reported Quarterly) (%)	80%

People, Customer and Corporate Affairs

Metrics	F22 Targets
Safety	
• Zero Fatality and Serious Disabling Injury (#) - Employees	0
• Lost Time Injury Frequency	0.16
• Timely Completion of Corrective Actions (%)	97%
• Lost Time Injury (#) - Employees	1
• Monthly Review of Safe Work Observations (#)	12
Financial	
• OMA (\$M)	\$122.3
• PCCA Full Time Equivalents (#)	858
• Demand Side Management (DSM) Program Spend (\$M)	\$82.2
• Low Carbon Electrification (LCE) Program Spend (\$M)	\$15.5
Compliance	
• Mandatory Reliability Standards – Violation Reduction Against F21 (%)	N/A (0 violations in F21)
People	
• Headcount Equivalent (HCE) - Active Employees Only (#)	858
• Training Hours (Excluding Safety Training) per HCE (Hours)	20
Operational / Service Delivery	
• BC Hydro Retirements (#)	196
• BC Hydro Resignations (#)	127
• BC Hydro Leaders Who Participated in Inclusive Leadership at BCH Training in F22 (%)	30%
• Communications: Favourable Attitude (%) – Monthly Average	60%
• Communications: Public Confidence (%) – Monthly Average	65%
• Social Media Channel Growth (# New Followers) (Twitter, Instagram, Facebook, LinkedIn, YouTube)	19,200
• Social Media Engagements (#)	150,000
• Energy Conservation Portfolio (New incremental GWh/year)	500
• BC Hydro Customer Satisfaction Index (%)	85%
• Accounts Receivable >60 Days (% of Revenue)	5%
• Contact Centre – 10+ Mins Wait Time (%)	2%
• Contact Centre – First Call Resolution (%)	75%

**BC Hydro Fiscal 2022
Revenue Requirements Application**

Appendix P

Fiscal 2020 Variance Explanations

BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

Attachment 1 to Section 6

Fiscal 2020 Financial Schedules and Variance Explanations

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In sections 1 through 9, variance explanations are provided for actual gross amounts in fiscal 2020 compared to the fiscal 2020 Evidentiary Update in the F2020-F2021 RRA. With the exception of domestic energy sales variances, all explanations are provided where variances between actual and planned amounts are greater than 10 per cent, with a minimum variance threshold of \$5 million. Domestic energy sales variance explanations are provided for each customer sector.

1 Domestic Energy Sales Variance Explanations (Schedule 14.0)

This section compares fiscal 2020 actual domestic energy sales amounts in GWh with the fiscal 2020 Evidentiary Update.

Table 1 Fiscal 2020 Domestic Energy Sales Variances

(GWh)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
1 Residential	14.0 L1	18,151	17,993	(157)	-1%
2 Light Industrial and Commercial	14.0 L2	18,915	18,692	(224)	-1%
3 Large Industrial	14.0 L3	14,592	13,383	(1,210)	-8%
4 Other	14.0 L4:L10	1,638	1,863	226	14%
5 Total Domestic Energy Sales	14.0 L11	53,296	51,931	(1,365)	-3%

Overall, actual domestic energy sales in fiscal 2020 were 1,365 GWh (or 3 per cent) lower than the fiscal 2020 Evidentiary Update. This was due to:

- Line 1 - Actual residential sales were 157 GWh (or 1 per cent) lower than the fiscal 2020 Evidentiary Update. Variances in residential sales are driven by three main factors: electricity sales per account (use per account), temperature and number of accounts. In fiscal 2020, the residential sales variance was driven primarily by lower than expected use per account, partly offset by colder temperatures. The lower use per account variance can be attributed to many different factors and while the exact drivers are not known, the likely drivers are higher Demand-Side Management savings, denser housing developments

(more multiple unit dwellings), fewer people per account, and changes in appliance mix resulting in more efficient appliances (appliance stock turnover). Temperatures were colder than normal, primarily in October and March, which drove higher sales that partially offset the lower use per account variance. The total number of residential accounts was 2,000 (less than 1 per cent) higher than plan and did not contribute significantly to the sales variance;

- Line 2 - Actual light industrial and commercial sales were 224 GWh (or 1 per cent) lower than the fiscal 2020 Evidentiary Update. Most of the variance was due to curtailed operations within the light industrial wood manufacturing sector, which was driven by many factors including high log costs and low lumber prices. The commercial sector also experienced slightly lower sales relative to plan due to lower use per account. The commercial sector is comprised of a diverse group of business classes and lower use per account can be attributed to many different factors with continued energy efficiency improvements being a likely contributor;
- Line 3 - Actual large industrial sales were 1,210 GWh (or 8 per cent) lower than the fiscal 2020 Evidentiary Update. The variance can primarily be attributed to the following sectors: Pulp and Paper (due to curtailed operations driven by fibre shortages and various operational issues); Cryptocurrency (due to customer project delays or cancellations); Oil and Gas (driven by production slowdowns due to weak market conditions); and Wood Manufacturing (due to curtailed operations driven by many factors including high log costs, low lumber prices and labour disputes); and
- Line 4 - Actual energy sales to the Other customer sector were 226 GWh (or 14 per cent) higher than the fiscal 2020 Evidentiary Update, primarily due to transactions under an energy supply contract which were planned under IPPs and Long-Term Commitments as a reduction in Sources of Supply.

2 Domestic Revenue Variance Explanations (Schedule 14.0)

This section compares fiscal 2020 actual domestic revenue amounts with the fiscal 2020 Evidentiary Update.

**Table 2 Fiscal 2020 Domestic Revenues
Variances**

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
1 Residential	14.0 L12	2,197.8	2,168.8	(29.0)	-1%
2 Light Industrial and Commercial	14.0 L13	1,958.8	1,942.0	(16.8)	-1%
3 Large Industrial	14.0 L14	944.7	848.4	(96.2)	-10%
4 Other	14.0 L15:L21	152.1	155.7	3.6	2%
5 Subtotal	14.0 L22	5,253.3	5,114.9	(138.4)	-3%
6 Revenue from Deferral Rider	14.0 L23	-	0.2	0.2	0%
7 Total Domestic Revenues	14.0 L24	5,253.3	5,115.1	(138.2)	-3%

Actual domestic revenues in fiscal 2020 were \$138.2 million (or 3 per cent) lower than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 1 - Residential revenue was \$29.0 million (or 1 per cent) lower, driven by lower sales, as described in section 1 above;
- Line 2 - Light industrial and commercial revenue was \$16.8 million (or 1 per cent) lower, mainly due to lower sales, as described in section 1 above;
- Line 3 - Large industrial customer revenue was \$96.2 million (or 10 per cent) lower due to lower sales, as described in section 1, as well as a lower average rate due to a different mix of customer rates than planned (fewer sales were at the Rate Schedule 1823 A exempt rate (\$50.97/MWh) and more sales were at the Tier 1 rate (\$45.31/MWh)); and
- Other revenue was \$3.6 million (or 2 per cent) higher, mainly due to the transactions described in section 1. These transactions were planned under IPPs and Long-Term Commitments as a reduction in Cost of Energy.

3 Cost of Energy Variance Explanations (Schedule 4.0)

This section compares fiscal 2020 actual sources of energy supply and cost of energy amounts with the fiscal 2020 Evidentiary Update.

Table 3 Fiscal 2020 Sources of Supply

(GWh)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
1 Water Rentals	4.0 L1	39,368	40,383	1,015	3%
2 IPPs and Long-Term Commitments	4.0 L5	13,949	14,475	526	4%
3 Market Electricity Purchases	4.0 L8	5,104	3,471	(1,633)	-32%
4 Natural Gas for Thermal Generation	4.0 L2	181	171	(10)	-5%
5 Surplus Sales	4.0 L9	(84)	(182)	(98)	117%
6 Net Purchases (Sales) from Powerex	4.0 L10	468	(940)	(1,407)	-301%
7 Non-Integrated Area	4.0 L6	118	106	(11)	-10%
8 Exchange Net	4.0 L3	(473)	(581)	(108)	23%
9 Total Sources of Supply	4.0 L12	58,630	56,903	(1,727)	-3%

Actual fiscal 2020 energy supplied was 1,727 GWh (or 3 per cent) lower than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 3 – Lower market electricity purchases due to lower domestic load requirements and higher water inflows starting in late summer; and
- Line 6 – Higher net sales to Powerex due to higher opportunities for trade exports resulting from lower domestic load requirements and higher water inflows starting in late summer.

Partially offset by:

- Line 1 - Higher hydro generation due to higher water inflows starting in late summer.

Table 4 Fiscal 2020 Cost of Energy Variances

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
Heritage Energy					
1 Water Rentals	4.0 L13	329.3	331.6	2.3	1%
2 Natural Gas for Thermal Generation	4.0 L14	7.5	7.1	(0.4)	-6%
3 Domestic Transmission - Other	4.0 L15	24.5	24.8	0.3	1%
4 Non-Treaty Storage and Libby Coordination Agreements	4.0 L16	15.0	37.7	22.7	152%
5 Remissions and Other	4.0 L17	(25.2)	(42.4)	(17.2)	68%
6 Subtotal	4.0 L18	351.2	358.8	7.7	2%
Non-Heritage Energy					
7 IPPs and Long-Term Commitments	4.0 L19	1,294.7	1,314.0	19.3	1%
8 Non-Integrated Area	4.0 L20	30.5	31.3	0.7	2%
9 Gas & Other Transportation	4.0 L21	3.7	4.5	0.8	23%
10 Water Rentals (Waneta 2/3)	4.0 L22	3.5	3.3	(0.2)	N/A
11 Subtotal	4.0 L23	1,332.4	1,353.1	20.7	2%
Market Energy					
12 Market Electricity Purchases	4.0 L24	211.6	133.1	(78.4)	-37%
13 Surplus Sales	4.0 L25	(0.4)	(1.0)	(0.6)	138%
14 Net Purchases (Sales) from Powerex	4.0 L26	33.1	(35.2)	(68.3)	-206%
15 Domestic Transmission - Export	4.0 L27	1.1	2.0	0.9	86%
16 Subtotal	4.0 L28	245.3	99.0	(146.4)	-60%
17 Total Gross Cost of Energy	1.0 L1	1,928.9	1,810.9	(118.0)	-6%

Fiscal 2020 actual gross Cost of Energy was \$118.0 million (or 6 per cent) lower than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 5 - Higher recoveries from remissions and other of \$17.2 million due to higher remission credits for the Bridge River system and John Hart generating station which were eligible for full remission credits in fiscal 2020. Remission credits were not planned for Bridge River, while partial remissions were planned for John Hart;
- Line 12 - Lower market electricity purchases of \$78.4 million due to lower domestic load requirements, higher water inflows than planned and higher hydro generation starting in late summer; and
- Line 14 - Higher net sales of \$68.3 million to Powerex due to higher than planned net exports as a result of higher inflows and hydro generation, starting in late summer, and lower domestic load requirements.

Partially offset by:

- Line 4 - Higher water transactions associated with Non-Treaty Storage and Libby Coordination agreements of \$22.7 million due to higher storage of water driven by lower market electricity prices and favourable storage opportunities during fiscal 2020.

4 Operating Costs and Provisions Variance Explanations (Schedule 5.0)

This section compares fiscal 2020 actual gross operating costs and provisions amounts with the fiscal 2020 Evidentiary Update.

Table 5 Fiscal 2020 Operating Costs and Provisions Variances

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
Integrated Planning	5.0 L1	290.8	289.3	(1.5)	-1%
Capital Infrastructure Project Delivery	5.0 L2	80.1	80.1	0.1	0%
Operations	5.0 L3	237.3	246.1	8.8	4%
Safety	5.0 L4	56.8	55.0	(1.9)	-3%
Finance, Technology, Supply Chain	5.0 L5	262.6	265.1	2.5	1%
People, Customer, Corporate Affairs	5.0 L6	110.6	110.0	(0.6)	0%
Other	5.0 L7	(244.3)	(241.4)	2.9	-1%
Base Operating Costs	5.0 L8	793.8	804.2	10.3	1%
IFRS Ineligible Capitalized Costs	5.0 L9	170.1	170.1	-	0%
Waneta 2/3	5.0 L10	5.7	5.4	(0.3)	N/A
Customer Crisis Fund	5.0 L11	5.3	4.4	(0.9)	N/A
Subtotal	5.0 L12	181.1	179.8	(1.2)	-1%
Deferred Account Additions	5.0 L15	-	(1.4)	(1.4)	N/A
Regulatory Account Additions	5.0 L24	157.1	132.6	(24.5)	-16%
Subtotal		157.1	131.2	(25.9)	-16%
Total Gross Operating Costs	5.0 L25	1,132.0	1,115.2	(16.8)	-1%
Net Provisions & Other	5.0 L38	116.2	128.7	12.5	11%
Regulatory Account Additions - Provisions & Other	5.0 L45	(9.1)	48.0	57.2	-627%
Total Gross Provisions & Other	5.0 L46	107.1	176.8	69.6	65%
Total Gross Operating Costs and Provisions	1.0 L2	1,239.1	1,292.0	52.9	4%

Fiscal 2020 actual gross Operating Costs and Provisions were \$52.9 million (or 4 per cent) higher than the fiscal 2020 Evidentiary Update. Of this amount, \$57.2 million (line 18 in [Table 5](#) above) was related to higher regulatory account

additions for provisions, \$12.5 million (line 17 in [Table 5](#) above) was related to higher net provisions and other, and \$10.3 million (line 8 in [Table 5](#) above) was related to higher base operating costs. These amounts were partially offset by \$24.5 million (line 14 in [Table 5](#) above) related to lower regulatory account additions for operating costs.

Variances of \$57.2 million related to higher regulatory account additions for provisions and other and variances of \$24.5 million related to lower regulatory account additions for operating costs, netting to \$32.7 million were primarily due to:

- An increase in the Environmental Provisions Regulatory Account of \$51.2 million due to an increase in the Polychlorinated Biphenyl (**PCB**) provision of \$44.9 million and an increase in the Asbestos Remediation provision of \$6.3 million. The provisions increased due to increases in forecast PCB and Asbestos remediation costs, and decreases in discount rates (resulting in an increase in the present value of the forecast remediation expenditures); and
- Higher than planned increase in the Real Property Sales Regulatory Account of \$13.5 million due to surplus property sales being delayed to future years.

Partially offset by:

- Lower than planned increase in the Demand-Side Management Regulatory Account of \$13.7 million due to fewer project completions and studies than planned, primarily in the industrial sector, and due to cancelations and shifts in timing for some capacity-focused Demand-Side Management activities;
- A decrease in the Dismantling Costs Regulatory Account of \$8.5 million primarily due to lower than planned dismantling costs for the John Hart Generating Station Replacement project, and lower end of life plant and equipment removal costs under various projects and programs;

1 • A decrease in the Storm Restoration Costs Regulatory Account of \$7.8 million
2 due to lower than planned expenditures for storm restoration. Planned storm
3 restoration expenditures are based on a five-year average of actual storm
4 restoration costs. In fiscal 2020, BC Hydro experienced relatively less storm
5 activity (fewer and less severe wildfires, windstorms, snow events) and
6 accordingly, actual storm restoration costs were lower than plan; and

7 • Other variances, totalling \$2.0 million.

8 Variances of \$12.5 million related to net provisions and other were primarily due to:

9 • Higher capital asset retirements and project write-offs of \$8.6 million primarily
10 due to partial project costs being written off as a result of scope changes or as
11 a result of revisiting leading alternatives on certain projects due to higher
12 project cost estimates. This included a \$6.5 million write-off of the Metro North
13 Transmission project. The write-off occurred because the project was cancelled
14 due to a lower load forecast which showed that the project will not be required
15 until 2029 at the earliest. The costs were written-off in accordance with
16 accounting rules, as there were no probable future economic benefits; and

17 • Other variances, totaling \$3.9 million.

18 Variances of \$10.3 million related to base operating costs were primarily due to
19 higher than planned personnel costs, including employees unable to charge to
20 capital/maintenance work programs as a result of the COVID-19 social distancing
21 measures BC Hydro put in place in March 2020.

22 **5 Taxes Variance Explanations (Schedule 6.0)**

23 This section compares fiscal 2020 actual taxes amounts with the fiscal 2020
24 Evidentiary Update.

Table 6 Fiscal 2020 Taxes Variances

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
1 Grants in Lieu	6.0 L15	110.8	111.3	0.5	0%
2 School Taxes	6.0 L16	138.3	137.5	(0.8)	-1%
3 Waneta 2/3 Property Taxes	6.0 L17	0.6	0.9	0.3	N/A
4 Subtotal Before Regulatory Accounts	6.0 L17	249.8	249.7	(0.1)	0%
5 Deferred Account Additions	6.0 L	-	-	-	N/A
6 Total Gross Taxes	1.0 L3	249.8	249.7	(0.1)	0%

Fiscal 2020 actual gross Taxes of \$249.7 million were comparable to the fiscal 2020 Evidentiary Update amount of \$249.8 million.

6 Amortization Variance Explanations (Schedule 7.0)

This section compares fiscal 2020 actual amortization amounts with the fiscal 2020 Evidentiary Update.

Table 7 Fiscal 2020 Amortization Variances

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
1 Amortization of Capital Assets	7.0 L5	885.4	885.8	0.4	0%
2 IPP Capital Leases	7.0 L7	88.9	88.9	-	0%
3 Other Leases	7.0 L8	3.4	2.6	(0.8)	-23%
4 Subtotal Before Regulatory Accounts		977.8	977.3	(0.4)	0%
5 Deferred Account Additions	7.0 L10	-	0.4	0.4	N/A
6 Total Gross Amortization	1.0 L4	977.8	977.7	(0.1)	0%

Fiscal 2020 actual gross Amortization of \$977.7 million was comparable to the fiscal 2020 Evidentiary Update amount of \$977.8 million.

7 Finance Charges Variance Explanations (Schedule 8.0)

This section compares fiscal 2020 actual finance charges amounts with the fiscal 2020 Evidentiary Update.

1 **Table 8 Fiscal 2020 Finance Charges Variances**

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
1 Sinking Fund Income	8.0 L9	(7.8)	(9.1)	(1.2)	16%
2 Long-Term Debt Costs	8.0 L10	825.3	824.9	(0.4)	0%
3 Short-Term Debt Costs	8.0 L11	63.8	47.5	(16.2)	-25%
4 Interest Capitalized	8.0 L12	(181.5)	(175.5)	6.0	-3%
5 Other (Income) / Loss	8.0 L13	39.2	50.5	11.3	29%
6 IPP Capital Leases	8.0 L14	48.4	48.4	-	0%
7 Accretion - Non-Deferrable	8.0 L15	1.3	1.3	(0.0)	-1%
8 Non-Current PEB	8.0 L16	(36.5)	62.1	98.6	-270%
9 Other Leases	8.0 L17	1.0	1.3	0.2	N/A
10 Subtotal Before Regulatory Accounts	8.0 L18	753.1	851.5	98.3	13%
11 Regulatory Account Additions	8.0 L7	121.8	805.3	683.5	561%
12 Total Gross Finance Charges	1.0 L5	874.9	1,656.8	781.8	89%

2 Fiscal 2020 actual gross Finance Charges were \$781.8 million (or 89 per cent)
3 higher than the fiscal 2020 Evidentiary Update. This was primarily due to:

- 4 • Line 5 - Higher other loss of \$11.3 million primarily due to lower than planned
5 interest income on US dollar bank balances and higher foreign exchange
6 losses on US payables balances given the decline of the Canadian dollar
7 against the US dollar;
- 8 • Line 8 - Higher non-current post-employment benefit costs of \$98.6 million as
9 the rate of return on pension plan assets (prescribed under International
10 Financial Reporting Standards) was lower than the planned rate of return; and
- 11 • Line 11 - Higher regulatory account additions of \$683.5 million primarily due to
12 a decrease in the fair value of future debt hedges as a result of changes in
13 forward interest rates. Losses on future debt hedges are offset by lower interest
14 costs when the future debt is issued.

15 Partially offset by:

- 16 • Line 3 - Lower short-term debt costs of \$16.2 million due to lower interest rates
17 and lower outstanding short-term debt balance.

8 Miscellaneous Revenue Variance Explanations (Schedule 15.0)

This section compares fiscal 2020 actual miscellaneous revenue amounts with the fiscal 2020 Evidentiary Update.

Table 9 Fiscal 2020 Miscellaneous Revenue Variances

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
		1	2	3=2-1	4=3/1
1 Amortization of Contributions	15.0 L1+L8+L12	59.6	64.0	4.4	7%
2 External OATT	15.0 L4	15.9	10.7	(5.2)	-33%
3 FortisBC Wheeling Agreement	15.0 L5	5.2	5.2	(0.0)	0%
4 Secondary Revenue (MMBU, Secondary Use, Other)	15.0 L6+L11+L28	23.9	28.0	4.2	17%
5 Interconnections	15.0 L7	2.2	6.4	4.2	190%
6 Meter/Trans Rents & Power	15.0 L14	14.6	16.1	1.5	11%
7 Smart Metering & Infrastructure	15.0 L15	2.1	2.2	0.1	6%
8 Diversion Net Recoveries	15.0 L16	0.1	0.2	0.1	52%
9 Other Operating Recoveries	15.0 L17	4.5	4.1	(0.3)	-7%
10 Customer Crisis Fund Rider Revenue	15.0 L18	5.3	4.4	(0.9)	N/A
11 Waneta 2/3	15.0 L24	84.9	84.7	(0.2)	N/A
12 Corporate General Rents	15.0 L26	3.7	3.9	0.2	5%
13 Late Payment Charges	15.0 L27	7.9	7.1	(0.8)	-10%
14 NTL Supplemental Charge	15.0 L9	2.3	2.3	0.0	2%
15 Other (Income) / Loss	15.0 L2+L19+L29	5.4	6.6	1.3	24%
16 Subtotal Before Regulatory Accounts	15.0 L31	237.6	246.0	8.5	4%
17 Deferral Account Additions	15.0 L33	3.1	1.3	(1.8)	N/A
18 Total Gross Miscellaneous Revenue	1.0 L7	240.7	247.3	6.6	3%

Fiscal 2020 actual gross Miscellaneous Revenue was \$6.6 million (or 3 per cent) higher than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 1 - Higher amortization of contributions of \$4.4 million, primarily due to a change in the scope of a project, resulting in a partial write-off and higher mass asset retirements than planned which resulted in the write-off at the associated contributions;
- Line 4 - Higher secondary revenue of \$4.2 million, primarily due to higher than planned house moves and temporary connections, higher than planned transmission third party projects for shared assets, and higher rental revenues; and

- Line 5 - Higher interconnections of \$4.2 million, primarily due to higher than planned project revenues from feasibility, system and facilities studies.

Partially offset by:

- Line 2 - Lower external OATT revenue of \$5.2 million, primarily due to the resale of long-term transmission service from an external customer to BC Hydro.

9 Summary of Inter-Segment Revenue Variance Explanations (Schedule 3.0)

This section compares fiscal 2020 actual inter-segment revenue amounts with the fiscal 2020 Evidentiary Update.

Table 10 Fiscal 2020 Inter-Segment Revenue Variances

(\$ million)	Schedule Reference	F2020			
		Update	Actual	Diff	% Diff
1 Powerex - Business Support Allocation	3.0 L1	(2.9)	(2.9)	-	0%
2 Mark to Market Losses (Gains)	3.0 L2	(1.4)	0.8	2.2	N/A
3 Powerex PTP Charges	3.0 L3	(41.5)	(49.8)	(8.3)	20%
4 BC Hydro PTP Charges	3.0 L4	(19.1)	(20.1)	(1.0)	5%
5 Total Inter-Segment Revenue	1.0 L8	(64.9)	(72.0)	(7.1)	11%

Fiscal 2020 actual Inter-Segment revenues were \$7.1 million (or 11 per cent) higher than the fiscal 2020 Evidentiary Update due to higher point-to-point transmission charges allocated to Powerex (line 3 in [Table 10](#) above), driven by higher than planned transmission rates per unit and higher trade account exports due to favourable trade export opportunities.

10 **Capital Expenditures and Capital Additions Variance Explanations**

The following tables and discussion provide information on the variances between fiscal 2020 actual capital expenditures and capital additions compared to the Fiscal 2020 RRA Plan amounts in the F2020-F2021 RRA, which was based on a Currency Date of April 1, 2018. There were no changes to the capital expenditures and capital additions as part of the Evidentiary Update to the F2020-F2021 RRA.

On an annual basis, BC Hydro manages over 900 projects and programs in various project and program phases. Capital expenditures and capital additions in a fiscal year are impacted by a number of factors that may give rise to variances from plan, including project progression and timing, potential changes in scope due to as-found equipment conditions or other factors to meet business requirements, and cost changes due to market conditions or other factors.

In addition, capital projects frequently take several years to complete, and any variances from plan in a particular year may be offset by project expenditures and additions in a subsequent year. The variances provided are against planned annual capital expenditures and additions and are not necessarily reflective of the total project cost. While year-over-year capital project cash flows may vary from annual plan amounts, overall BC Hydro is delivering its projects on budget as reported through BC Hydro's Service Plan Budget to Actual Cost performance metric.

Variances are provided for each main asset category in the tables below. The amounts presented in the tables in this section may not add due to rounding. The actual capital additions information has been presented using the same classification as the planned capital additions as presented in the tables in Chapter 6 of BC Hydro's F2020-F2021 RRA.

In general, explanations are provided where variances between actual and planned amounts are greater than 10 per cent, with a minimum variance threshold of \$10 million.

10.1 Overall Capital Expenditures and Additions Variance Explanations

[Table 11](#) and [Table 12](#) below provide BC Hydro's fiscal 2020 capital expenditures and capital additions by main asset category.

Table 11 Fiscal 2020 Capital Expenditures Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	345.1	305.1	(40.0)	-12%
Site C Project	1,530.0	1,619.1	89.1	6%
Transmission & Distribution	895.2	898.8	3.6	0%
Business Support				
Technology	93.5	132.2	38.7	41%
Properties	58.9	56.4	(2.5)	-4%
Fleet	26.2	27.0	0.8	3%
Business Support - Other and Other Technology	39.5	32.8	(6.7)	-17%
Total Gross	2,988.3	3,071.4	83.1	3%
Less: Contribution in Aid	(157.8)	(179.0)	(21.2)	13%
Total	2,830.5	2,892.5	62.0	2%

Table 12 Fiscal 2020 Capital Additions Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	314.7	359.5	44.8	14%
Site C Project	27.9	12.9	(15.0)	-
Transmission & Distribution	796.0	669.3	(126.7)	-16%
Business Support				
Technology	141.0	93.7	(47.3)	-34%
Properties	40.0	44.3	4.3	11%
Fleet	26.2	29.2	3.0	12%
Business Support - Other and Other Technology	45.3	27.2	(18.1)	-40%
Total Gross	1,391.0	1,236.1	(154.9)	-11%
Less: Contribution in Aid	(146.1)	(140.5)	5.6	-4%
Total	1,244.9	1,095.6	(149.3)	-12%

1 Fiscal 2020 capital expenditures were \$83.1 million (or 3 per cent) above the
2 Fiscal 2020 RRA Plan, excluding contribution in aid, primarily because:

- 3 • The Site C project was \$89.1 million above plan due to advancement of work
4 and claims as discussed in section [10.6](#); and
- 5 • Technology was \$38.7 million above plan due to certain software subscription
6 license costs which were determined to be eligible for capitalization but were
7 expected to be operating costs.

8 The increase in capital expenditures above was partially offset by lower than
9 planned Generation capital expenditures of \$40.0 million, primarily due to various
10 projects schedule changes as discussed in section [10.2](#).

11 Fiscal 2020 gross capital additions were \$154.9 million (or 11 per cent) below the
12 Fiscal 2020 RRA Plan, excluding contribution in aid, primarily because:

- 13 • The Supply Chain Applications project (included in the Technology line) was
14 below plan by \$57.4 million as the project was delayed to fiscal 2021. This
15 delay was due to a schedule extension for the build and testing activities, as
16 well as the delay in the project go-live training, in response to the COVID-19
17 pandemic; and
- 18 • Transmission and Distribution capital additions were below plan by
19 \$126.7 million, primarily due to lower than planned capital additions of
20 \$18.7 million for the Bringing additional capacity from ARN to Tilbury
21 (FV-FVW-057) project, due to a delayed completion date, as well as various
22 projects and programs schedule changes which shifted the timing of placing
23 certain assets in-service, as discussed in section [10.3](#) and [10.4](#).

24 The decrease in capital additions was partially offset by higher than planned
25 Generation capital additions of \$44.8 million. This was primarily a result of certain
26 assets being placed in-service in fiscal 2020 rather than in prior year due to the

- 1 delayed additions of \$28.2 million for the John Hart Generating Station
2 Replacement project, and \$25.2 million for the Ruskin Dam and Powerhouse
3 Upgrade project as a result of schedule extensions.

4 **10.2 Generation Capital Expenditures and Additions Variance** 5 **Explanations**

6 Generation capital expenditures and capital additions in fiscal 2020 are presented in
7 [Table 13](#) and [Table 14](#) below. Results exclude amounts for the Site C project, which
8 are presented separately in section [10.6](#) below.

9 **Table 13 Fiscal 2020 Generation Capital**
10 **Expenditures Variances (excluding Site C**
11 **Project)**

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	3.2	2.6	(0.6)	-17%
Redevelopment / Rehabilitation	28.6	29.5	0.9	3%
Dam Safety	68.8	44.7	(24.1)	-35%
Sustaining - Other	241.0	220.8	(20.2)	-8%
Total Hydroelectric Generation	341.7	297.6	(44.1)	-13%
Total Non-Integrated Areas	8.7	5.8	(2.9)	-33%
Total Thermal Generation	6.6	1.7	(4.9)	-73%
Less: Portfolio Risk Adjustment	(11.9)	-	11.9	-100%
Total Gross	345.1	305.1	(40.0)	-12%
Less: Contribution in Aid	-	0.0	0.0	-
Total	345.1	305.1	(40.0)	-12%

**Table 14 Fiscal 2020 Generation Capital Additions
Variances (excluding Site C Project)**

Generation (\$ million)	F2020			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	2.7	-	(2.7)	-100%
Redevelopment / Rehabilitation	42.8	96.2	53.4	125%
Dam Safety	49.3	7.4	(41.9)	-85%
Sustaining - Other	199.4	253.4	54.0	27%
Total Hydroelectric Generation	294.1	357.0	62.9	21%
Total Non-Integrated Areas	7.9	1.2	(6.7)	-85%
Total Thermal Generation	3.8	1.4	(2.4)	-63%
Plus: Portfolio Risk Adjustment	8.9	-	(8.9)	-100%
Total Gross	314.7	359.5	44.8	14%
Less: Contribution in Aid	-	(0.0)	(0.0)	-
Total	314.7	359.5	44.8	14%

Growth Capital

In general, excluding the Site C Project, planned capital expenditures and additions for Generation Growth Capital are a small component of the annual capital plan. The majority of the capital investments in the Generation portfolio are driven by the need to address issues and risks associated with existing facilities.

Fiscal 2020 capital expenditures and capital additions for Generation Growth Capital were comparable to the Fiscal 2020 RRA Plan.

Redevelopment/ Rehabilitation

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were \$53.4 million (or 125 per cent) above the Fiscal 2020 RRA Plan. This was primarily because:

- The John Hart Generating Station Replacement project was \$28.2 million above the fiscal 2020 planned expenditures due to timing. The project was above the fiscal 2020 planned expenditures because the project schedule was extended into fiscal 2020 in order to complete the trailing and final deficiency

work of the plant construction. These remaining trailing costs are a small percentage of the total project costs, which are forecasted to be under the approved authorized project cost; and

- The Ruskin Dam and Powerhouse Upgrade project was \$25.2 million above the fiscal 2020 planned expenditures due to timing. The project was above the fiscal 2020 planned expenditures because the project schedule was extended into Fiscal 2020 due to the new Dam Safety Diesel Generation unit commissioning and additional time needed to complete the final deficiency work. These remaining trailing costs are a small percentage of the total project costs, which are forecasted to be under the approved authorized project cost.

Dam Safety

Fiscal 2020 capital expenditures were \$24.1 million (or 35 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The Bridge River 1 Improve Slope Drainage project was \$7.0 million below plan because the re-planning of the project was extended due to delayed conclusion of land negotiations with Indigenous Nations;
- The Peace Canyon Spillway Gate Upgrade project was \$5.9 million below plan because the project was cancelled due to the high cost relative to the amount of risk reduction that would be achieved;
- The Bridge River 1 - Mitigate Surge Spill Hazard project was \$4.2 million below plan because the design was delayed due to the complexity of site conditions and construction safety risk mitigation considerations; and
- The Strathcona Upgrade Discharge project was \$2.9 million below plan because the project schedule was delayed due to additional time required at the Feasibility stage to confirm the Gate configuration and reliability requirements.

The remaining variance of \$4.1 million was due to smaller below plan variances on various projects.

Fiscal 2020 capital additions were \$41.9 million (or 85 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The W.A.C. Bennett Dam Spillway Gate Upgrade project was \$25.9 million below plan because the construction start date was delayed due to longer than anticipated time required to finalize the Design Build contract. The project in-service date is now planned for fiscal 2021;
- The Bridge River 1 Improve Slope Drainage project was \$8.2 million below plan because the re-planning of the project was extended due to delayed conclusion of land negotiations with Indigenous Nations. The project in-service date is now planned for fiscal 2025;
- The Bridge River 1 - Mitigate Surge Spill Hazard project was \$4.9 million below plan because the design was delayed due to the complexity of site conditions and construction safety risk mitigation considerations. The project in-service date is now planned for fiscal 2022; and
- The Wahleach Unit 1 Tailrace Tunnel Improvement was \$3.1 million below plan because the required concrete work has been rescheduled to fiscal 2021 mainly due to longer than anticipated steel culvert recoating work. The project in-service date is now planned for fiscal 2022.

Sustaining – Other

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were \$54.0 million (or 27 per cent) above the Fiscal 2020 RRA Plan. This was primarily because:

-
- 1 • The Bridge River 2 Unit 5 and 6 Upgrade project was \$40.9 million above plan
2 because the project in-service date was delayed from fiscal 2019 to fiscal 2020
3 reflecting a delay in the project schedule due to the time required to study two
4 additional feasibility stage alternatives;
 - 5 • The Cheakamus Unit 1 and 2 Generator Replacement project was \$27.7 million
6 above plan because both units were put in-service with expenditures
7 recognized as capital additions in fiscal 2020; however, one of the units had a
8 planned in-service date in fiscal 2019; and
 - 9 • The Wahleach Fire Risk Reduction project was \$8.3 million above plan
10 because the construction completion was delayed from fiscal 2019 to
11 fiscal 2020 due to design change which resulted from the as-found geotechnical
12 conditions and worse than expected winter weather.

13 The increase in capital additions outlined above was partially offset by:

- 14 • The Lake Buntzen 1 - Power House Crane Upgrade project was \$6.9 million
15 below plan because the project in-service date was delayed to fiscal 2021 due
16 to scheduling overlaps amongst BC Hydro projects with the same crane
17 contractor; and
- 18 • The Waneta – Sustaining projects were \$4.7 million below plan because the
19 in-service dates were delayed. This was mainly due to the Unit 3 Life Extension
20 work transitioning into the execution phase in the winter of 2020, primarily due
21 to delays in Teck getting internal funding approvals;
- 22 • The Jordan Fire Risk Reduction project was \$4.3 million below plan because
23 the project in-service date was delayed to fiscal 2022 due to additional time
24 required to resolve issues encountered while commissioning the fire protection
25 water supply system; and

-
- \$7.0 million of smaller below plan variances on various projects primarily due to projects schedule changes.

Non-Integrated Areas and Diesel and Thermal Generation

Fiscal 2020 capital expenditures and additions for Non-Integrated Areas and Diesel and Thermal Generation were comparable to the Fiscal 2020 RRA Plan.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment is meant to account for the uncertainty in the schedule and cost of projects. The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical project delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

The Fiscal 2020 RRA Plan Portfolio Risk Adjustment amount was \$(11.9) million for capital expenditures and \$8.9 million for capital additions.

10.3 Transmission Capital Expenditures and Additions Variance Explanations

Transmission fiscal 2020 capital expenditures and capital additions are provided in [Table 15](#) and [Table 16](#), below.

Table 15 Fiscal 2020 Transmission Capital Expenditures Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	107.9	79.6	(28.3)	-26%
Bulk System Reinforcement	12.0	5.9	(6.1)	-51%
Station Expansion & Modification	11.9	9.1	(2.8)	-23%
Feeder Positions / Section Additions	1.6	0.6	(1.0)	-63%
Generator Interconnections	5.1	8.3	3.2	63%
Transmission Load Interconnection	58.7	56.1	(2.6)	-4%
Total Growth	197.2	159.6	(37.6)	-19%
Transmission Sustain - Stations				
Circuit Breakers	16.3	20.5	4.2	25%
Other Power Equipment	63.5	52.2	(11.3)	-18%
Protection and Control	18.4	7.6	(10.8)	-58%
Stations Auxiliary Equipment	25.6	25.9	0.3	1%
Stations Risk Mitigation	12.9	8.9	(4.0)	-31%
Telecommunications	25.4	20.4	(5.0)	-20%
Total Sustain - Stations	162.1	135.6	(26.5)	-16%
Transmission Sustain - Lines				
Cable Sustainment	5.0	7.5	2.5	51%
O/H Lines Life Extension	45.5	51.9	6.4	14%
O/H Lines Performance Improvement	1.4	1.7	0.3	22%
O/H Lines Risk Mitigation	10.7	16.2	5.5	51%
ROW Sustainment	9.7	10.6	0.9	10%
Third Party Requested Transmission Line Relocations	10.0	(0.2)	(10.2)	-102%
Total Sustain - Lines	82.3	87.7	5.4	7%
Less: Portfolio Risk Adjustment	(34.0)	-	34.0	-100%
Total Gross	407.7	382.9	(24.8)	-6%
Less: Contribution in Aid	(23.7)	(17.9)	5.8	-24%
Total	384.0	365.0	(19.0)	-5%

**Table 16 Fiscal 2020 Transmission Capital
Additions Variances**

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	83.8	84.5	0.7	1%
Bulk System Reinforcement	0.1	1.2	1.1	1053%
Station Expansion & Modification	2.5	2.0	(0.5)	-21%
Feeder Positions / Section Additions	2.5	0.5	(2.0)	-82%
Generator Interconnections	1.2	-	(1.2)	-100%
Transmission Load Interconnection	7.8	(0.0)	(7.8)	-100%
Total Growth	97.9	88.0	(9.9)	-10%
Transmission Sustain - Stations				
Circuit Breakers	28.0	6.9	(21.1)	-75%
Other Power Equipment	21.9	5.7	(16.2)	-74%
Protection and Control	11.2	3.6	(7.6)	-68%
Stations Auxiliary Equipment	40.1	8.0	(32.1)	-80%
Stations Risk Mitigation	4.0	3.7	(0.3)	-8%
Telecommunications	13.6	6.1	(7.5)	-55%
Total Sustain - Stations	118.8	34.0	(84.8)	-71%
Transmission Sustain - Lines				
Cable Sustainment	4.1	6.7	2.6	62%
O/H Lines Life Extension	49.1	38.6	(10.5)	-21%
O/H Lines Performance Improvement	1.4	1.1	(0.3)	-23%
O/H Lines Risk Mitigation	16.2	19.4	3.2	20%
ROW Sustainment	19.3	11.6	(7.7)	-40%
Third Party Requested Transmission Line Relocations	9.0	0.3	(8.7)	-97%
Total Sustain - Lines	99.1	77.6	(21.5)	-22%
Less: Portfolio Risk Adjustment	(22.0)	-	22.0	-100%
Total Gross	293.8	199.7	(94.1)	-32%
Less: Contribution in Aid	(15.2)	(3.0)	12.2	-81%
Total	278.6	196.7	(81.9)	-29%

Transmission Growth - Regional System Reinforcement

Fiscal 2020 capital expenditures were \$28.3 million (or 26 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The Fort St. John and Taylor Electric Supply project was \$8.0 million below plan because part of the substation construction work planned for fiscal 2020 was completed in fiscal 2019 due to higher contractor productivity. In addition,

certain construction work was deferred to fiscal 2021 due to colder than expected winter weather conditions at the construction site;

- The Peace Region Electric Supply (**PRES**) project was \$6.6 million below plan because the costs of substation and transmission line contracts were lower than estimated due to favourable market pricing from the suppliers;
- The Metro North Transmission (**MNT**) project was \$6.5 million below plan because the project was cancelled due to a lower load forecast which showed that the project will not be required until 2029 at the earliest. The expenditures incurred did not meet the capitalization criterion of providing future economic benefits as the design and engineering work cannot be reused when project is re-initiated; and
- The West Kelowna Transmission and Westbank Upgrade Projects were \$6.0 million below plan because the project schedule was delayed due to the project returning to the Conceptual Design stage to revisit other alternatives.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

All other line items under Transmission Growth in fiscal 2020 for both capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

Transmission Sustain-Stations

Circuit Breakers

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were \$21.1 million (or 75 per cent) below the Fiscal 2020 RRA Plan primarily due to:

- The BND 60kV CB and Relay Building Replacement project was \$11.3 million below plan because it was completed ahead of schedule and put in-service in

fiscal 2019 due to the efficiencies gained during the circuit breaker replacement work;

- The Substation 60 KV Circuit Breaker Replacement program was \$4.6 million below plan because fewer than planned units were put in-service in fiscal 2020;
- The System Spare Breaker Purchases project was \$2.7 million below plan because, as a result of early equipment delivery, the project was completed ahead of schedule and put in-service in fiscal 2019; and
- \$2.5 million of smaller below plan variances on various projects.

Other Power Equipment

Fiscal 2020 capital expenditures were \$11.3 million (or 18 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The JOR T1 & T2 Replacement project was \$5.8 million below plan because the project schedule was delayed due to extended construction, and the “must run” operational requirement for Jordan River Generation Station during the winter and spring seasons;
- The Mainwaring Station Upgrade project was \$5.1 million below plan because the project schedule was delayed due to additional time required to finalize the project scope, to complete the preliminary design and project estimates, and to prepare an application for regulatory approval; and
- The SC Excitation Systems Upgrade - VIT/KLY project was \$4.2 million below plan because the implementation phase of the project was delayed to perform additional investigations and studies to define the project scope and schedule.

The decrease in capital expenditures above was partially offset by \$3.8 million of smaller above plan variances on various projects.

Fiscal 2020 capital additions were \$16.2 million (or 74 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The Substation Feeder Section Upgrade program was \$7.3 million below plan because fewer than planned units within the program were put in-service in fiscal 2020;
- The Peace Region to Kelly Lake - Reactor Replacement (Phase 1) project was \$3.6 million below plan because the work was deferred to fiscal 2021 due to the change of project release sequence within the program of projects; and

The remaining variance of \$5.3 million was due to smaller below plan variances on various projects.

Protection and Control

Fiscal 2020 capital expenditures were \$10.8 million (or 58 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The Control PLC984 and RTU Replacement (WSN) project was \$2.9 million below plan because the project was delayed due to interface with, and timing of, a decision on a new Williston Substation (WSN) Control Building as part of the Peace to Kelly Lake Sustainment Project;

The remaining variance of \$7.9 million was due to smaller below plan variances on various projects.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

Stations Auxiliary Equipment

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were \$32.1 million (or 80 per cent) below with the Fiscal 2020 RRA Plan primarily because:

-
- The Stn Service Transfer & AC panels - WSN project was \$10.5 million below plan because the construction was delayed and in-service date was delayed to fiscal 2021 due to a decision to de-scope the upgrade of the existing 500 kV building from the project;
 - The Wood Pole Substation Rep – PSN project was \$5.2 million below plan due to construction delays as a result of steel quality issues;
 - The Wood Pole Substation Rep – MTE project was \$5.3 million below plan due to construction delays as a result of steel quality issues; and
 - The Substation Safety and Minor Capital program was \$4.7 million below plan because fewer than planned units within the program were put in-service in fiscal 2020.

The remaining variance of \$6.4 million was due to smaller below plan variances on various projects.

All other line items under Transmission Sustain-Stations in fiscal 2020 for both capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

Transmission Sustain-Lines

O/H Lines Life Extension

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were \$10.5 million (or 21 per cent) below the Fiscal 2020 RRA Plan, primarily because:

- The Copper Conductor Replace - Phase 2 project was \$10.4 million below plan because it was completed in fiscal 2019; as a result, the capital additions planned for fiscal 2020 were recognized in fiscal 2019.

Third Party Requested Transmission Line Relocations

Fiscal 2020 capital expenditures were \$10.2 million (or 102 per cent) below the Fiscal 2020 RRA Plan primarily due to a customer project cancellation as well as changes on customer requests and timing of the requests.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

All other line items under Transmission Sustain-Lines in fiscal 2020 for both capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment is meant to account for the uncertainty in the schedule and cost of projects. The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical project delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

The Fiscal 2020 RRA Plan Portfolio Risk Adjustment amount was \$(34.0) million in capital expenditures and \$(22.0) million in capital additions.

Contribution in Aid

Fiscal 2020 Transmission Contribution in Aid expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 Transmission Contributions in Aid additions were \$12.2 million (or 81 per cent) below the Fiscal 2020 RRA Plan due to timing differences on the completion of customer work and a lower volume of third-parties requests for relocations than originally forecasted.

10.4 Distribution Capital Expenditures and Additions Variance Explanations

Distribution fiscal 2020 actual to Fiscal 2020 RRA Plan capital expenditures and capital additions are provided in [Table 17](#) and [Table 18](#), below.

The distribution system improvement portfolio is primarily comprised of small projects, with the average project size in the \$1 million to \$2 million ranges with short duration.

The System Expansion and Improvement portfolio is subject to rapidly changing priorities and the planning processes must be dynamic to respond to the emerging needs on the distribution system. This may result in variances in the timing and selection of projects in the portfolio in a given year.

Table 17 Fiscal 2020 Distribution Capital Expenditures Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	231.9	279.0	47.1	20%
System Expansion and Improvement	67.5	60.3	(7.2)	-11%
Uneconomic Extension Assistance	0.6	0.4	(0.2)	-41%
Total Growth	300.0	339.7	39.7	13%
Distribution Sustain				
System Expansion and Improvement	56.6	55.1	(1.5)	-3%
Asset Replacement				
Poles	76.1	36.5	(39.6)	-52%
Overhead Equipment	14.4	27.7	13.3	92%
Underground Equipment	21.6	32.1	10.5	49%
Trouble	17.7	20.1	2.4	14%
Asset Replacement sub-total	129.8	116.4	(13.4)	-10%
Beautification	1.1	4.8	3.7	333%
Total Sustain	187.5	176.2	(11.3)	-6%
Total Gross	487.5	515.9	28.4	6%
Less: Contribution in Aid	(134.0)	(161.1)	(27.1)	20%
Total	353.5	354.8	1.3	0%

**Table 18 Fiscal 2020 Distribution Capital Additions
Variances**

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	226.5	254.6	28.1	12%
System Expansion and Improvement	79.8	52.5	(27.3)	-34%
Uneconomic Extension Assistance	0.6	0.5	(0.1)	-15%
Total Growth	306.9	307.6	0.7	0%
Distribution Sustain				
System Expansion and Improvement	64.8	36.4	(28.4)	-44%
Asset Replacement				
Poles	75.9	56.3	(19.6)	-26%
Overhead Equipment	13.4	19.9	6.5	48%
Underground Equipment	22.5	28.7	6.2	28%
Trouble	17.6	20.1	2.5	14%
Asset Replacement sub-total	129.4	124.9	(4.5)	-3%
Beautification	1.1	0.7	(0.4)	-33%
Total Sustain	195.3	162.0	(33.3)	-17%
Total Gross	502.2	469.6	(32.6)	-6%
Less: Contribution in Aid	(131.0)	(137.5)	(6.5)	5%
Total	371.2	332.1	(39.1)	-11%

Distribution Growth – Customer Driven

Fiscal 2020 capital expenditures were \$47.1 million (or 20 per cent) above the Fiscal 2020 RRA Plan due to an increase in distribution customer driven extension activities, meter purchases for secondary connections, and the required design effort to support this increase. This work is difficult to plan as it is dependent on customer requests and their related timing.

Fiscal 2020 capital additions were \$28.1 million (or 12 per cent) above the Fiscal 2020 RRA Plan primarily due to the increase in capital expenditures discussed above.

Distribution Growth - System Expansion and Improvement

Growth-driven system expansion and improvement expenditures address existing capacity constraints to meet anticipated customer load growth. The priority of growth-driven system upgrades is influenced by new customer load connections and general load growth from existing customers. This category of expenditures is subject to year over year fluctuations from plan as a result of changes in scope, cost and schedule for projects as well as variances between forecast and actual customer load growth.

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were \$27.3 million (or 34 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The Bringing additional capacity from ARN to Tilbury (FV-FVW-057) project was \$18.8 million below plan because the project completion date was delayed to fiscal 2021 due to additional scope and time required to handle unfavorable site conditions encountered for the crossing under the Hwy 99;
- The WKA New Substation Bring 4 New Feeders (SI-KAM-001) project was \$10.7 million below plan due to a delay in the resolution of deficiencies and final contractor claims for the general contractor construction works. As a result of this delay, the project in-service date was deferred to fiscal 2021;
- The CBL New Feeder South Campbell River (VI-NVI-417) project was \$6.4 million below plan because the project was cancelled due to reduced load growth and a lower load forecast.

The decrease in capital additions above was partially offset by:

- The New Feeder to Bowen Island (LM-NSC-125) project was \$6.5 million above plan because the project in-service date was moved from previous fiscal years to fiscal 2020 due to additional time required for project closeout activities.

Distribution Sustain - System Expansion and Improvement

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and meeting regulatory, legal or environmental requirements.

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were \$28.4 million (or 44 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The H-Frame Elimination – Chinatown program of projects was \$12.4 million below plan as a result in changes in the project schedule affecting the timing of additions. The entire program of projects will be put in-service in fiscal 2021 instead of partially in fiscal 2020, as originally forecasted.;
- The Takla Landing (NI-NEW-287) project was \$8.4 million below plan because the project in-service date was delayed to fiscal 2022 as a result of project re-scoping; and
- The QNL Voltage Conversion (NI-NC-160) project was \$8.8 million below plan because the project in-service date was delayed to fiscal 2021 as a result of procurement delays.

Distribution Sustain - Asset Replacement

Distribution Asset replacements are planned and adjusted as an entire program based on inspections and changes in the prioritization of different assets.

Fiscal 2020 capital expenditures were \$13.4 million (or 10 per cent) below the Fiscal 2020 RRA Plan primarily due to lower volume of joint-use pole replacements and true-up of the third-party recoveries received.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

Contribution in Aid

Fiscal 2020 Distribution Contribution In Aid expenditures were \$27.1 million (or 20 per cent) above the Fiscal 2020 RRA Plan primarily due to higher than planned distribution customer driven extension activities.

Fiscal 2020 Distribution Contribution In Aid additions were comparable to the Fiscal 2020 RRA Plan.

10.5 Business Support Capital Expenditures and Additions Variance Explanations

Business Support includes capital expenditures and additions for Technology, Properties, Fleet, and Other categories. Business Support Fiscal 2020 capital expenditures and capital additions are presented by category in the tables below.

**Table 19 Fiscal 2020 Business Support Capital
Expenditures Variances**

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology	93.5	132.2	38.7	41%
Properties	58.9	56.4	(2.5)	-4%
Fleet	26.2	27.0	0.8	3%
Business Support - Other and Other Technology	39.5	32.8	(6.7)	-17%
Total	218.1	248.4	30.3	14%

Table 20 Fiscal 2020 Business Support Capital Additions Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology	141.0	93.7	(47.3)	-34%
Properties	40.0	44.3	4.3	11%
Fleet	26.2	29.2	3.0	12%
Business Support - Other and Other Technology	45.3	27.2	(18.1)	-40%
Total	252.5	194.4	(58.1)	-23%

Technology

Table 21 Fiscal 2020 Technology Capital Expenditures Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	93.5	132.2	38.7	41%
Total	93.5	132.2	38.7	41%

Table 22 Fiscal 2020 Technology Capital Additions Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	141.0	93.7	(47.3)	-34%
Total	141.0	93.7	(47.3)	-34%

Fiscal 2020 capital expenditures were \$38.7 million (or 41 per cent) above the Fiscal 2020 RRA Plan. This was primarily because:

- The terms of a software licensing contract changed from a perpetual license contract to a term subscription license. The subscription license costs of \$19.5 million were determined to be eligible for capitalization and recognized up-front for the full length of the contract. This resulted in an increase of \$17.5 million from the annual license fee of \$2.0 million, planned in each of the fiscal 2020 and fiscal 2021 in RRA under the original perpetual license contract.

-
- 1 • The Information Technology Service Management Toolset project was
2 \$11.8 million above plan as prepaid and future software subscription license
3 costs, which were expected to be operating costs, were determined to be
4 eligible for capitalization; and
 - 5 • The Supply Chain Applications project was \$7.5 million above plan due to
6 additional project code development build and testing activities to meet the
7 required quality standards.

8 Fiscal 2020 capital additions were \$47.3 million (or 34 per cent) below the
9 Fiscal 2020 RRA Plan. This was primarily because:

- 10 • The Supply Chain Applications project was \$57.4 million below plan primarily
11 due to the in-service date being delayed to fiscal 2021 as a result of a schedule
12 extension for the build and testing activities as well as a delay in the project
13 go-live training due to the COVID-19 pandemic;
- 14 • The End of Life Firewall Replacement project was \$3.6 million below plan
15 because the in-service date was delayed to fiscal 2021 due to a scope change
16 to include replacing the Calgary Internet Data Center (**CIDC**) edge firewalls in
17 the project, and the corresponding increase in time required for the technical
18 design in Definition phase;
- 19 • The Data Center Network Security Improvement project was \$2.5 million below
20 plan due to the in-service date being delayed to fiscal 2022 as a result of more
21 time required for technical design of the administrative access gateway solution
22 in the Definition phase; and

23 The decrease in capital additions outlined above was partially offset by the
24 increase of \$17.5 million in a software licensing agreement because the
25 subscription license costs of \$19.5 million were determined to be eligible for

capitalization and recognized up-front for the full length of the contract in fiscal 2020.

Properties

Table 23 Fiscal 2020 Properties Capital Expenditures Variances

Properties (\$ million)	F2020			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Interior Space Renovations	-	-	-	-
Building Development	37.8	14.7	(23.1)	-61%
Building Improvements and Others	21.1	40.7	19.6	93%
Other Properties	-	1.0	1.0	100%
Total	58.9	56.4	(2.5)	-4%

Table 24 Fiscal 2020 Properties Capital Additions Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Interior Space Renovations	-	-	-	-
Building Development	18.9	10.2	(8.7)	-46%
Building Improvements and Others	21.1	34.1	13.0	62%
Other Properties	-	-	-	-
Total	40.0	44.3	4.3	11%

Fiscal 2020 capital expenditures and capital additions for Properties were comparable to the Fiscal 2020 RRA Plan.

There were delays on the building development projects including:

- The Material Classification Facility Building Redevelopment project to allow for the Ministry of Environment approval of the Operations Plan for the new facilities; and
- The Chilliwack Facility Building Redevelopment project due to difficulties in securing suitable land for the new office.

As Properties manages the project portfolios on an overall basis to meet the annual plan, the impact of these delays was offset by the advancement of Building Improvement projects for generator equipment, property resurfacing and base building upgrades from future years.

Fleet

**Table 25 Fiscal 2020 Fleet Capital Expenditures
Variances**

Fleet (\$ million)	F2020			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Fleet	26.2	27.0	0.8	3%
Total	26.2	27.0	0.8	3%

**Table 26 Fiscal 2020 Fleet Capital Additions
Variances**

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Fleet	26.2	29.2	3.0	12%
Total	26.2	29.2	3.0	12%

Fiscal 2020 capital expenditures and capital additions for Fleet were comparable to the Fiscal 2020 RRA Plan.

Business Support - Other and Other Technology

**Table 27 Fiscal 2020 Business Support –Other and
Other Technology Capital Expenditures
Variances**

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support - Other	37.4	32.0	(5.4)	-14%
Other Technology	2.1	0.8	(1.3)	-60%
Total	39.5	32.8	(6.7)	-17%

**Table 28 Fiscal 2020 Business Support –Other and
Other Technology Capital Expenditures
Variances**

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support - Other	38.7	27.2	(11.5)	-30%
Other Technology	6.6	-	(6.6)	-100%
Total	45.3	27.2	(18.1)	-40%

Business Support - Other

Business Support – Other is comprised of capital expenditures such as security equipment, field tools and minor equipment. Fiscal 2020 capital expenditures for Business Support - Other were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions for Business Support - Other were \$11.5 million (or 30 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The completion and in-service date of the Security Command Center at South Interior Command Center project was delayed primarily due to vendors not meeting all the compliance requirements related to the North American Electric Reliability Corporation (**NERC**) Information Protection. In addition, there were schedule changes on smaller security projects which resulted in projects completion delays; and
- The completion and in-service dates for the Site Engineering and Acceptance projects were delayed to fiscal 2021 due to order delivery delays by the vendors.

Other Technology

Other Technology is comprised of the Mobile Radio Optimization project which was not classified as part of the main asset Technology category as the project was for Field Operations tools and equipment. Fiscal 2020 capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

10.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2020 capital expenditures and capital additions are presented in the tables below.

Table 29 Fiscal 2020 Site C Project Capital Expenditures Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	1,530.0	1,619.1	89.1	6%

Table 30 Fiscal 2020 Site C Project Capital Additions Variances

(\$ million)	F2020			
	Update	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	27.9	12.9	(15.0)	-54%

Fiscal 2020 capital expenditures were \$89.1 million (or 6 per cent) above the Fiscal 2020 RRA Plan. Variances were primarily due to:

- Spillway buttress construction activities were completed in fiscal 2020, ahead of plan;
- Higher than planned diversion tunnel work, and claims for main civil works;
- Work planned to be completed in prior years was completed in fiscal 2020;
- Additional change orders and claims for generating station and spillway; and
- Schedule advancement of highway early works and higher than planned worker accommodation and transmission expenditures.

The increase in capital expenditures above was partially offset by timing differences for turbines and generators, property acquisitions and reservoir clearing expenditures.

Further detail on the reasons for these variances are provided in BC Hydro's quarterly project reports to the BCUC.

Fiscal 2020 capital additions were \$15.0 million (or 54 per cent) below the Fiscal 2020 RRA Plan primarily due to the in-service date for the outdoor portion of the Peace Canyon Gas-Insulated Switchgear (part of the Transmission-related assets) being delayed to fiscal 2021.

11 Capital Projects and Programs: First Full Funding Amount vs Estimate at Completion

In compliance with BCUC Order No. G-313-19,¹ [Table 31](#) below provides a comparison of the First Full Funding (FFF) amount and estimate at completion (EAC) for all projects and programs of projects that meet the following criteria:

- Achieved final in-service date between April 1, 2019 and March 31, 2020; or final in-service date achieved prior to this fiscal year and where the remaining capital expenditures has increased 25 per cent or more and a minimum amount of \$0.5 million compared to the estimated remaining capital expenditures when previously reported;² and
- Met a materiality threshold of total capital expenditures of at least \$20 million for Power System and Building projects and programs, and \$10 million for Technology projects and programs. These align with the thresholds for inclusion in Appendix J in future revenue requirements applications; and

¹ [BCUC Order G-313-19](#) from the Review of the Regulatory Oversight of Capital Expenditures and Projects proceedings, page 27, "The final, actual cost for completed capital projects and programs above a materiality threshold."

² The increase of 25 per cent and a minimum amount of \$0.5 million compared to amounts previously reported criteria will be used going forward as this is the first time providing this report.

-
- 1 • Were not recurring projects and programs that were financially authorized at a
2 group, program or other aggregated level. This ensures consistency with the
3 information provided in the Attachment to Section 7.
- 4 [Table 31](#) includes the variance between the EAC³ and the FFF⁴ amount and
5 provides a brief explanation for any variance greater than or equal to 10 per cent.

³ The estimate at completion (**EAC**) is the forecast of capital expenditures for the project or program at financial close. It includes the actual capital cost of the project or program at the in-service date plus any estimated trailing costs to address deficiencies or to otherwise complete the project or program and achieve financial close.

⁴ The First Full Funding (**FFF**) amount includes actual capital expenditures incurred during the Identification and Definition Phases plus the estimate of capital expenditures for the Implementation Phase approved before the Implementation Phase. Approval of First Full Funding is required to start the Implementation Phase.

Table 31 Projects and Programs with Final In-Service Dates between April 1, 2019 to March 31, 2020

(\$ million)

A	B			C	D	E	F		G	H	I	J	K	
Planning ID	Name of Project	BCUC Application Reference -if applicable (Note 1)	F20-F21 RRA Appendix J Reference	Actual In-Service Date (Note 2)	Financially Closed (Note 3)	First Full Funding Amount (Note 4)	Appendix I Authorized Amount (Note 5)	BCUC Application Approved Amount (Note 1)	LTD Costs (Note 6)	Estimate At Completion (Note 7)	Variance [H-E]	Diff (%) [I/E]	Variance Explanation (>=10 percent)	BCUC Application Progress Reports Reference (Note 1)
G000492	Bridge River 2 Upgrade Units 5 and 6	N/A	Page 27	F2020	N	79.4	86.2	N/A	70.7	78.0	(1.4)	-2%		N/A
G000614	Cheakamus Units 1 and 2 Generator Replacement	N/A	Page 30	F2020	N	64.8	74.2	N/A	61.3	62.3	(2.4)	-4%		N/A
G003362	Mica Townsite Augment Accommodations Capacity	N/A	Page 36	F2020	N	22.1	23.3	N/A	21.6	22.0	(0.2)	-1%		N/A
G003542	Mica Upgrade Powerhouse Cranes	N/A	Page 37	F2020	N	32.4	36.1	N/A	27.4	28.6	(3.8)	-12%	Note A	N/A
YT-01082	Microsoft Enterprise Agreement 2019	N/A	N/A	F2020	Y	19.5	19.5	N/A	19.5	19.5	0.0	0%	Note B	N/A

Note 1 BCUC Application refers to CPCN or Section 44.2 Applications

Note 2 Actual in-service date refers to the final project in-service date achieved

Note 3 Financially closed is when the project has completed all project closing procedures, no additional incremental costs are expected, and project has been closed in the financial system

Note 4 First Full Funding refers to the total capital cost of the project (excluding project reserve) when it was first approved for full Implementation Phase by BC Hydro

Note 5 Authorized Amount refers to the total capital cost of the project, including project reserve, included in the F20-21 RRA Appendix I

Note 6 LTD costs refer to the life-to-date capital costs as of March 31, 2020

Note 7 Estimate at Completion refers to the forecasted capital cost when the project is expected to be financially closed

Note A The Mica Upgrade Powerhouse Cranes was \$3.8 million (or 12 per cent) below plan because the anticipated cost of major scaffolding requirements during the runway steel upgrade was not utilized due to the contractor being able to use a series of man lifts and cranes for the installation which resulted in cost savings.

Note B An update on this project was included in Exhibit B-29, which was filed on January 15, 2020 as part of the F2020–F2021 RRA proceedings.

**BC Hydro Fiscal 2022
Revenue Requirements Application**

Appendix Q

Fiscal 2021 BC Hydro Service Plan

BC Hydro and Power Authority

2020/21 – 2022/23 SERVICE PLAN

February 2020



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Board Chair Accountability Statement



The 2020/21 – 2022/23 BC Hydro Service Plan was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act*. The plan is consistent with government's strategic priorities and fiscal plan. The Board is accountable for the contents of the plan, including what has been included in the plan and how it has been reported. The Board is responsible for the validity and reliability of the information included in the plan.

All significant assumptions, policy decisions, events and identified risks, as of January 31, 2020 have been considered in preparing the plan. The performance measures presented are consistent with the *Budget Transparency and Accountability Act*, BC Hydro's mandate and goals, and focus on aspects critical to the organization's performance. The targets in this plan have been determined based on an assessment of BC Hydro's operating environment, forecast conditions, risk assessment and past performance.

A handwritten signature in black ink, which appears to read "K. Peterson". The signature is stylized with a large, sweeping initial "K" and a long, horizontal flourish extending to the right.

Kenneth G. Peterson
Board Chair

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Strategic Direction and Alignment with Government Priorities

The Government of British Columbia remains focused on its three strategic priorities: making life more affordable, delivering better services, and investing in a sustainable economy. Crown corporations are essential to achieving these priorities by providing quality, cost-effective services to British Columbia families and businesses.

Additionally, where appropriate, the operations of Crown corporations will contribute to:

- The objectives outlined in the government's newly released *A Framework for Improving British Columbians' Standard of Living*,
- Implementation of the *Declaration on the Rights of Indigenous Peoples Act* and the Truth and Reconciliation Commission Calls to Action, demonstrating support for true and lasting reconciliation, and
- Putting B.C. on the path to a cleaner, better future – with a low carbon economy that creates opportunities while protecting our clean air, land and water as described in the CleanBC plan.

By adopting the Gender-Based Analysis Plus (GBA+) lens to budgeting and policy development, Crown corporations will ensure that equity is reflected in their budgets, policies and programs.

BC Hydro is one of the largest electric utilities in Canada and is publicly owned by the people of British Columbia. We generate and provide electricity to 95 per cent of B.C.'s population and serve over four million people. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

Our mission is to safely provide reliable, affordable, clean electricity throughout B.C. We have set out a three-year plan with strategies, performance measures and targets, aligned with the objectives in the [B.C. Government's Mandate Letter to BC Hydro](#), to fulfill our mission on behalf of our customers and the Province.

We have the important responsibility to help keep electricity affordable for our customers, while funding necessary investments in our electricity system. To support this goal, we are implementing the outcomes from Phase 1 of the Comprehensive Review of BC Hydro and making all reasonable efforts to limit rate increases. We are actively participating in Phase 2 of the Comprehensive Review to create a strategy that enables BC Hydro to continue to provide our customers with clean, reliable electricity at competitive rates through our continuing evolution in response to changes in climate, consumer demand, technology and B.C.'s commitment to Indigenous Nations.

BC Hydro's electricity system was largely built in the 1960s, 1970s and 1980s, and B.C.'s population and economy continue to grow. BC Hydro is upgrading and maintaining aging assets and building new infrastructure so that our customers continue to receive reliable and clean electricity. To ensure sustained economic and social benefits for ratepayers, we manage our capital portfolio with an emphasis on cost consciousness, respect for the environment and communities in which we work, and in particular, strengthening our relationships with First Nations communities.

BC Hydro will continue making investments to expand the system and maintain aging infrastructure to meet our customers' growing needs and expectations, while managing our costs, helping keep electricity affordable for our customers and improving our service.

BC Hydro is aligned with the Government's key priorities:

Government Priorities	BC Hydro Aligns with These Priorities By:
Making life more affordable	Helping keep electricity bills affordable for our customers by managing our costs, exploring innovative solutions to support our customers and making cost-effective investments to maintain and expand our electricity system. (Objective 3.1)
Delivering the services people count on	Reliably meeting the electricity requirements of customers and responding to their evolving expectations by prudently planning and investing in the system to meet future needs, consistently improving our service and advancing reconciliation with Indigenous Peoples. (Objective 2.1)
A strong, sustainable economy	- Implementing our 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity. (Strategy under Objective 3.1) - Supporting the implementation of the CleanBC plan to increase British Columbians' use of cleaner energy in key sectors of the economy and shift away from reliance on fossil fuels for transportation, buildings and industry. (Strategy under Objective 4.1)

Operating Environment

As a utility that operates in a high hazard industry, we are committed to ensuring our workforce goes home safely every day and that the public is safe around our system. We are continuously working to improve our performance by understanding hazards, ensuring appropriate design of assets, related work procedures and competencies.

BC Hydro is regulated by the British Columbia Utilities Commission (BCUC). As the independent regulator of BC Hydro, the BCUC reviews BC Hydro's costs, proposed rate increases, integrated resource planning and almost all regulatory accounts, programs and capital projects. On February 25, 2019, BC Hydro submitted the Fiscal 2020-Fiscal 2021 Revenue Requirements Application to the BCUC, which reflects our efforts to continue to deliver safe and reliable power, while keeping electricity affordable for our customers.

We are also implementing the outcomes resulting from Phase 1 of the Comprehensive Review by making all reasonable efforts to limit rate increases and managing our costs. We are actively participating in Phase 2 of the Review, which will develop recommendations for how BC Hydro can accomplish the provincial policy objectives in [CleanBC](#), including support of British Columbia's legislated greenhouse gas reduction targets, in a manner that ensures BC Hydro's future sustainability for the benefit of British Columbians. The Review will consider the potential impacts of North American energy and market trends, the needs of current and future BC Hydro customers, evolving technologies and utility structures, the affordability of electricity to consumers, and opportunities to involve Indigenous Peoples and communities.

The electricity we generate and deliver throughout B.C. meets a high standard of reliability, but we are always looking for ways to improve our service to our customers and help power British Columbia's strong, sustainable economy.

BC Hydro is focused on delivering our renewed customer service strategy, with the goal of making it easier to do business with us and helping customers make smart energy choices through our conservation and energy management programs. We will also continue to advance affordability initiatives to help our customers save money on their electricity bills. To help advance the Province's [CleanBC](#) climate and economic development objectives, we are encouraging our customers to use our clean and reliable electricity to power their homes, vehicles and businesses in order to reduce greenhouse gas (GHG) emissions.

We continue to make significant investments to expand the system and maintain aging infrastructure, while prudently managing all costs to help keep electricity affordable for our customers. This includes the development of the Site C project. Over the past five years (2014/15-2018/19), we have delivered 426 capital projects at a total cost of \$8.03 billion, which is 0.34 per cent over budget overall, and well within BC Hydro's +5% to -5% target. We work across teams, suppliers and experts to ensure thoughtful assessment of how to successfully deliver these projects on time and on budget while respecting the unique community, environmental and Indigenous interests associated with each project.

Operating, maintaining and expanding BC Hydro's extensive electricity system impacts a significant number of Indigenous communities across the province. We continue to pursue meaningful, long-term relationships with Indigenous groups to better understand their interests so they can be incorporated in our planning and business operations. With the historic passing of the *Declaration on the Rights of Indigenous Peoples Act* in November 2019, BC Hydro is working to implement the United Nations Declaration on the Rights of Indigenous Peoples, the Calls to Action in the Truth and Reconciliation Report, and the Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples into our business.

With thoughtful planning and prudent decision-making, BC Hydro is well positioned to safely deliver clean, reliable, affordable, electricity throughout B.C., today and into the future.

Performance Plan

We have identified four key goals that reflect successful delivery of [our mission](#): our workforce and the public will be safe; customers will experience reliable and responsive service; we will help keep electricity bills affordable for our customers; and, we will help make renewable, clean electricity British Columbia's leading energy source.

These four key goals guide our actions, each supported by corresponding strategies, performance measures and targets. Each performance measure has a definition and rationale, as well as relevant benchmarking measures that allow a comparison of performance over time. These measures track our progress on delivering on our mission to our customers and the Province. BC Hydro's management is responsible for measuring performance against targets. Results are reported to the Board on a quarterly basis and publicly in the Annual Service Plan Report.

Goal 1: Safety Above All

Objective 1.1: Safety at BC Hydro is a core value. We are committed to ensuring our workforce goes home safely every day, and that the public is safe around our system.

Key Strategies:

- Form a strong partnership with operational teams to guide and assist them in creating and sustaining a safe work place.
- Implement an integrated and sustainable safety and health management system with defined processes, accountabilities and responsibilities to manage risk.
- Create a learning culture within BC Hydro by using incident and near miss data to inform improvements in work methods, training and safety programs.
- Continue to standardize and consolidate safety information in one location so employees are able to easily find and understand the rules, procedures and work methods they require to complete their work.
- Continue public education efforts on hazards associated with electricity.
- Protect the public from hazards around our reservoirs and dams through adherence to the Canadian Dam Association Public Safety Around Dams guidelines with controlled access to areas that can be kept safe.
- Develop safety analytic services that will assist the organization to turn data into actionable information that improves safety outcomes.

Performance Measure(s) ¹	2018/19 Actuals	2019/20 Forecast	2020/21 Target	2021/22 Target	2022/23 Target
1.a Zero Fatality & Serious Disabling Injury ² [Loss of life or the injury has resulted in a permanent disability]	0	0	0	0	0
1.b Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	0.87	0.80	0.80	0.76	0.74
1.c Timely Completion of Corrective Actions (%)	98	97	97	97	98

¹ Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance

² Zero Fatality and Serious Disabling Injury – BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

Linking Performance Measures to Objectives:

1.a Achieving our target of Zero Fatality and Serious Disabling Injury supports our objective that everyone goes home safely, every day.

1.b Lost Time Injury Frequency (LTIF) is an indicator of the likelihood of a full time employee sustaining a time loss injury in a normal work year and is a comparable metric to other provincial

organizations and the Canadian Electricity Association. LTIF of 1 equates to a 1 per cent chance of a time loss injury for any given employee in a work year.

1.c Timely Completion of Corrective Actions supports our strategy towards becoming a learning organization by addressing systemic improvements to our business to manage risk in a timely manner.

Discussion:

In 2020/21, BC Hydro will continue to utilize benchmark metrics such as Serious Incident and Fatality Frequency and LTIF to report on our ability to manage risk to workers and learning from previous incidents.

LTIF targets trending downwards illustrate the continual improvement we have made in controlling safety risks and mitigating hazards. The 2021/22 target has been modified to reflect a 5 per cent adjustment based on the updated 2019/20 forecasted result and the 2022/23 target has been set at a 2.5 per cent adjustment on the 2021/22 target.

Our Timely Completion of Corrective Actions targets trend upward to continue focusing on meeting the due dates of these actions. Results are reported using the definition of the measure introduced in the 2018/19 – 2020/21 Service Plan: the percentage of safety corrective actions closed on or before the scheduled due date on an annual basis, with an aim to improve over time. The 2020/21 target has been adjusted from 95 per cent to 97 per cent based on the updated 2019/20 forecasted result.

Goal 2: Set the Standard for Reliable and Responsive Service

Objective 2.1: BC Hydro will reliably meet the electricity requirements of customers and respond to their evolving expectations by prudently planning and investing in the system to meet future needs, consistently improving our service and advancing reconciliation with Indigenous Peoples.

Key Strategies:

- Ensure the reliability of the generation, transmission and distribution system by effectively implementing capital and maintenance programs to manage overall condition of the power system and ensure supply to meet customer load throughout the year.
- Continue to make it easier for customers to do business with us through a series of customer facing improvements such as: increased mobile access; enabling more self-service features; exploring new, innovative rate options; expanding in-person service areas; and enhancing customer service training for employees.
- Sustain gold-level certification under the Progressive Aboriginal Relations program by advancing practices in the areas of leadership, employment, business development and community relationships.
- Continue to advance reconciliation by incorporating the *Declaration on the Rights of Indigenous Peoples Act*, the Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples and the Calls to Action of the Truth and Reconciliation Commission into our business.
- Safeguard the system with risk-prioritized security solutions and prepare our operations with well-practiced emergency response plans to support system reliability.

Performance Measure(s) ¹	2018/19 Actuals	2019/20 Forecast	2020/21 Target	2021/22 Target	2022/23 Target
2.a SAIDI (System Average Interruption Duration Index) ² [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year (excluding major events)]	2.96	3.21	3.20	3.20	3.20
2.b SAIFI (System Average Interruption Frequency Index) ² [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.35	1.54	1.40	1.40	1.40
2.c Key Generating Facility Forced Outage Factor (%)	1.61	1.60	1.80	1.80	1.80
2.d CSAT Index ³ [Customer Satisfaction Index: % of customers satisfied or very satisfied]	87.7	87.0	85.0	85.0	85.0
2.e Progressive Aboriginal Relations Certification ⁴	Gold	Gold	Gold	Gold	Gold

¹ Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance

² Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the reliability projection modelling uncertainty, the wide range of variations in weather patterns and the uncontrollable elements that can significantly disrupt the electrical system. BC Hydro reports reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

³ Customer Satisfaction Index (CSAT) is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial and key accounts). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.

⁴ Progressive Aboriginal Relations is a certification program by the Canadian Council of Aboriginal Business.

Linking Performance Measures to Objectives:

2.a & 2.b Customer reliability is measured using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These, along with correlated cause analysis for customer outages, support targeted investment, planning and process improvements to meet our customers' needs for reliability.

By measuring the average number of service interruptions and number of hours of sustained interruptions experienced by the average customer in a year, we are able to track our ability to reliably meet the electricity requirements of customers.

2.c A forced outage occurs when a generating unit is unable to start generating or does not stay on line as long as needed. The Key Generating Facility Forced Outage Factor will show the trend of how the generation assets are performing and support investment decisions to maintain asset reliability.

2.d The Customer Satisfaction (CSAT) Index measures customer satisfaction with BC Hydro on five key drivers: value for money; commitment to customer service; providing reliable electricity; acting in the best interest of British Columbians; and efforts to communicate to customers and communities. This measure gauges the degree to which BC Hydro is meeting customers' electricity and service needs.

2.e The Canadian Council of Aboriginal Business's Progressive Aboriginal Relations (PAR) Gold certification offers validation of BC Hydro's sustained actions towards enhanced Indigenous relations. With BC Hydro's extensive footprint throughout the province, and our role as a Crown corporation, the comprehensiveness of the PAR certification acts as a measure for us to ensure relationships with Indigenous peoples are built on mutual respect and appropriately reflect the interests of Indigenous communities.

Discussion:

SAIDI and SAIFI targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans while also accounting for annual variability due to weather. Consistent focus on customer reliability has enabled the targets to remain stable at the 2020/21 levels to align with historical performance, trends resulting from investment, planning and ongoing process improvements.

There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200 MW¹. Together, they provide 90 per cent of the average annual electricity generated by BC Hydro's facilities. Key Generating Forced Outage Factor is reported as a five year rolling average and defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year). Annually, the Forced Outage Factor can be relatively volatile, and applying the historical five year rolling average smooths the range to provide a more stable measure for which targets can be set. The objective is to keep the Forced Outage Factor below 1.80 per cent of the total number of hours per year.

BC Hydro strives to provide high quality customer experience and must balance its investments with the need to maintain the affordability of its rates. The stable target for the CSAT index reflects that customers' service needs are generally being met; however, continued effort is necessary to address gaps in specific areas, as well as to meet customers' changing expectations from their interactions with other organizations. In the near-term BC Hydro does not have any planned investments that would result in a sustained increase to the index.

The Canadian Council of Aboriginal Business' PAR is a certification program designed to help Canadian businesses benchmark, improve and signal their commitment to progressive relationships with Indigenous communities, businesses and people. It evaluates four areas of performance including: leadership actions; employment; business development; and community relations. PAR certification provides a high degree of assurance to Indigenous communities, as certification every three years is supported by an independent third party verification and is determined by a jury comprised of Indigenous business people. BC Hydro has attained the highest, gold-level designation

¹ The Waneta Generating Station is not included in the Forced Outage Factor Performance Measure because BC Hydro does not manage or operate the facility.

from the Canadian Council for Aboriginal Business since 2012. In 2018/19, we were re-certified at the gold-level for a three year period.

Goal 3: Help Keep Electricity Bills Affordable for our Customers

Objective 3.1: BC Hydro will help keep electricity bills affordable for our customers by managing our costs, exploring innovative solutions to support our customers and making cost-effective investments to maintain and expand our electricity system.

Key Strategies:

- Advance affordability initiatives with the BCUC to help our customers manage their electricity bills.
- Submit Revenue Requirements Applications to the BCUC consistent with the rates forecast released in Phase 1 of the Comprehensive Review.
- Make all reasonable efforts to keep rates affordable by acting on the outcomes of Phase 1 of the Comprehensive Review, including strategies to reduce future energy procurement costs.
- Participate in Phase 2 of the Comprehensive Review, to create a strategy, for the benefit of British Columbians, for BC Hydro to continue to provide its customers with clean, reliable energy at competitive rates through its continuing evolution in response to changes in climate, consumer demand, technology and B.C.'s commitment to reconciliation with Indigenous Nations.
- Implement our 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity.
- Continue to refine and enhance our systematic and disciplined project delivery methodology to ensure that our projects are put into service safely, on time, on budget and to a high standard of quality.
- Under the oversight of the independent Project Assurance Board, complete the Site C Project on schedule and within the approved budget, with a particular focus on managing risks and cost pressures and continue to provide quarterly progress exception reporting.
- Improve how we operate by improving our processes and supply chain strategies.

Performance Measure(s) ¹	2018/19 Actuals	2019/20 Forecast	2020/21 Target	2021/22 Target	2022/23 Target
3.a Affordable Bills ²	1 st quartile	1 st quartile	1 st quartile	1 st quartile	1 st quartile
3.b Project Budget to Actual Cost ³	+0.34% on \$8.03 billion ⁴	-1.86% on \$7.23 billion ⁵	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

¹ Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance

² BC Hydro calculates a relative index for each usage level within the residential category and then calculates an average of the index to create an overall ranking based on Hydro Quebec's annual report on North American electricity rates. The

rankings of the 22 participating utilities are then allocated into quartiles. The 1st quartile ranking represents the six utilities that have the lowest monthly electricity bills on April 1 of a given year.

³This measure compares actual project costs at completion to the original approved full scope implementation budgets, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period.

⁴This represents projects that went into service for the five year period 2014/15 to 2018/19.

⁵This represents projects that went or are forecast to go into service for the five year period 2015/16 to 2019/20.

Linking Performance Measures to Objectives:

3.a The Affordable Bills measure is based on BC Hydro's ranking in the residential rates category in the annual Hydro Quebec report, [Comparison of Electricity Prices in Major North American Cities](#). The report is used as a benchmark to demonstrate that our bills are affordable compared to other major North American utilities.

3.b Since 2015/16, BC Hydro has utilized the Project Budget to Actual Cost measure for the delivery of capital projects, with a target of actual project costs to be within +5 per cent to -5 per cent of the budget, excluding project reserves at the portfolio level. The +/- 5 per cent target is the same over the plan period, as it is the objective to have the entire project portfolio in-service within this actual cost range. BC Hydro has consistently met this performance target, as we continue to prudently manage capital expenditures and keep rates affordable for our customers.

Discussion:

BC Hydro's residential bills have consistently been ranked in the first quartile over the past ten years. This year we are ranked third place within the first quartile based on analysis of the 2019 Hydro Quebec report, [Comparison of Electricity Prices in Major North American Cities](#).

The Project Budget to Actual Cost measure includes Dam Safety, Generation, Transmission Line, Substation and large Distribution projects, managed by BC Hydro Capital Infrastructure Project Delivery and Properties for the last five years. Annually, BC Hydro reports the past five years' performance at the portfolio level in delivering capital projects.

Goal 4: Help Make Renewable, Clean Power British Columbia's Leading Energy Source

Objective 4.1: BC Hydro will strengthen its legacy of renewable, clean power and conservation investments through its energy-efficiency and conservation programs and support for low-carbon electrification.

Key Strategies:

- Support the implementation of the CleanBC plan to increase British Columbians' use of clean energy in key sectors of the economy and shift away from reliance on fossil fuels for transportation, buildings and industry.
- Support customers with initiatives and rate structures that help them make smart energy management choices through our energy management initiatives (e.g. energy efficiency and conservation programs) and low carbon electrification initiatives.
- Implement our energy conservation and energy management plan, which will exceed the *Clean Energy Act* requirement to meet at least two-thirds of future demand growth by 2020.
- Provide customers with the opportunity to access clean, renewable power to displace the use of higher carbon energy sources.

- As part of the CleanBC plan, partner with the Province and the federal government to implement the Remote Community Energy Strategy to help remote communities, with a focus on Indigenous communities, reduce or eliminate diesel generation and replace it with energy from cleaner sources.

Performance Measure(s) ¹	2018/19 Actuals	2019/20 Forecast	2020/21 Target	2021/22 Target	2022/23 Target
4.a Energy Conservation Portfolio (New incremental GWh/year) ²	868	734	700	500	500
4.b Clean Energy (%)	97.4 ³	96.4	93.0	93.0	93.0

¹ Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

² Annual targets are part of a Demand Side Management Plan that is set to fulfill the *Clean Energy Act* requirement to meet at least two-thirds of future demand growth by 2020. BC Hydro's future targets will be informed by the 2021 Integrated Resource Plan.

³ Previously reported at 97.8 in the 2018/19 Annual Service Plan Report. Prior years' results were calculated based on the latest available data and may be different than previously stated.

Linking Performance Measures to Objectives:

4.a The Energy Conservation Portfolio performance measure reflects new incremental energy savings from programs, codes and standards and conservation rates that measure BC Hydro's performance against annual energy targets. This measures the success of BC Hydro's planned conservation targets. Targets are rounded values and considered to be achieved if performance is within 10 per cent of the stated values.

4.b The Clean Energy performance measure demonstrates BC Hydro's efforts to generate clean, sustainable, affordable electricity in order to reduce GHG emissions in the province and continue to meet the 93 per cent minimum clean energy objective in the *Clean Energy Act*. The higher the per cent clean energy that BC Hydro achieves, the lower the GHG emissions in the province.

Discussion:

The targets for Energy Conservation Portfolio are based on BC Hydro's forecast of annual new incremental energy savings and do not reflect past performance and/or adjustments made to energy savings in prior years (e.g., persistence, evaluations, measurement and verification). In some cases, the timing of savings for anticipated codes and standards and timing of large customer projects can shift, which will cause actual incremental energy savings to vary from the targets that have been set for the period.

The Clean Energy performance measure represents the minimum threshold generation output in accordance with the B.C. Government's requirement that at least 93 per cent of electricity generation in the province be from clean or renewable resources, as specified in the *Clean Energy Act*. While actual output of the non-clean resources in the system supports system reliability and can vary depending on market conditions and water inflows to our reservoirs, BC Hydro expects that the actual performance will remain close to 98 per cent.

Financial Plan

Summary Financial Outlook

Consolidated Statement of Operations¹ (\$ millions)	2019/20 Forecast	2020/21 Budget	2021/22 Budget	2022/23 Budget
Domestic	5,459	5,670	5,719	5,838
Trade	665	786	817	832
Total Revenues	6,124	6,456	6,536	6,669
Operating Costs				
Cost of energy	2,225	2,284	2,435	2,510
Personnel expenses, materials & external services²	1,219	1,239	1,243	1,248
Amortization	989	1,006	1,028	1,019
Grants and taxes	261	271	285	295
Finance charges	1,177	706	627	601
Other	124	88	89	107
Total Expenses	5,994	5,594	5,706	5,779
Net Income before movement in regulatory balances	130	862	830	890
Net movement in regulatory balances	577	(150)	(118)	(178)
Net Income	707	712	712	712
Other Selected Financial Information:				
Dividends	-	-	-	-
Net Debt³	23,445	24,731	25,871	26,886
Equity	5,654	6,366	7,078	7,790
Capital Expenditures	3,045	3,092	2,970	2,905

¹ Table may not add due to rounding.

² These amounts are net of capitalized overhead and consist of the following:

	<u>2019/20</u>	<u>2020/21</u>	<u>2021/22</u>	<u>2022/23</u>
Domestic Base Operating Costs	794	805	831	839
Other	425	434	412	409
	<u>1,219</u>	<u>1,239</u>	<u>1,243</u>	<u>1,248</u>

Other largely consists of Powerex & Powertech operating costs, IFRS-ineligible capital overhead that is being phased into operating costs over a 10-year period, and expenses subject to regulatory deferral.

³ Debt figures are net of sinking funds and cash and cash equivalents.

Key Forecast Assumptions, Risks and Sensitivities

Key Assumptions	2019/20 Forecast	2020/21 Budget	2021/22 Budget	2022/23 Budget
Growth and Load				
B.C. Real Gross Domestic Product Growth (%) ¹	2.4	2.3	2.1	2.0
Domestic Sales Load Growth (%) ^{2, 3}	(0.14)	2.52	(0.97)	1.31
Load and Surplus Sales:				
Domestic Sales Volume (GWh)	52,337	53,656	53,138	53,833
Surplus Sales Volume (GWh)	182	3,032	3,463	2,633
Line Loss and System Use (GWh)	4,991	5,594	5,552	5,533
Total Load and Surplus Sales (GWh)	57,511	62,281	62,153	61,998
Energy Generation				
Total System Water Inflows (% of average)	93	100	100	100
Sources of Supply:				
Net Hydro Generation (GWh)	37,483	46,614	45,376	44,945
Market Electricity Purchases (GWh)	5,071	436	410	596
Independent Power Producers and Long-term Purchases (GWh)	14,674	14,933	16,036	16,124
Thermal Generation & Other (GWh)	283	298	332	333
Sources of Supply (GWh)	57,511	62,281	62,153	61,998
Average Mid-C Price (U.S.\$/MWh)	25.98	27.67	30.45	31.13
Average Natural Gas Price at Sumas (U.S.\$/MMBTU)	2.65	2.16	2.13	2.12
Financial				
Canadian Short-Term Interest Rates (%) ⁴	1.63	1.47	1.82	2.32
Canadian Long-Term Interest Rates (%) ⁴	2.18	2.43	2.77	3.40
Foreign Exchange Rate (U.S.\$:Cdn\$) ⁴	0.7559	0.7616	0.7650	0.7714

¹ Economic assumption based on calendar year, from Ministry of Finance February Budget 2019.

² Includes the impact of Demand Side Management programs.

³ Excludes surplus sales.

⁴ Financial assumptions from Ministry of Finance, October 2019.

Sensitivity Analysis

Factor	Change	Approximate change in 2020/21 earnings before regulatory account transfers (in \$ millions)
Customer Load ¹	+/- 1%	35
Interest Rates ²	+/- 100 basis points	30
Electricity/Gas trade margins ³	+/- 10%	25
Hydro Generation (GWh) ⁴	+/- 1%	10
Exchange rates (US/ CDN)	+/- \$0.01	5

¹Assumes a percentage change is applied equally to all customer classes. Assumes a change in customer load is offset by a corresponding change in market electricity purchases or surplus sales.

²Relates to debt subject to interest rate variability.

³Trade revenues less trade energy costs.

⁴Assumes a change in hydro generation is offset by a corresponding change in market electricity purchases or surplus sales.

Management's Perspective on the Financial Outlook

In February 2019, BC Hydro filed an application with the BCUC for its revenue requirements for a two-year test period covering 2019/20 and 2020/21. In August 2019, BC Hydro provided an Evidentiary Update to its application. BC Hydro expects a decision in spring 2020 which may change the financial projections for revenues and expenses.

The current financial projections for revenues and expenses through 2022/23 were approved by the BC Hydro Board of Directors and submitted to the Ministry of Finance in January 2020.

This plan contains forward looking statements, including statements regarding the business and anticipated financial performance of BC Hydro. These statements are subject to a number of risks and uncertainties such as customer load, interest rates, electricity/gas market conditions and our ability to deliver our capital projects on-time and on-budget. These and other risks and uncertainties may cause actual results to differ from those contemplated in the forward-looking statements.

Major Capital Projects

Capital Expenditure by Year and Type and Function

(\$millions)	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast
Capital Expenditures by Type¹				
Sustaining	964	1,004	1,146	1,259
Growth	2,081	2,088	1,824	1,646
Subtotal – BC Hydro Capital Expenditures before CIA	3,045	3,092	2,970	2,905
Contributions-in-Aid (CIA) ²	(169)	(160)	(214)	(167)
Total – BC Hydro Capital Expenditures net of CIA	2,876	2,932	2,756	2,738
Generation	283	351	388	427
Transmission and Distribution	919	891	995	1,091
Properties, Technology and Other	249	224	226	210
Site C Project	1,594	1,626	1,361	1,177
Subtotal – BC Hydro Capital Expenditures before CIA	3,045	3,092	2,970	2,905
CIA	(169)	(160)	(214)	(167)
Total BC Hydro Capital Expenditures net of CIA	2,876	2,932	2,756	2,738

¹. BC Hydro classifies capital expenditures as either sustaining capital or growth capital:

- Sustaining capital includes expenditures to ensure the continued availability and reliability of generation, transmission and distribution facilities. It also includes expenditures to support the business, such as vehicles and information technology.
- Growth capital includes expenditures to meet customer load growth and other business investments. Growth capital includes expenditures to expand existing generation assets as well as expand and reinforce the transmission and distribution system, and includes Site C.

². Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity.

Projects over \$50 million

BC Hydro has the following projects, each with capital costs expected to exceed \$50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors.

Major Capital Projects (over \$50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2019 (\$ millions)	Estimated Cost to Complete (\$ millions)	Approved Anticipated Total Capital Cost of Project (\$ millions)
Projects Recently Put Into Service				
Horne Payne Substation Upgrade Project This project expanded the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated feeder sections, and a new control building. This project increased the firm capacity of the substation, added needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allowed for the implementation of an open-loop distribution system.	2019 In-Service	\$69	\$1	\$70
John Hart Generating Station Replacement This project replaced the existing six-unit 126 MW generating station (in operation since 1947) and added integrated emergency bypass capability to ensure reliable long-term generation and mitigated earthquake risk and environmental risk to fish and fish habitat. <i>*John Hart forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral.</i>	2019 In-Service	\$974	\$6	\$980*
Cheakamus Unit 1 and Unit 2 Generator Replacement This project replaced the two generators at Cheakamus generating station (in operation since 1957), addressed their poor condition and known deficiencies, and increased the capacity of each unit from 70 MW to 90 MW.	2019 In-Service	\$61	\$1	\$62

Major Capital Projects (over \$50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2019 (\$ millions)	Estimated Cost to Complete (\$ millions)	Approved Anticipated Total Capital Cost of Project (\$ millions)
Projects Recently Put Into Service				
Bridge River 2 Units 5 and 6 Upgrade Project This project replaced the two generators and other related equipment at Bridge River 2 and restored the historical operating capacity. These two generator units were placed in service in 1960 and were in unsatisfactory condition and unreliable.	2019 In-Service	\$68	\$10	\$78
Ongoing				
South Fraser Transmission Relocation Project* This project is intended to relocate certain sections of two 230kV transmission circuits (Circuit 2L62 and Circuit 2L58) from their present location adjacent to Highway 99 and in the George Massey tunnel to accommodate the replacement of the tunnel. These two 230kV circuits form a critical part of BC Hydro's transmission network supplying power to customers in Richmond, Delta and the Greater Vancouver area. <i>*Construction work on the South Fraser Transmission Relocation project is currently suspended pending the government's review of the George Massey Tunnel replacement.</i>	TBD	\$30	\$46	\$76
Downtown Vancouver Electricity Supply: West End Strategic Property Purchase This project is to acquire property rights to build and connect a new underground substation that will upgrade the aging electricity system in downtown Vancouver.	2020 Targeted In-Service	\$67	\$14	\$81

Major Capital Projects (over \$50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2019 (\$ millions)	Estimated Cost to Complete (\$ millions)	Approved Anticipated Total Capital Cost of Project (\$ millions)
Fort St. John and Taylor Electric Supply This project will maintain adequate supply capability, reduce line losses and improve reliability to the loads in the Fort St. John and Taylor areas by re-terminating 138kV transmission lines at the new Site C switchyard, and the addition of a 75 MVA transformer and new feeder positions.	2020 Targeted In-Service	\$44	\$9	\$53
UBC Load Increase Stage 2 Project This project is on behalf of BC Hydro's customer, the University of British Columbia, to continue to reliably meet the growing electricity needs of its Point Grey campus and the surrounding community.	2021 Targeted In-Service	\$33	\$22	\$55
Peace Region Electricity Supply (PRES) Project This project is needed to provide sufficient transmission system capacity to serve load growth and increase the reliability of electricity supply to existing customers in the South Peace. This project will facilitate reductions in provincial greenhouse gas emissions by enabling electrification of natural gas production, processing, and compression. <i>*The total cost represents the gross cost of the project and has not been netted for Federal Government contributions.</i>	2021 Targeted In-Service	\$131	\$154	\$285*
LNG Canada Load Interconnection Project This project is to facilitate the interconnection of LNG Canada's facility. A new double circuit 287kV transmission line will be constructed from Minette Substation (MIN) to LNG Canada's facility and system reinforcements at MIN will also be implemented. Under BC Hydro's standard tariffs, the customer is required to pay for a portion of this project's costs. <i>*The total cost represents the gross cost of the project and has not been netted for a customer's contribution of \$24M.</i>	2021 Targeted In-Service	\$29	\$53	\$82*

Major Capital Projects (over \$50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2019 (\$ millions)	Estimated Cost to Complete (\$ millions)	Approved Anticipated Total Capital Cost of Project (\$ millions)
Bridge River 2 Upgrade Units 7 and 8 Project This project will replace the two generators and other related equipment to restore the historical operating capacity. Units 7 and 8 were placed into service in 1960, are unreliable and in poor and unsatisfactory condition.	2021 Targeted In-Service	\$13	\$73	\$86
Wahleach Refurbish Generator Project This project will improve the reliability of the generator at Wahleach Generating Facility, and its scope includes replacement of the stator and rotor poles, refurbishment of the remaining major components, and a combination of new, replacement, and refurbishment of the auxiliary components. The project also includes the installation of a new powerhouse crane and structural upgrades to the powerhouse building.	2021 Targeted In-Service	\$12	\$39	\$51
Mica Replace Units 1 to 4 Generator Transformers Project This project will address the reliability and safety risks of the Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station, which are nearing end of life. There is a heightened reliability and safety risk from continuing to operate these transformers in an underground powerhouse as they age.	2022 Targeted In-Service	\$33	\$49	\$82

Major Capital Projects (over \$50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2019 (\$ millions)	Estimated Cost to Complete (\$ millions)	Approved Anticipated Total Capital Cost of Project (\$ millions)
G.M. Shrum G1 to 10 Control System Upgrade This project will replace the controls equipment, provide full remote control capability from the remote control center, and rectify deficiencies in the current system. The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of available spare parts and decreasing reliability. The controls are well beyond their expected life, which causes operating problems and increases the risk of damage to major equipment.	2022 Targeted In-Service	\$41	\$34	\$75
Mount Lehman Substation Upgrade Project This project will increase the firm capacity of the Mount Lehman Substation to address safety and asset health concerns at both the Clayburn and Sumas Way substations.	2022 Targeted In-Service	\$5	\$54	\$59
Capilano Substation Upgrade Project This project will address the existing asset health, reliability, safety, and environmental issues associated with the Capilano Substation, and to ensure that the capacity of the substation meets the long term area needs. The project will also introduce a 25kV source to enable 25kV voltage conversion and facilitate the execution of other future substation projects in the North Shore area.	2024 Targeted In-Service	\$6	\$81	\$87
Sperling Substation (SPG) Metalclad Switchgear Replacement Project This project will address the existing asset health, reliability and safety risks associated with the 12kV 60 series feeder section and the bulk oil breaker in the 12 kV 70/80 series feeder section, insufficient electrical clearances in the 60 series feeder section, and arc flash safety risks associated with the 12kV indoor metalclad switchgear.	2024 Targeted In-Service	\$2	\$52	\$54

Major Capital Projects (over \$50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2019 (\$ millions)	Estimated Cost to Complete (\$ millions)	Approved Anticipated Total Capital Cost of Project (\$ millions)
Site C Project This project will construct a third dam and a hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. <i>*Planned in-service date for all units.</i> <i>**Site C forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. The amount includes a reserve of \$708 million.</i>	2024* Targeted In-Service	\$4,691	\$6,009	\$10,700**

Significant Information Technology (IT) Projects over \$20 million

BC Hydro has the following IT project with capital costs expected to exceed \$20 million. This project has been approved by the Board of Directors.

Significant IT Projects (over \$20 million in total)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2019 (\$ millions)	Estimated Cost to Complete (\$ millions)	Approved Anticipated Total Capital Cost of Project (\$ millions)
Ongoing				
Supply Chain Applications Project This project will replace BC Hydro's existing PassPort supply chain information technology (IT) system with an SAP-based IT system and make improvements to BC Hydro's supply chain business processes for third-party materials and service acquisitions. <i>*The BCUC issued an Order, dated April 9, 2019, which accepted the expenditures to complete the Implementation Phase of the project.</i>	2020 Targeted In-Service	\$54	\$14	\$68*

Appendix A: Hyperlinks to Additional Information

Corporate Governance

Information about Corporate Governance can be found at:

http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding, and includes all information detailed in the Best Practice Guidelines: Governance and Disclosure Guidelines for Governing Boards of British Columbia Public Sector Organizations:

- Board of Directors
- Executive Team
- Code of Conduct
- Board Governance Manual

Organizational Overview

Information about BC Hydro's organizational overview can be found at:

<https://www.bchydro.com/toolbar/about.html>

This includes links to information about BC Hydro's operations, governance and mandate.

Appendix B: Subsidiaries and Operating Segments

As wholly-owned subsidiaries, and like BC Hydro itself, Powerex Corp. and Powertech Labs Inc. follow best practices in corporate governance and subsidiary activities align with BC Hydro's mandate, strategic priorities and fiscal plan.

Powerex Corp.

Powerex Corp., an energy marketer, is a wholly-owned corporate subsidiary of BC Hydro and a key participant in wholesale energy markets across North America. Powerex's business consists of trading wholesale power and natural gas, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), ancillary energy services, and financial energy products.

Through its contractual agreements with BC Hydro, Powerex supports BC Hydro's system requirements by importing and exporting energy. Powerex also markets, through a contractual agreement with the Province, the Canadian Entitlement to the Downstream Power Benefits under the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex. The Chair of the Powerex Board ensures the Board of BC Hydro is informed of Powerex's key strategies and business activities. The Powerex CEO also informs the BC Hydro President & CEO and Executive Team of Powerex's key strategies and business activities.

Powerex operates in competitive and complex wholesale energy-markets, which can cause net income in any given year to vary significantly. Market, economic and weather conditions, reduced hydro system flexibility, unrealized mark-to-market gains or losses and the strength of the Canadian dollar can materially impact Powerex net income. The Service Plan forecast includes annual net income from Powerex of approximately \$180 million per year for 2020/21 to 2022/23, based on the average earnings over the last five fiscal years. For more information, visit powerex.com

Board of Directors:

- Ken Peterson – Chair
- Len Boggio
- James Hatton
- Valerie Lambert
- Chris O'Riley

Powertech Labs Inc.

Powertech Labs Inc., operating in Surrey since its inception in 1979, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as holding expertise in a range of fields related to the electrical industry and offers services and products including: research and development, testing, technical services, software and advanced technology services to energy clients, including BC Hydro, and other sectors globally.

The President and CEO of Powertech reports to the BC Hydro President and CEO. The Powertech Board is chaired by BC Hydro's President and CEO and its Directors include senior Executives of BC Hydro.

The Service Plan forecast includes annual net income from Powertech of approximately \$4 million per year for 2020/21 to 2022/23. For more information, visit powertechlabs.com.

Board of Directors:

- Chris O'Riley - Chair
- Melissa Holland
- Kip Morison
- David Wong

Other Subsidiaries

BC Hydro has created or retained a number of other subsidiaries for various purposes, including holding licences in other jurisdictions, to manage real estate holdings and to manage various risks.

All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd.

Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd.

Administers and supplies the labour force to specified projects.

Tongass Power and Light Company

Provides electrical power to Hyder, Alaska from Stewart, B.C. due to its remoteness from the Alaska electrical system.

Nominee Holding Companies and/or Inactive/Dormant Subsidiaries

BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of December 31, 2019, these other subsidiaries consisted of the following:

1. British Columbia Hydro International Limited
2. British Columbia Power Exchange Corporation
3. British Columbia Power Export Corporation
4. British Columbia Transmission Corporation
5. Columbia Estate Company Limited*
6. Edmonds Centre Developments Limited*
7. Fauquier Water and Sewerage Corporation
8. Hydro Monitoring (Alberta) Inc.*
9. Victoria Gas Company Limited
10. Waneta Holdings (US) Inc.*
11. 1111472 BC Ltd.

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix R Maintenance

The material included in this Appendix remains applicable to the Fiscal 2022 Test Period. Text and data / tables that are no longer relevant have been removed and denoted with ellipses.

5.8.2 The Budget for Asset Maintenance Must Address Preventative, Condition-Based and Corrective Maintenance

When developing a budget for maintenance work, we must account for three broad categories of maintenance, which are summarized in [Figure 5-19](#) below. All of these activities are essential for the Power System to function safely and reliably.

Figure 5-19 Maintenance Work Types

Preventative	Condition-Based	Corrective
- Inspections, testing, calibration, and condition assessments - Planned Work	- Prioritized work based on current condition - Repair or replace in-service assets - Planned Work	- In-service asset damage or failure - Emergent work

The Power System asset maintenance programs also include two additional work categories which are required for safe and reliable asset operation:

- **Facility Maintenance:** work required to maintain the facilities and properties associated with the Power System. This includes items such as roofs, roads, fences, landscaping and snow removal; and
- **Engineering Services:** engineering support required for equipment maintenance. This includes activities such as developing and updating maintenance standards as well as performing failure investigations or specialized inspections or testing.

5.8.3 Determining the Appropriate Maintenance Investment Level Requires Consideration of Many Factors

While the trigger for spending on corrective maintenance - a failure or an emergent issue – is generally intuitive, the timing and prioritization of preventative and condition-based maintenance considers a number of factors.

- **Timing of preventative maintenance:** The frequency and timing of preventative maintenance activities are determined by factors such as asset criticality, component age and current condition, component failure modes,

failure costs, and the duration required for repairs in the case of failure. Preventive maintenance programs are also influenced by manufacturers' recommendations, regulatory requirements, engineering judgement, field experience, historical reviews, and industry practices. As a result, preventative maintenance requirements and frequencies are cyclical and can vary by asset, which means that preventative maintenance work is not uniform year over year.

- **Timing and prioritization of condition-based maintenance:** The majority of condition-based maintenance work consists of annually planned repairs or replacements of defective or damaged components of the system and occurs before equipment fails. Condition-based maintenance is triggered by the condition of equipment as determined by preventative maintenance inspections, tests, maintenance standards, manufacturer notices and/or operational readings or alarms. Condition-based maintenance is prioritized based on risk, considering factors such as asset criticality, component age and condition, and the consequence of failure. These considerations are analysed to determine when work should be undertaken or if the component condition should continue to be monitored.

5.8.4 BC Hydro Conducts Maintenance Activities on a Broad Range of Assets

BC Hydro's maintenance activities are categorized into line asset maintenance, stations asset maintenance and distribution emergency response. ...

5.8.4.1 Line Asset Maintenance Expenditures

...

- **Transmission Maintenance:** Annual transmission maintenance expenditures are primarily made up of transmission line maintenance and transmission vegetation management:
 - ▶ Transmission line maintenance includes inspecting and assessing the transmission system, test and treat inspections of wood poles as well as performing planned and unplanned repairs. All transmission structures are inspected at least once a year; and
 - ▶ Transmission vegetation management is required to manage vegetation along transmission corridors so that the system is reliable and safe and so that BC Hydro is in compliance with regulatory requirements.
- **Distribution Maintenance:** Annual distribution maintenance expenditures are made up of distribution line maintenance, distribution vegetation management and distribution meter maintenance:
 - ▶ Distribution line maintenance includes inspections and repairs of the overhead and underground system, test and treat inspections of wood poles as well as inspections and repairs of distribution assets such as manholes, cables, reclosers and voltage regulators and switches;
 - ▶ Distribution vegetation management includes routine maintenance to prune trees growing in proximity to power lines to reduce outages and damage caused by trees falling onto the distribution system; and

► Distribution meter maintenance includes programs to sample and test meters and exchange failed and time-expired meters, so that BC Hydro is in compliance with the requirements of the *Electricity and Gas Inspection Act* and with Measurement Canada's sampling regulations.

- **Telecommunications Protection and Control Maintenance:** Protection and control assets protect energized transmission equipment from being damaged from unplanned electrical events. They also provide system stability and reliability during disturbances, assist with the control of energy flows throughout the electrical grid and provide information to control centres through an integrated telecommunications system. Also included in this category are maintenance expenditures related to smart metering infrastructure telecommunications. These assets are maintained through a combination of preventative, condition-based and corrective maintenance work.

5.8.4.2 Stations Asset Maintenance Expenditures

...

- **Generation Maintenance:** BC Hydro's generation assets include 83 generating units at 30 hydroelectric generating facilities as well as 81 dams located at generating stations and at additional locations to provide water storage and water diversion functions. Generation assets also include three gas fired units at BC Hydro's two thermal generating stations and four synchronous condenser units at a dedicated synchronous condenser station. These assets are maintained through a combination of preventative, condition-based, corrective, and facility maintenance work;

- 1 • **Substations Maintenance:** BC Hydro has over 300 transmission and
2 distribution substations across the province. Substations are maintained to
3 minimize the lifecycle cost of the equipment, support safe and reliable
4 operation, and mitigate environmental impacts. These assets are maintained
5 through a combination of preventative, condition-based, corrective, and facility
6 maintenance work; and
- 7 • **Non-Integrated Area Maintenance:** BC Hydro has 17 diesel generating
8 stations and one hydroelectric generating station in areas not connected to the
9 integrated electric system. Maintenance on these assets consists of routine,
10 scheduled and corrective work.

11 **5.8.4.3 Distribution Emergency Response Maintenance Expenditures**

...

- 14 • **Routine Trouble** refers to maintenance expenditures for day-to-day restoration
15 of power outages.
- 16 • **Storm** refers to maintenance expenditures for events causing outages over a
17 large geographic area, affecting a large number of customers or of extended
18 duration. As discussed in section [5.5.2.2](#) above, BC Hydro continues to budget
19 for storm restoration costs using a five-year average of normal weather years.
20 In recent years, we have experienced higher levels of storm related damage,
21 which has caused the five year average of storm restoration costs to increase.
22 Variances between planned and actual storm restoration costs are deferred to

-
- 1 the Storm Restoration Costs Regulatory Account, which is discussed in
- 2 Chapter 7, section 7.8.1.
- 3 • **Damage to Plant** refers to events where a third-party may be liable for the cost
- 4 of system repairs. These costs are partially offset by miscellaneous revenues.

...

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix S

Capital Planning and Delivery Processes

The material included in this Appendix remains applicable to the Fiscal 2022 Test Period. Text and data / tables that are no longer relevant have been removed and denoted with ellipses.

6.3 BC Hydro's Capital Investment Planning Process

This section describes BC Hydro's enterprise wide capital planning process for capital investments and how this process was applied to create the Capital Plan that forms the basis for the capital-related evidence contained in this application.

BC Hydro has planning and governance processes in place across the organization so that the capital investments required to sustain, expand and operate its assets appropriately balance affordability and system performance.

This section is organized around the following points:

- Section [6.3.1](#): BC Hydro's Enterprise Capital Planning Process facilitates the use of a common approach to planning, prioritizing and governing investments across the company.
- Section [6.3.2](#): BC Hydro's Executive Team sets the strategic direction and priorities for the annual capital planning process.
- Section [6.3.3](#): A bottom up planning process is used for each of the asset categories.
- Section [6.3.4](#): BC Hydro uses a collaborative approach to review the capital portfolios across the enterprise and to develop the Capital Plan.
- Section [6.3.5](#): BC Hydro has robust processes for the governance, oversight and ongoing management of the Capital Plan.

6.3.1 The Enterprise Capital Planning Process Facilitates a Common Approach Across the Company

In 2017, BC Hydro established an Enterprise Capital Planning Working Group. The purpose of the Enterprise Capital Planning Working Group is to apply a common approach to planning, prioritizing and governing investments across the company.

6.3.1.1 *There is Now a Dedicated Working Group With Responsibility for Planning Approach*

The Enterprise Capital Planning Working Group includes representatives of all of the KBUs with responsibility for capital investment: Dam Safety, Stations Asset Planning, Lines Asset Planning, Energy Planning and Analytics, Properties, Technology, Finance KBUs, as well as the Fleet department of the Supply Chain KBU.

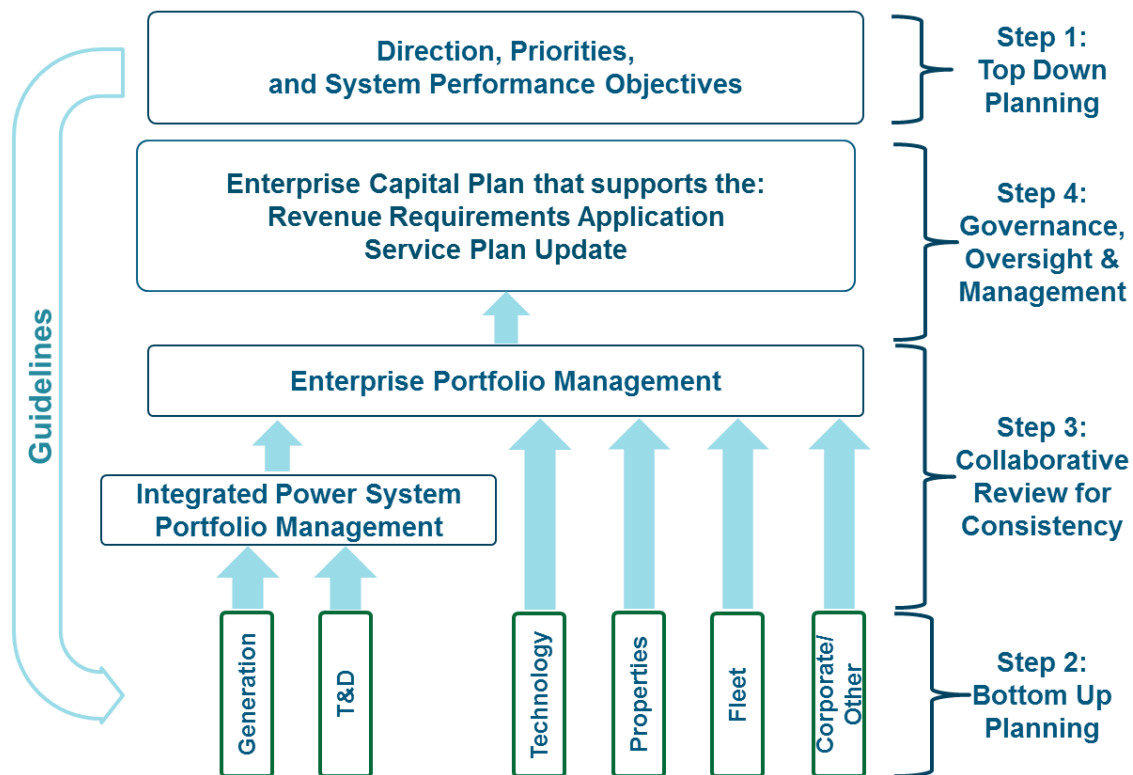
BC Hydro must be flexible and responsive to the investment needs of the system. The Enterprise Capital Planning Working Group manages the annual capital planning process so that the Capital Plan is updated and prioritized to respond to the latest information on the system risks and needs.

6.3.1.2 *The Capital Planning Process and Deliverables Are Clearly Articulated*

The enterprise wide capital planning process that is overseen by the Enterprise Capital Planning Working Group is clearly defined and the deliverables are well understood by the relevant areas of the business.

[Figure 6-4](#) below provides a simplified depiction of our capital planning process and identifies major outcomes and deliverables of the process. Each step of the process is described in the following sections.

Figure 6-4 Annual Enterprise Capital Planning Process

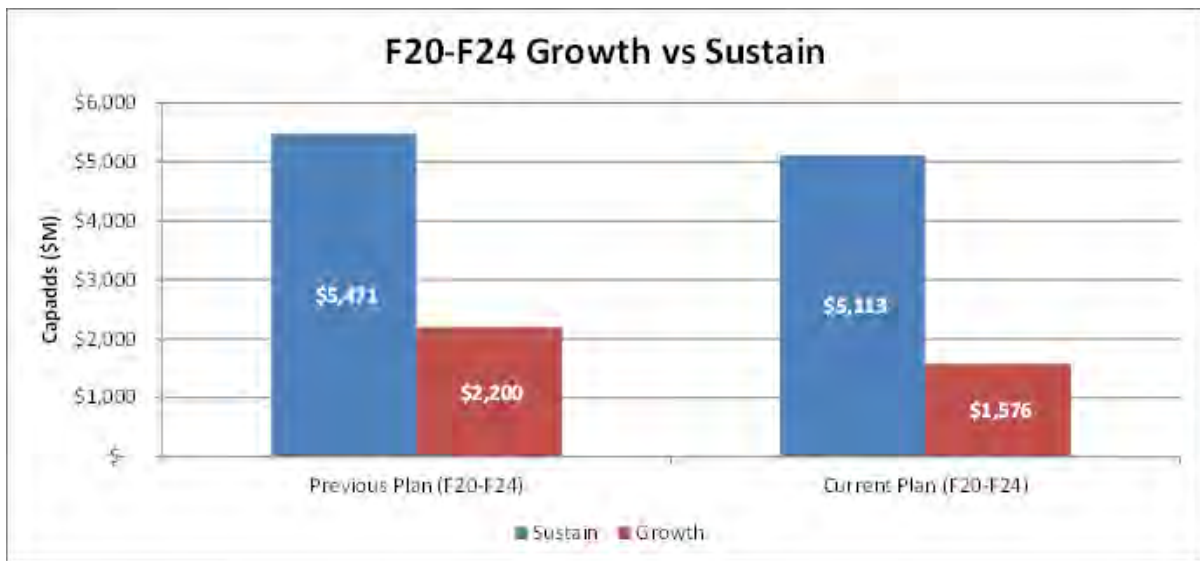


6.3.2 Step 1 - Load Forecast and System Performance Trends Inform Capital Investment Levels

A key element of the annual enterprise capital planning process is the direction provided by the Executive Team on long-term capital investment levels. In providing this direction the Executive Team considers BC Hydro's capital investment needs while balancing affordability, system performance and the need to continue to safely manage our assets. For the planning cycle that informed this application, the Executive Team direction on long-term capital investment levels considered recent trends in forecast load and system performance.

In the following sections, we describe how these trends informed the Capital Plan in this application. [Figure 6-5](#) below illustrates the outcome of this process for the overall level of planned capital additions in the fiscal 2020 to fiscal 2024 period.

Figure 6-5 Comparison of Fiscal 2020 to Fiscal 2024 Planned Capital Additions



6.3.2.1 The Recent Moderation of Forecast Load Growth Allows Moderation of Growth Capital Investment

As discussed in Chapter 3, the demand for electricity is growing at a more moderate rate than previously anticipated. This means that the timing of some planned investments to expand BC Hydro's system has changed and may not be required within the next ten years.

6.3.2.2 Investment in Sustainment Can Be Moderated Due to Strong System Performance

BC Hydro's fiscal 2019 to fiscal 2028 Capital Plan (Previous Capital Plan) had included an increasing level of sustaining expenditures over the ten-year period, primarily driven by the aging system assets and the expected rate of replacement required to maintain system performance.

In recent years, BC Hydro has made significant investments to maintain and, in some areas, improve the Power System. However, over time, the condition of some of the Power System assets has degraded. To this point in time, this degradation has not resulted in a corresponding decline in system performance or customer

reliability as measured by two industry-standard metrics. The consistently high level of performance has allowed us to moderate the planned investment in sustainment in the interest of mitigating impacts on customers.

System Average Interruption Duration Index (**SAIDI**) and the System Average Interruption Frequency Index (**SAIFI**) measure the duration and frequency of customer interruptions. BC Hydro tracks these metrics on an ongoing basis. Our performance on SAIDI and SAIFI metrics is also compared regularly with utility industry peers by the Canadian Electricity Association (**CEA**).

[Figure 6-6](#) below shows that in the past decade BC Hydro's unadjusted system average duration ("all-events" SAIDI) trend has performed as good as or better than the CEA composite,³⁰⁰ with the exception of fiscal 2016 due to the August 2015 summer wind storm.

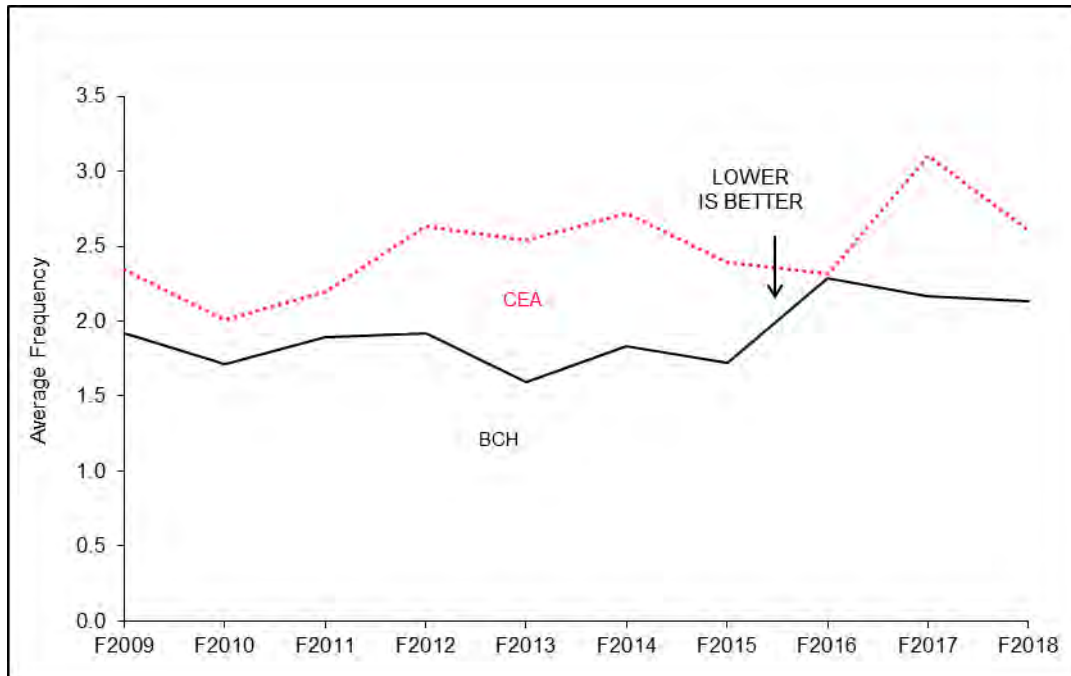
Figure 6-6 SAIDI (All Events, Not Normalized) – Average Interruption Duration per Average Customer



³⁰⁰ BC Hydro is included in the CEA composite.

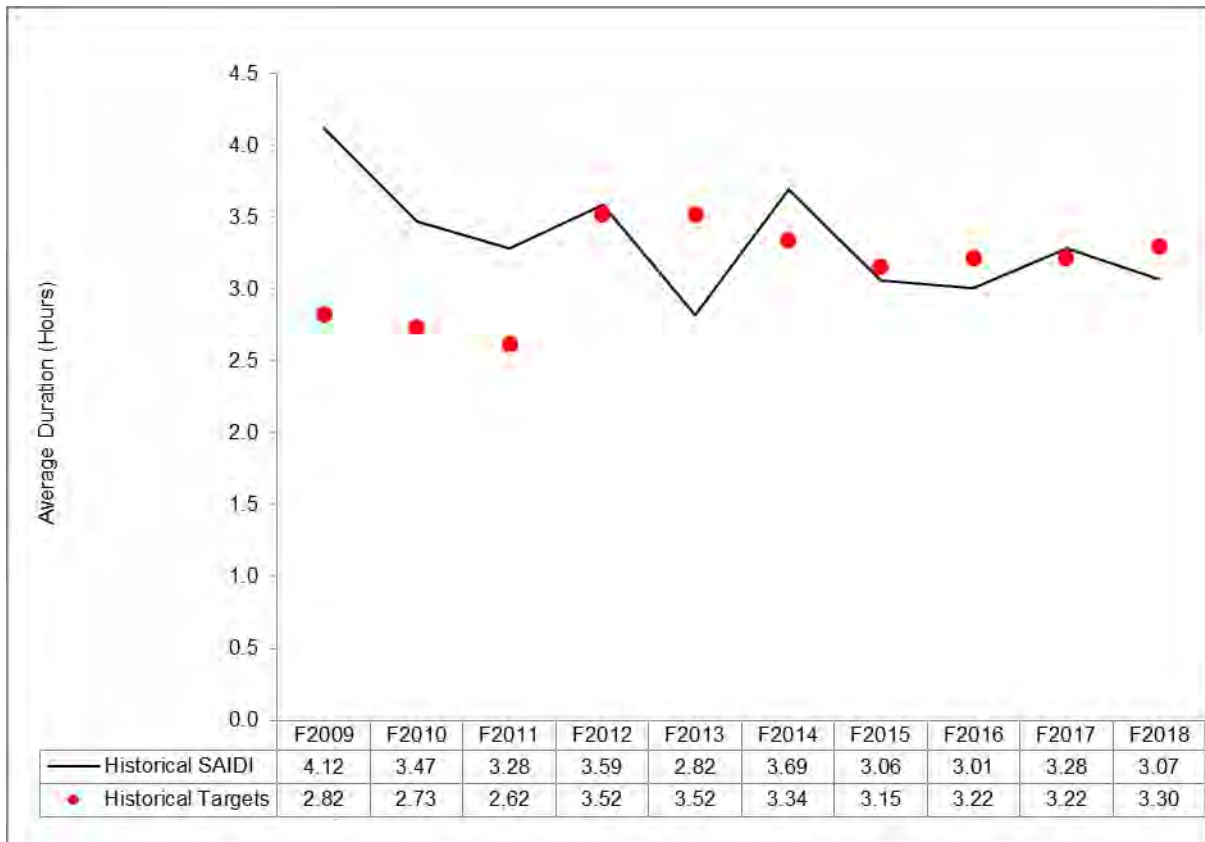
1 In addition, as shown in [Figure 6-7](#) below, BC Hydro's unadjusted system average
2 frequency ("all-events" SAIFI) trend has consistently out-performed the CEA SAIFI
3 composite.

4 **Figure 6-7 SAIFI (All Events, Not Normalized) –**
5 **Average Number of Interruptions per**
6 **Average Customer**



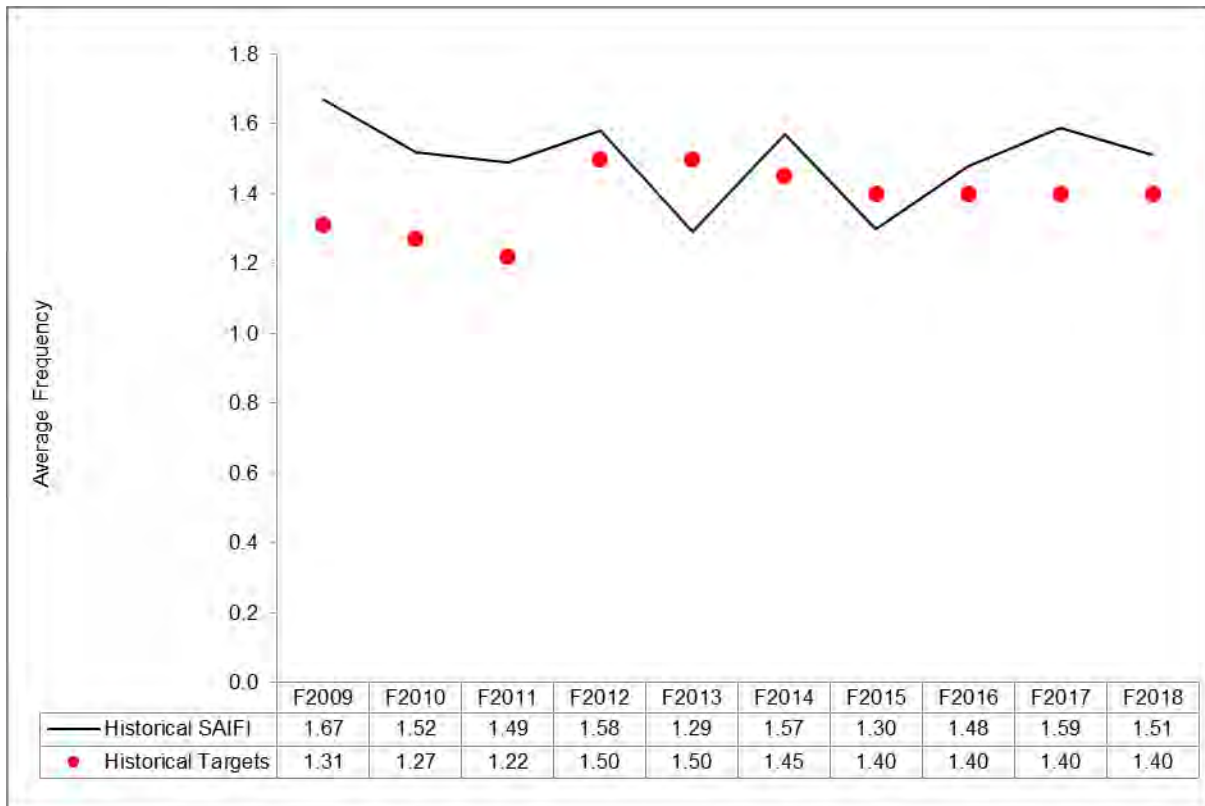
7 As shown in [Figure 6-8](#) below, when outage impact related to uncontrollable major
8 weather events are removed, normalized SAIDI, which measures the total outage
9 duration with storm impact adjustments, experienced by an average customer in a
10 year, was 3.28 hours in fiscal 2017, and further improved to 3.07 hours in
11 fiscal 2018.

Figure 6-8 SAIDI (Normalized)



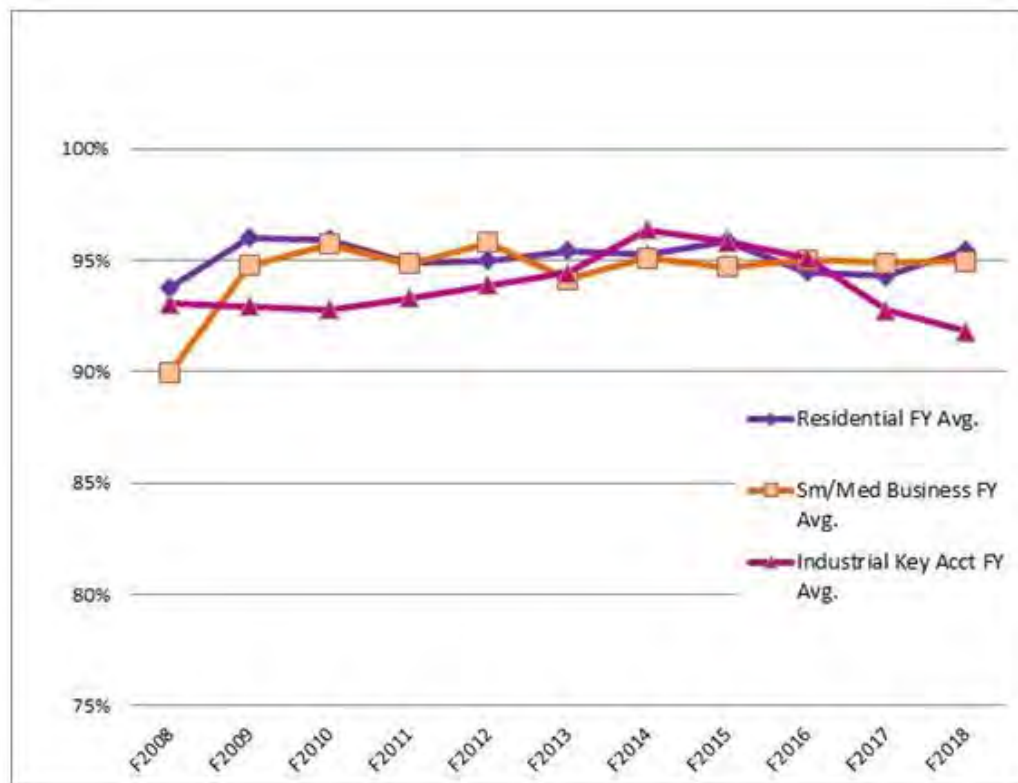
- 2 As shown in [Figure 6-9](#) below, normalized SAIFI, which measures the number of
 3 sustained disruptions per year excluding major events, was 1.59 disruptions in
 4 fiscal 2017, and 1.51 disruptions in fiscal 2018.

Figure 6-9 SAIIFI (Normalized)



In addition, the reliability scores in BC Hydro's Customer Satisfaction Index indicate that customers continue to be satisfied with the level of reliability they are receiving. This is shown in [Figure 6-10](#) below.

Figure 6-10 Customer Satisfaction Index on Reliability



Lastly, asset-related safety incidents on the transmission and distribution system have declined. This indicates that BC Hydro's investment plans are addressing safety-related risks on the system.

The consistently high level of historic system performance described above presented an opportunity to reconsider the appropriate level of sustaining expenditures. Specifically, for this Capital Plan, BC Hydro considered, at the portfolio level, how to moderate the level of planned sustaining investments, without materially impacting system performance.

As a result of this analysis, the overall portfolio level of sustainment expenditures over the ten-year period was reduced, relative to previously planned amounts.

These reductions are targeted as follows:

- 1 • **Reductions focused on the last five years:** The majority of the impact was in
2 the last five years of the Capital Plan period (fiscal 2025 to fiscal 2029).
3 Relative to the Previous Capital Plan, expenditures during the first five years of
4 the Capital Plan were relatively unchanged by these planning decisions.
5 Investments in the early years of the Capital Plan were mostly underway and
6 were considered appropriate to continue.
- 7 • **Dam safety spending is preserved:** Despite the overall reduction of capital
8 expenditures, Dam Safety investments have not been reduced in response to
9 these planning decisions. Dam Safety risk reduction targets remain consistent
10 with previous capital plans and with the approach approved by the BC Hydro
11 Board of Directors in 2014 to “manage the whole fleet of dams so that there is
12 no significant deterioration in the risk position and that the overall level of risk is
13 kept well within the limits considered to be tolerable.”

14 **6.3.2.3 *Reduced Investment Must Be Accompanied by Monitoring of Load*** 15 ***Forecasts, Asset Condition and Performance***

16 BC Hydro recognizes that the planned reduction in sustainment expenditures
17 relative to the previous plan must be accompanied by careful monitoring of asset
18 condition and performance. Our objective is to implement the reduction without
19 compromising long-term performance of key assets.

20 The impact on asset health is expected to vary across the system:

- 21 • As explained further in section [6.4.1.2](#), BC Hydro’s generation facilities are
22 categorized as “Key”, “Strategic” or “Available” according to the significance of
23 the facility to BC Hydro’s system. Under the Capital Plan, the condition of
24 BC Hydro’s “Key” and “Strategic” generation facilities is expected to improve.
25 For example, investments are planned for the G.M. Shrum, Mica, Bridge River
26 and Cheakamus facilities; and
- 27 • The recent trend of asset health degradation within some parts of the Power
28 System is expected to continue at this level of capital investment. For example,

over the next five years, the percentage of substation assets in Poor and Very Poor condition is expected to increase from 16 per cent to 19 per cent and the percentage of distribution assets in Poor and Very Poor condition is expected to increase slightly from 13 per cent to 14 per cent. The condition of the assets within BC Hydro's "Available" generation facilities, which provide less than 1 per cent of BC Hydro's annual energy, are expected to continue to deteriorate.

The linkage between asset health and reliability is complex. For example, most of BC Hydro's substations have built in redundancy so that the failure of a single asset will not result in a customer outage. In addition, the installation of automated devices, such as circuit re-closers, on BC Hydro's distribution system, has mitigated the risk of declining reliability from deteriorating asset health. BC Hydro continues to refine the appropriate balance between asset life, system performance and affordability and believes that this reduction in sustainment expenditures will provide more value to both current and future customers.

BC Hydro monitors system performance and forecast demand for electricity at both a system and regional level. Changes in system performance and load forecasts are likely to materialize over time, rather than suddenly. If system performance were to decline or if forecast demand were to change, BC Hydro has options to respond, including:

- Adjusting the level of asset condition driven replacements by redirecting funding from other parts of the BC Hydro capital investment portfolio;
- Updating operational or maintenance practices; and
- Bringing forward investments through our ex-plan governance process, which is described in section [6.3.5](#).

Overall, based on forecast load growth and system performance, BC Hydro believes that the balance reflected in the planned level of capital investment from fiscal 2020 to fiscal 2024 is appropriate.

6.3.3 Step 2 - Each Asset Category Uses Bottom-Up Planning Processes

Once the long-term capital investment levels have been established, preliminary financial targets are developed for each of the asset categories considering the factors discussed in the previous section as well as the historical composition of the capital plan. These preliminary financial targets are an input into the bottom-up planning process, as shown in [Figure 6-4](#) above.

Within the common Enterprise Capital Planning process, each asset category uses a bottom-up planning process that is tailored to the characteristics of the portfolio, considering:

- The function, criticality, volume and complexity of the different assets;
- The magnitude of the risks, issues and opportunities;
- The size, scope, complexity and costs of the capital investments; and
- The internal stakeholders that should be involved in the process.

The processes used for the asset categories are scaled as required. For example, the largest and most complex portfolios such as Generation or Transmission and Distribution, which collectively comprise the Power System, generally require more complex and detailed planning processes, and involve a broader discussion with internal stakeholders across BC Hydro.

Further information on the specific bottom up planning processes for the Power System, Technology, Properties and Fleet and Business Support/Other can be found in sections [6.5](#) to [6.8](#), respectively.

6.3.4 Step 3 - Enterprise Portfolio Management Process Validates and Prioritizes Capital Work Based on Risk and Drivers

Once bottom up planning has concluded, capital planning information is consolidated for:

- Collaborative peer reviews at the enterprise level;
- Validation of alignment with BC Hydro's strategic direction and priorities; and
- Identification of any potential areas for improvement in the process for the next annual capital planning cycle.

Peer reviews are conducted by the Enterprise Capital Planning Working Group, before the enterprise capital plan is submitted to BC Hydro's Executive Team and Board of Directors. The reviews focus on three main areas:

- An overall summary of each asset category portfolio;
- The quality of information used to develop the capital plan; and
- The risk profile of the consolidated capital plan.

The risk profile of the capital plan is based on BC Hydro's enterprise-wide framework for capital prioritization. This framework describes the assessment and prioritization process related to proposed capital investments. Investments are assessed based on the primary driver of the proposed investment, as follows:

- Investments that primarily mitigate risk are scored for prioritization using a methodology that is aligned with the BC Hydro Corporate Risk Matrix; and
- Investments that primarily create value are scored for prioritization using a net value per dollar invested metric. The value prioritization is mainly used for some capital expenditures in the Technology Portfolio.

Through BC Hydro's enterprise-wide framework for capital prioritization, capital investments are classified into one of three categories:

- Mandatory investments driven by legal and regulatory requirements;
- Committed investments not to be postponed. This category includes projects that were prioritized in previous capital plans and are now economically unreasonable to cancel; and
- Investments to be prioritized. This category includes projects that could be re-prioritized without significant costs.

The peer reviews conducted for the Capital Plan in this application resulted in the reallocation of some funding from the Power System portfolio to the Technology and Properties portfolios in the earlier years of the plan. This reallocation was cost neutral and offset by reallocations from Technology and Properties to Power Systems in the later years of the plan. This reallocation increased the amounts allocated to Technology and Properties assets in the earlier years of the plan to smooth the level of investment in these portfolios over the ten-year period and to avoid disrupting BC Hydro's ability to deliver planned investments. As a result, investments in these asset categories are more evenly distributed over the long-term.

6.3.5 Step 4 - Executive Team Reviews and Approves the Capital Plan

The final step in BC Hydro's annual enterprise capital planning process is the review and approval of the capital plan by the Executive Team and Board of Directors, which occurs as part of the annual budget and five-year forecast approval process. This review is conducted to assess whether the plan meets overall business objectives and provides a consistent and appropriate management of risks across all asset categories.

Once the capital plan is approved by the Executive Team, it is monitored, on an ongoing basis, by the Capital Delivery Management Committee. The committee focuses on the early years of the capital plan so that actual and forecast capital expenditures remain aligned with the original capital plan. This management is done

at a portfolio level so that, if required, adjustments can be made to re-direct the capital budget, as new information becomes available. To make these decisions, the committee considers financial impacts, the enterprise risk profile, and labour resource availability.

Decisions to reallocate the budget within the capital plan are governed through an ex-plan governance process, which considers the size of the ex-plan request. Requests less than \$3 million are reviewed at the Enterprise Capital Planning Working Group level, while requests greater than \$3 million are reviewed and approved at the Capital Delivery Management Committee level. Reallocations may result in the approval of new projects to address emerging issues, the advancement of future investments based on new information or the increase of funding to existing programs, in response to identified needs.

6.4 Power System Assets Capital Investments

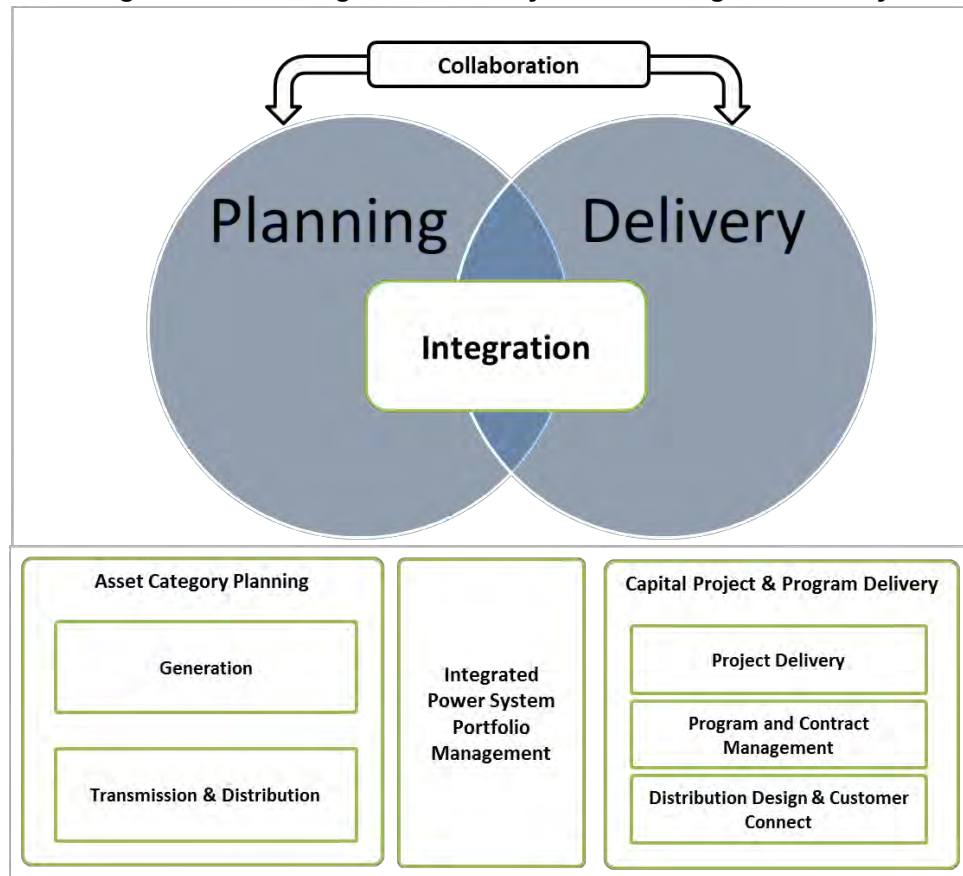
The Power System includes BC Hydro's Generation, Transmission and Distribution assets.

Over time, the condition and performance of existing assets degrade, regulatory and safety requirements change and new assets are required to address load growth and connect new customers. Together, these factors create issues, risks and opportunities to be addressed through capital investment.

The planning and delivery processes for the Power System are integrated, requiring a high degree of collaboration across the organization.

[Figure 6-11](#) below represents a high level depiction of the interaction between functional groups responsible for asset management and planning, and portfolio delivery when planning and delivering capital investments for the Power System.

Figure 6-11 Integrated Power System Planning and Delivery



Planning processes are in place to understand the issues, risks and opportunities associated with the assets and to identify the recommended capital investments.

- Sections [6.4.1](#) to [6.4.4](#) provide further information on the Power System assets, the bottom-up planning processes for each asset category and the integrated portfolio planning process for the Power System; and
- Sections [6.4.5](#) to [6.4.6](#) provide an overview of the collaboration and integration between planning and delivery through the annual capital planning process, the work planning process and the release of projects and programs to the KBUs responsible for delivery.

Delivery processes are in place to deliver projects and programs on time and on budget, and within scope. Investments associated with the Power System are

delivered by three different KBUs: Project Delivery, Program and Contract Management and Distribution Design and Customer Connect.

- Sections [6.4.6](#) to [6.4.9](#) explain how investments are assigned to each KBU as well as the project delivery practices used to deliver those investments;
- Section [6.4.10](#) describes the financial approval policies and procedures applicable to all capital investments; and
- Section [6.4.11](#) describes recent improvements to our project delivery practices.

Lastly, sections [6.4.12](#) to [6.4.15](#) present our forecast capital expenditures and additions for the Power System by asset category.

6.4.1 Generation Assets Capital Investments

During the test period, capital investments in generation assets include asset sustainment, dam safety and growth investments. Generation capital expenditures represent approximately 30 per cent of the BC Hydro Capital Plan during the fiscal 2020 to fiscal 2021 test period. The majority (75 per cent) of capital investments in the Generation portfolio during the test period are driven by the need to address issues and risks associated with existing facilities that are aging.³⁰¹

6.4.1.1 Generation Assets Are Aging and a Number Are at End-of-Life

BC Hydro's generation assets are aging, and a number of generation assets are now at end of life. BC Hydro's generation assets include 83 generating units at 30 hydroelectric generating facilities as well as 81 dams located at generating stations and at additional locations to provide water storage and water diversion functions. Generation assets also include three gas-fired units at BC Hydro's two thermal generating stations and four synchronous condenser units at a dedicated synchronous condenser station. BC Hydro also has 17 diesel generating

³⁰¹ Excluding the Site C Project.

stations and one hydroelectric generating station in areas not connected to the integrated electric system.

Construction of most of BC Hydro's large capacity generating facilities occurred in the 1960s, 1970s and 1980s, while the majority of BC Hydro's medium capacity facilities were constructed in the 1950s. The age of BC Hydro's generating facilities ranges from new to 94 years, with an average facility age of 52 years. Asset Health assessments indicate that a number of generation assets are now at end of life. An overview of generation asset health is provided in Appendix M.

BC Hydro manages its generation assets over their lifecycle by:

- Maintaining the assets so that they perform safely and reliably throughout their operating lives;
- Investing in the assets to extend their operating lives, enhance capability, manage risk, and increase efficiency and cost-effectiveness; and
- Managing public and worker safety risks associated with facilities, especially around reservoirs and dams.

Planning processes are in place to support these objectives and to align the portfolio of investments to effectively manage risk and customer needs within financial and labour resource constraints.

With the exception of the Site C Project, which is a growth project, the majority of capital investments in the Generation portfolio during the test period are driven by the need to address issues and risks associated with existing facilities. These investments are categorized as Generation Asset Sustainment and Dam Safety investments. The following sections describe BC Hydro's Generation Asset Sustainment and Dam Safety portfolios in more detail and then explain BC Hydro's bottom-up planning process for generation assets.

6.4.1.2 Generation Asset Sustainment Addresses the Highest Risks

The planned generation sustainment capital investments for the fiscal 2020 to fiscal 2021 test period will continue to mitigate or resolve the highest risks identified with BC Hydro's generation assets. Asset Sustainment represents 75 per cent of the Generation expenditures over the fiscal 2020 to fiscal 2021 test period.³⁰²

The risk assessment considers how important generation facilities are to the overall system, as well as the asset condition.

BC Hydro's generation facilities are categorized as "Key", "Strategic" or "Available", according to the significance of the facility to BC Hydro's system. An investment strategy is in place for each category which reflects the significance of the category of facility to the power system. [Table 6-6](#) below provides a list of BC Hydro's generation facilities by category.

³⁰² Excluding the Site C Project.

1
 2

Table 6-6 BC Hydro's Generating Facilities by Category

Facility Abb'n	Facilities	Facility Category	Year of Initial Operation	Current Age (Years) 2018	Current Maximum Capacity (MW)	Number of Units
BRR	Bridge River 1 & 2 (Originally developed 1934)	Key (Hydro)	1948	70	417	8
GMS	GM Shrum	Key (Hydro)	1968	50	2916	10
KCL	Kootenay Canal	Key (Hydro)	1975	43	582	4
MCA	Mica	Key (Hydro)	1976	42	2781	6
PCN	Peace Canyon	Key (Hydro)	1980	38	736	4
REV	Revelstoke	Key (Hydro)	1984	34	2368	5
SEV	Seven Mile	Key (Hydro)	1979	39	817	4
WAN	Waneta (Acquired 2018)	Note 1	1954	64	492	4
ALU	Alouette	Strategic (Hydro)	1928	90	9	1
ASH	Ash River	Strategic (Hydro)	1959	59	26	1
BSY	Burrard Synchronous Condenser note 2	Strategic (Synchronous Condenser)	1962	56	N/A	4
CMS	Cheakamus	Strategic (Hydro)	1957	61	160	2
COM	Clowhom	Strategic (Hydro)	1957	61	30	1
FNG	Fort Nelson	Strategic (Thermal)	1999	19	72	2
JHN	John Hart (Originally developed 1947)	Strategic (Hydro)	2018	0	135	3
JOR	Jordan River (Originally developed 1912)	Strategic (Hydro)	1971	47	167	1
LAJ	La Joie	Strategic (Hydro)	1957	61	22	1
LB1	Lake Buntzen (Originally developed 1903)	Strategic (Hydro)	1951	67	60	1
LDR	Ladore	Strategic (Hydro)	1956	62	52	2
PUN	Puntledge (Originally developed 1912)	Strategic (Hydro)	1955	63	26	1
RPG	Prince Rupert Gas	Strategic (Thermal)	1973	45	46	2
RSN	Ruskin (Originally developed 1930)	Strategic (Hydro)	2016	2	106	3
SCA	Strathcona	Strategic (Hydro)	1958	60	63	2
SFN	Stave Falls	Strategic (Hydro)	1999	19	90	2
SON	Seton	Strategic (Hydro)	1956	62	44	1
WAH	Wahleach	Strategic (Hydro)	1952	66	61	1
ABN	Aberfeldie (Originally developed 1922)	Available Energy (Hydro)	2008	10	25	3
ELK	Elko	Available Energy (Hydro)	1924	94	11	2
FLS	Falls River	Available Energy (Hydro)	1930	88	7	2
SHU	Shuswap	Available Energy (Hydro)	1929	89	6	2
SPN	Spillimacheen	Available Energy (Hydro)	1955	63	5	3
WGS	Whatshan (Originally developed 1951)	Available Energy (Hydro)	1972	46	60	1
WHN	Walter Hardman	Available Energy (Hydro)	1960	58	10	2
Note 1	On July 26, 2018, BC Hydro became the sole owner of Waneta. Teck Metals Ltd ("TML") continues to act as the Operator of the facility during the 20 year lease term, and is required to operate, manage, and maintain Waneta in accordance with the terms of the Co-Possessors and Operating Agreement ("COPOA").					
Note 2	Burrard Synchronous Condenser facility was previously the Burrard Thermal generating facility.					

- 1 • **“Key” generating facilities:** Seven “Key” generating facilities represent the
2 largest hydro-electric facilities on the BC Hydro system and produce
3 approximately 90 per cent of BC Hydro’s average annual energy;
- 4 • **“Strategic” facilities:** Eighteen “Strategic” facilities represent all generating
5 stations on Vancouver Island, all stations located on cascading systems, all
6 thermal generation stations and generating stations required to provide voltage
7 support to the transmission network. These facilities produce approximately
8 9 per cent of BC Hydro’s average annual energy and provide significant
9 additional value to BC Hydro due to their geographic location and system
10 support services;
- 11 • **“Available” facilities:** Seven “Available” facilities represent those facilities that
12 are of lower strategic importance and produce less than 1 per cent of
13 BC Hydro’s average annual energy; and
- 14 • **Waneta two-thirds:** On July 26, 2018, BC Hydro became the sole owner of
15 Waneta. Teck Metals Ltd. continues to act as the Operator of the facility during
16 the 20-year lease term. In that role, Teck is required to operate, manage, and
17 maintain Waneta in accordance with the terms of the Co-Possessors and
18 Operating Agreement (“COPOA”), which includes capital planning and
19 operating to a prudent owner standard, exercising the degree of care and skill
20 of an experienced dam operator and acting in accordance with Good Utility
21 Practice.

22 As Teck is the Operator of Waneta, processes that BC Hydro generally uses for
23 internal asset management and planning purposes will not be applied.

24 BC Hydro will retain an oversight role as part of the Waneta Operating
25 Committee, including reviewing the annual operating plans for Waneta.

26 The condition of assets across BC Hydro’s generation fleet is a foundational input to
27 the planning process. BC Hydro evaluates the condition of its major equipment
28 (turbines, generators, governors, exciters, transformers, and circuit breakers) based

on the latest available maintenance test and inspection data, following BC Hydro's Equipment Health Rating methodology. This provides a systematic, objective, repeatable, and transparent assessment of equipment health. Factors influencing the Equipment Health Rating include:

- Equipment health;
- Maintenance history;
- Equipment reliability;
- Availability of spare parts;
- Availability of technical support; and
- Known equipment type design problems.

Asset health or condition information is used to assess and manage risk and to prioritize the need to make investments to preserve and sustain the generating units. Each health assessment results in a rating of Good, Fair, Poor, or Unsatisfactory.

Over the test period, sustaining capital expenditures will be focused at the G.M Shrum, Bridge River 1 and 2, Mica, and Cheakamus generating stations.

6.4.1.3 *Dam Safety Is Another Focus of Generation Expenditures*

Dam Safety represents 25 per cent of the Generation expenditures over the test period,³⁰³ recognizing the potential for catastrophic consequences in the unlikely event of a failure.

BC Hydro's dams are subject to the British Columbia Dam Safety Regulation, which defines a "Dam" as:

- (a) A barrier constructed for the purpose of enabling the storage or diversion of water diverted from a stream or an aquifer, or both; and

³⁰³ Excluding the Site C Project.

(b) Other works that are incidental to or necessary for the barrier described in paragraph (a).

Consistent with the Dam Safety Regulation, BC Hydro's Dam Safety portfolio comprises all physical features, structures and mechanisms - both constructed and natural - that retain the reservoirs and control the passage of flows past the dam.

The Dam Safety Regulation classifies dams according to the consequences of their failure, such as the potential for loss of life, environmental damage and economic impacts. Classifications range from "Low Consequence" to "Extreme Consequence". These classifications dictate the required frequency of safety activities performed on the dam and are further used to guide the selection of the dam's design and performance criteria.

Dam Safety issues and risks involve:

- The safe storage and controlled passage of water under normal conditions;
- The ability to pass floods (from the annual freshet to extreme events); and
- The ability to withstand a major earthquake without any harmful release of water.

Dam Safety risks generally have a relatively low probability of occurrence but, if realized, a very high consequence. Key drivers of Dam Safety capital investments in the test period include:

- **Seismic Risk:** The seismic performance at a number of BC Hydro's major dams is below current Canadian guidelines. For example, the John Hart Dam is classified as an "Extreme Consequence" dam under the British Columbia Dam Safety Regulation. This means that, under the 2007 Canadian Dam Association Guidelines, the expected seismic performance of this dam is to have no uncontrolled release of the reservoir during and following earthquake ground motions that would be expected to occur on that site no more than once every

10,000 years. Seismic upgrades to the John Hart Dam and spillway are required and planned to achieve this level of seismic performance.

- **Reliability of Spillway Gates:** A spillway is an essential component of any dam facility. It provides a means for passing sufficient quantities of water from the reservoir to the downstream water course when power generation is unavailable or insufficient to maintain required downstream flows or prevent the reservoir from rising above its maximum safe elevation. Discharge through a spillway may also be required for emergency reservoir drawdown, such as in the event that a defect develops and/or is identified within the dam and there is a need to reduce the load on the dam. Discharge through a spillway is regulated by gates located at its upstream end. Some of BC Hydro's spillway gates have design or condition-based deficiencies that impinge upon their operational reliability and which, due to their critical safety function, pose a risk. To address this risk, the Capital Plan includes investments to improve the reliability of spillway gates at the W.A.C. Bennett Dam, Ladore Dam, Strathcona Dam, John Hart Dam and Mica Dam.
- **Condition of Civil Structures:** BC Hydro has a number of facilities where the integrity or degradation of the existing civil structures poses a risk to the ability to store or pass water safely. For example, reservoir booms throughout BC Hydro's system are aging and deteriorating. Poorly functioning booms can allow large debris in the reservoir to reach the dam, blocking spillways and other water passages and interfering with or preventing the proper function of these critical features of a dam. Projects to replace a number of reservoir booms will proceed within and beyond the test period.

6.4.2 Generation Bottom-Up Capital Planning Process

The following sections describe the steps of BC Hydro's bottom-up capital planning process for generation assets.

6.4.2.1 Step 1 - Generation Strategic Asset Management Plan

First, BC Hydro considers its Generation Strategic Asset Management Plan. This plan sets out ten year strategies for each facility category – Key, Strategic and Available - to support appropriate resource allocations and performance targets for the facilities.

- **Key facilities:** BC Hydro has implemented a component replacement strategy for its Key facilities. Under this strategy, all major equipment at Key facilities will be restored to Good or Fair condition or will have work underway to restore them to Good or Fair condition, within ten years. This strategy means that, in aggregate, the reliability of Key facilities will be maintained at or slightly above the average of similar facilities, as reported by the Canadian Electricity Association;
- **Strategic facilities:** Equipment in “Poor” or “Unsatisfactory” condition at Strategic facilities will either be refurbished or replaced within ten years, will have work underway to be refurbished or replaced within ten years or will have a long-term plan developed to mitigate the risk of equipment failure. This strategy means that, in aggregate, the reliability of Strategic facilities will be maintained at or restored to the average of similar facilities, as reported by the Canadian Electricity Association; and
- **Available facilities:** With the exception of Whatshan and Aberfeldie (the largest and newest Available facilities) all other Available facilities will receive minimal capital investment and will be taken out of service when they are no longer able to safely generate electricity. BC Hydro will perform regular maintenance and inspection on these assets to keep them safe and inform investment and operating decisions. Options to re-furbish, re-develop or

decommission Available energy facilities that have been taken out of service will be developed as required. Decisions on these options will be informed by BC Hydro's long-term load resource balance. Over time, this strategy may result in a gradual reduction of the energy produced by Available facilities.

6.4.2.2 Step 2 - Dam Safety Investment Strategy

Second, BC Hydro's level of investment in Dam Safety is targeted to address identified deficiencies in the dams and their appurtenant structures so that:

- There is no significant deterioration of BC Hydro's overall risk position with respect to these assets; and
- The overall level of risk is kept well within tolerable limits as guided by the Canadian Dam Association's Dam Safety Guidelines and the International Commisison on Large Dams' Bulletin on Dam Safety Management.

In addition, BC Hydro's dam safety investments also consider qualitative judgements made, on a case by case basis, with regulators and government representatives, First Nations and stakeholders.

This targeted level of investment accounts for the both the experienced and expected future wear and tear of the dams, identification of new issues, and improved understanding of previously identified issues through engineering investigations.

Identified deficiencies are rated by a "Vulnerability Index" that considers:

- The extent to which the design or performance of a particular dam feature (deficiency) differs from accepted good practice;
- The extent to which that feature contributes to the safe performance of the dam;
- The frequency at which the feature is potentially stressed to the limits of its performance; and

- The effectiveness of any interim risk controls that might be in place.

At each dam, issues and risks are grouped to form a project or set of projects based on asset type, similarity of issues or solutions, and location within the facility or system. These projects are then prioritized across the system by considering:

- The potential reduction of the Vulnerability Index;
- The consequence classification of the dam;
- The cost and time to effect remediation compared to the benefits from risk reduction;
- The sequencing of required enabling projects; and
- The completeness of BC Hydro's understanding of the issue and potential remediation.

BC Hydro's most recent internal audit of the Dam Safety Program, conducted by a team that included international subject matter experts in Dam Safety management and hazardous process industries, found that

"BC Hydro continues to be a leader in risk assessment in the international dam safety community with a transparent, systematic and robust risk assessment process."

6.4.2.3 Step 3 - Growth Driven Generation Investments

Third, BC Hydro identifies opportunities to enhance the capability or increase the efficiency of existing facilities. Generation growth investments are integrated into the capital plan when there is an identified need for increased energy or capacity resources.

6.4.2.4 Step 4 - Facility Asset Plans

Fourth, BC Hydro considers the Facility Asset Plans for its hydroelectric generating facilities, thermal generating and synchronous condenser stations. Facility Asset Plans formulate, document and recommend a ten year investment strategy for each

1 facility, with a focus on the near years of the plan. These strategies account for the
2 facility's role in BC Hydro's system, its Equipment Health Ratings, dam safety issues
3 and deficiencies, performance levels and targets, risks, and growth opportunities.
4 Capital upgrade projects to implement these strategies are carefully planned so that
5 unit outages and maintenance work are coordinated with power system
6 requirements.

7 As they are developed, each Facility Asset Plan is presented to the Asset and Risk
8 Planning Committee for agreement in principle and endorsement. This committee
9 provides input to the Facility Asset Plan on all issues, risks and planned
10 investments.

11 Facility Asset Plans are updated periodically to reflect the latest information,
12 including changes in priorities and strategies which influence the scope and timing of
13 facility plans and investments. A Facility Asset Plan may also be updated if new
14 information emerges that affects the investment strategy for the facility. Between
15 updates, BC Hydro continues to monitor the risks and issues associated with the
16 facilities and makes adjustments, if needed.

17 Summaries of Facility Asset Plans are provided in Appendix K.

18 **6.4.2.5 Step 5 – Annual Capital Planning Review**

19 Fifth, as part of the annual capital planning process, BC Hydro undertakes a review
20 of the planned investments for each facility. Investments are reviewed to check that
21 the facility asset planning process has been applied consistently, the data quality is
22 sufficient and the investments are appropriately prioritized and timed. These
23 investments are then submitted into the Integrated Power System Portfolio
24 Management process, as described in section [6.4.5](#) below.

6.4.3 Transmission and Distribution Assets Capital Investments

Transmission and Distribution capital expenditures represent approximately 60 per cent of BC Hydro's planned capital expenditures over fiscal 2020 to fiscal 2021.

Over the test period, approximately half of the forecast capital investment in the transmission and distribution systems are investments in sustainment to address issues and risks associated with the asset condition of existing facilities. The other half is related to growth.

6.4.3.1 Transmission and Distribution Assets Are Aging and Many Require Investment in the Near Term

BC Hydro's transmission and distribution assets are aging, and the asset health assessment of these assets indicate that a number of them are now at end of life.

BC Hydro's transmission and distribution assets include over 18,000 circuit km of transmission overhead lines, approximately 350 km of transmission subterranean and submarine cables, 323 substations, an integrated telecommunication system, approximately 58,000 circuit km of distribution overhead lines and 10,000 circuit km of distribution underground lines.

A large portion of the transmission system was built in the 1960s and 1970s and these assets are, or soon will be, reaching or exceeding end-of-life condition.

Similarly, a large portion of the distribution system has, or soon will be, exceeding its design life. Asset Health assessments indicate that approximately 10 per cent of the transmission and distribution assets are in poor to very poor condition, which requires either remediation work or replacement within the next ten years. It is expected that a certain portion of assets will be in Poor or Very Poor condition at any point in time. An overview of transmission, distribution and substation asset health is provided in Appendix N.

- 1 Overall, BC Hydro has approximately four million individual transmission and
2 distribution assets. [Table 6-7](#) below provides the average asset age, by asset class.

3 **Table 6-7 Average Asset Age by Asset Class**

	Asset Class	Number of Assets	Average Age
Distribution	Capacitors	405	22
	Cutouts	408,647	17
	O/H Conductors Primary (circuit km)	48,294	30
	O/H Switches	12,343	18
	O/H Transformers	283,161	25
	Others	39,268	
	Recloser	1,400	5
	Revenue Meter	2,035,097	5
	Street Light	91,977	23
	U/G Cables Primary (circuit km)	10,874	20
	U/G Transformers	67,364	22
	Voltage Regulators (Distribution)	575	7
	Wood Poles	891,328	27
	Total:	3,890,733	
Substation	Batteries	338	11
	Circuit Breakers	3,994	19
	Disconnect Switches	14,130	30
	Fire Protection Systems	156	28
	Gas Insulated Switchgear	508	16
	Instrument Transformers	8,455	21
	Mobile Transformers and Substations	9	31
	Others	3,225	
	Protection and Control Systems	12,496	24
	Reactors	1,949	28
	Series Capacitors	14	27
	Shunt Capacitors	434	18
	Standby Generators and Fuel Systems	75	23
	Static Var Compensators	5	18
	Station Insulators	435	42
	Surge Arrestors	6,277	14
	Synchronous Condensers	4	47
	Transformers/Tap Changers	1,437	35

	Asset Class	Number of Assets	Average Age
	Voltage Regulators (Substation)	362	38
	Total:	54,303	
Transmission	Conductor Systems (circuit km)	19,349	44
	Line Disconnect Switches	286	26
	Metal Support Structures	24,366	44
	Others	319	
	Underground Cables (circuit km)	346	38
	Wood Pole Structures	82,142	44
	Total:	126,808	

1 BC Hydro has established planning processes in place to:

- 2 • Develop transmission and distribution system plans for the safe and reliable
 3 delivery of electricity to customers;
- 4 • Connect new customers and generators;
- 5 • Expand networks with existing capacity constraints to meet anticipated load
 6 growth;
- 7 • Manage asset performance; and
- 8 • Meet regulatory requirements.

9 Over the test period, the transmission and distribution capital forecast includes
 10 investments in both sustainment and growth expenditures. As indicated above,
 11 approximately 50 per cent are sustainment expenditures, driven by the need to
 12 address the issues and risks associated with existing assets. Sustainment
 13 expenditures are made so that the assets perform as required throughout their
 14 lifecycle. Investments in existing assets include activities such as:

- 15 • Replacement of assets based on condition;
- 16 • Enhancements to maintain or improve customer reliability and extend asset life;
- 17 • Upgrades to mitigate risks including safety, environment, security and seismic;

- Improvements to meet evolving regulatory standards; and
- Relocations to address third-party requests.

6.4.3.2 BC Hydro Is Investing a Similar Amount as in Past Years to Replace Existing Assets

The replacement of assets represents 75 per cent of transmission and distribution sustainment expenditures, or approximately \$640 million over the test period. This level of expenditures is similar to the expenditures in the previous three years. While this level of investment will result in a gradual deterioration in overall asset condition of the transmission and distribution assets, the associated risk is mitigated.

Assets are replaced when the equipment performance can no longer be managed due to comparatively high cost or due to lack of parts and inadequate manufacturer support. Asset replacements are also required to mitigate increasing public and worker safety risks as well as environmental risks, which could result from asset failures.

The Asset Health Index is used to assess the condition of the transmission and distribution assets. This approach considers factors such as asset age and available test and inspection data and then assigns ratings of Very Good, Good, Fair, Poor, or Very Poor to each asset. These ratings can be grouped and analyzed to assist with investment decisions.

Most replacements are the result of proactive inspections and maintenance. For example, cedar wood poles are tested and treated 20 to 29 years after initial installation and then every ten years thereafter. Units that fail the test criteria are then scheduled for replacement.

In cases where the impacts of asset failure on customer reliability are low and proactive maintenance is ineffective in extending asset life, a 'run to failure' strategy is used to minimize the life cycle costs of managing the assets. Examples of asset classes that are 'run to failure' include overhead distribution transformers.

At the level of capital investment in this Capital Plan, the number of assets in Poor or Very Poor condition is expected to gradually increase, which will increase the probability of failure associated with some components of the transmission and distribution system. The potential impact of asset failures on system performance is mitigated by the redundancy on the system as well as the installation of automated devices.

6.4.3.3 *Customer Reliability Investments Are Aimed at Managing Current Reliability Levels*

Customer reliability investments include upgrades to existing assets as well as adding new assets to manage reliability. Customer reliability capital expenditures are required during the test period to manage current levels of system performance and total approximately \$100 million. Examples of customer reliability projects include backup circuit ties to enable faster restoration in the event of customer outages as well as circuit re-locations and re-configurations to avoid potential outage causes, such as tree and vegetation contacts.

6.4.3.4 *A Portion of the Sustainment Budget is Directed at Mitigating Other Risks*

A portion of the transmission and distribution capital investment portfolio is to address a variety of other risks including public and worker safety, environment, fire, security, seismic and extreme weather.

Capital expenditures to address other risks associated with transmission and distribution are expected to total approximately \$45 million in the test period. This includes:

- **Safety risk mitigation:** Examples of safety projects include the replacement of H-Frame structures in the alleys of downtown Vancouver, which pose a public safety risk due to reduced clearances to buildings as well as a project to replace concrete poles, which pose an employee safety risk due to a lack of adequate integral bonding.

- 1 • **Environmental risk mitigation:** Examples of environmental projects include
2 those to manage oil-filled equipment to avoid the risk of spills as well as
3 projects to modify structures in areas where protected bird species congregate
4 in order to avoid electrical contact incidents.
- 5 • **Fire and security risk mitigation:** Examples of projects to address fire and
6 security risk at substations include the installation or upgrading of fire protection
7 systems or the installation of access detection and control, video monitoring,
8 perimeter fencing and gate upgrades.
- 9 • **Extreme weather risk mitigation:** Examples of projects to address risks
10 related to extreme weather include installing piles, reinforcing foundations and
11 constructing protective structures such as retaining walls, riprap berms and
12 debris deflectors around transmission structures and their foundations, to
13 withstand storms, floods, landslides, and avalanches.

14 **6.4.3.5 Localized Growth Investments Are Driven by Emerging Demand**

15 Growth expenditures are required to expand the transmission and distribution
16 system to accommodate load growth and to connect new customers. This includes:

- 17 • Upgrades and additions of station equipment;
- 18 • Upgrades and additions of transmission lines and distribution feeders; and
- 19 • New service connections and upgrades.

20 Growth expenditures represent approximately 50 per cent of all transmission and
21 distribution expenditures during the test period.

22 Demand for electricity continues to increase in some areas of the province and
23 certain parts of the BC Hydro system are reaching capacity. In certain sectors of the
24 economy, such as the oil and gas sector in the Peace and North Coast regions,
25 economic growth is driving the need to reinforce the system in areas that do not

1 have the infrastructure to meet the emerging demand. In addition, new investments
2 continue to be required to connect new customers to the BC Hydro system.

3 Growth investments and their timing are informed by forecast load growth, resource
4 supply additions and existing system capacity.

5 Capital investments to interconnect transmission customers are also difficult to
6 forecast. Due to uncertain timing, location and scope, only known transmission
7 interconnection projects are included as specifically identified projects in the forecast
8 capital expenditures for the test period.

9 BC Hydro also includes provisions for emerging transmission interconnection
10 projects. These amounts are aligned with the historical levels of spend and
11 anticipated future activity. Deviations from these provisions, to respond to emerging
12 interconnection needs, require an adjustment of the timing or scope of other projects
13 and programs within the capital plan.

14 Due to the continued economic activity expected in the Liquefied Natural Gas and
15 Oil and Gas sectors, there are potentially significant upgrades to the transmission
16 system in the North Coast and Peace region that may be required in the near future.
17 These potential upgrades, including a project to convert the voltage of the electric
18 supply in the Dawson Creek area from 138 kV to 230 kV, are not currently included
19 in BC Hydro's Capital Plan. These projects would allow BC Hydro to serve potential
20 new LNG and oil and gas customers with clean renewable energy from the power
21 grid. BC Hydro will work with the load customers to define the need and scope of
22 these future projects. These projects will proceed once there is a formal commitment
23 from the potential customers. Depending on the timing, these projects will be either
24 incorporated in future annual capital plan updates or initiated under BC Hydro's
25 ex-plan governance process, described in section [6.3.5](#).

26 Distribution interconnection expenditures are more stable and are forecast based on
27 historical levels.

6.4.4 Transmission and Distribution Bottom-Up Capital Planning Process

The following sections describe the steps of BC Hydro's bottom-up capital planning process for transmission and distribution assets.

6.4.4.1 Step 1 – Identify the System and Asset Needs

First, BC Hydro identifies system and asset needs to be considered for remediation. This assessment includes reviews of system performance data to identify assets with degrading conditions, representing safety or environmental risks, not performing adequately or not meeting regulatory requirements. System and substation load forecasts are also developed to identify areas in the system that may require reinforcement. Based on these reviews, BC Hydro develops a preliminary approach and timeline for remediation.

The following information and data is used to assess system and asset needs:

- **Asset Health and Performance:** BC Hydro evaluates the condition of the Transmission and Distribution assets, based on the latest available maintenance test and inspection data, as well as engineering assessments and assigns an Asset Health Index to each asset. The methodology provides assessments that are objective, repeatable, and consistent across asset classes. Assets with an index of Very Poor are generally considered for reinvestment within three years and assets with an index of Poor are generally considered for reinvestment within ten years. The Asset Health Index methodology and summary ratings for transmission and distribution assets is provided in Appendix N;
- **Customer reliability:** BC Hydro also reviews reliability statistics, identifies assets with poor performance and develops solutions for improvement. For example, the worst performing distribution feeders are studied to determine the areas of under-performance, conduct root cause analysis and assess solutions for future investment to improve reliability;

- 1 • **Regulatory Requirements:** BC Hydro also evaluates the compliance of assets
2 with the regulatory requirements of the *Workers Compensation Act*, the B.C.
3 *Wildfire Act* and environmental laws as well as the requirements of Mandatory
4 Reliability Standards, Measurement Canada, and Transport Canada;
5 Compliance is addressed within the requirements of each regulation;
- 6 • **Load and Energy Forecasts:** BC Hydro assesses the capability of the
7 transmission and distribution system to meet expected peak demand and
8 accommodate forecast load and generation additions; and
- 9 • **Other Risks:** BC Hydro assesses the potential severity and likelihood for a
10 range of risks including safety, seismic, environment, fire, extreme weather,
11 and security. High risks, as determined by BC Hydro's enterprise-wide
12 framework for capital prioritization, are considered for remediation. The
13 enterprise-wide framework is discussed further in section [6.3.4](#).

14 **6.4.4.2 Step 2 – Determine the Scope of the Studies**

15 Second, BC Hydro determines the scope of studies to assess identified needs.
16 These studies integrate multiple needs, impacting the same parts of the system,
17 within a similar timeframe, so that they proceed through the planning process
18 together.

19 In this step, identified needs are reviewed by regionally-focused cross-functional
20 teams to determine integration opportunities. These teams consider how needs
21 relate to each other as well as the required timelines for remediation and the risks of
22 delay. These reviews may result in certain needs being addressed through
23 province-wide work programs or deferred due to low risk.

24 Third-party interconnection requests are not typically considered for integration with
25 other needs. These projects normally proceed individually through their respective
26 mandated and schedule-driven processes.

6.4.4.3 Step 3 – Undertake Studies

Third, BC Hydro studies identified needs in detail and identifies technically feasible alternatives to remediate these needs through projects or work programs. There are three types of studies: Area Plans, Substation Asset Plans and Asset Class Strategies. The studies vary from a few weeks to several years depending on the complexity of the needs and alternatives.

- **Area Plans:** Area Plans are specialized technical planning studies to identify alternatives to address needs related to issues such as load growth, new generation and system reliability. The Downtown Vancouver Electric Supply Plan and the Squamish Area Reinforcement Study are examples of integrated Area Plans;
- **Substation Asset Plans:** Substation Asset Plans are developed for substations with multiple pieces of equipment that require replacement within a similar timeframe. The Barnard Substation Asset Plan is an example of a substation asset plan; and
- **Asset Class Strategies:** Asset Class Strategies determine the appropriate remediation approach for each asset class. Asset Class strategies include replacing the asset or continuing to perform maintenance on the existing asset.

Summaries of Area Plans, Substation Asset Plans and Asset Class Strategies are provided in Appendix K.

6.4.4.4 Step 4 – Annual Capital Planning Review

Fourth, as part of the annual capital planning process, BC Hydro undertakes a review of planned investments. Investments are reviewed by cross-functional teams to align investments across the portfolios. In addition, investments are reviewed to check that the data quality is sufficient and the investments are appropriately prioritized and timed. These investments are then submitted into the Integrated Power System Portfolio Management process, as described in section [6.4.5](#) below.

6.4.5 Integrated Power System Portfolio Management Brings Planned and Ongoing Projects and Programs into One Portfolio

Once a year, forecasts for the planned generation, transmission and distribution projects and programs, developed through the bottom-up processes described in the preceding sections, are brought together with projects and programs already being delivered. This consolidation of a single Power System capital investment portfolio begins the final stage of the preparation of the Power System Capital Plan.

The enterprise-wide framework for capital prioritization, described in section [6.3.4](#), is used to categorize each investment in the initial portfolio, and assign risk to the deferral of the investments. Where labour resources have been identified as a risk to the delivery of the portfolio, the demands on the labour pool to deliver each investment are assessed and the availability of those resources are estimated.

In the most recent capital planning process, the prioritization of the portfolio for fiscal 2020 to fiscal 2024 was managed within the established level of capital investment, as discussed in section [6.3.2](#). This review considered the resource availability of various labour groups, including Communications, Protection and Control Technologists as well as Distribution Designers. While in previous planning cycles, the availability of Communications, Protection and Control Technologists has constrained BC Hydro's ability to include certain investments in its portfolio, recent measures have prevented the undue delay of higher risk investments. For example, BC Hydro has increased the availability of these labour resources through improved contract management which has diversified the external suppliers used to perform this work. As a result, in this most recent capital planning cycle, labour resource constraints did not trigger the deferral of investments in the fiscal 2020 to fiscal 2024 period at the portfolio level.

The final step of the process is to review the Power System capital investment portfolio to determine the highest priority projects and programs within the labour and financial constraints that have been identified. These results are then reviewed

with the leadership team of the Integrated Planning Business Group. This provides an opportunity for senior leaders to offer input and to align the portfolio business objectives. Once endorsed by the Integrated Planning leadership team, the Power System Capital Plan is submitted into the Enterprise Capital Planning process, which is described in section [6.3.4](#).

6.4.6 Planning and Delivery Processes Are Well Integrated

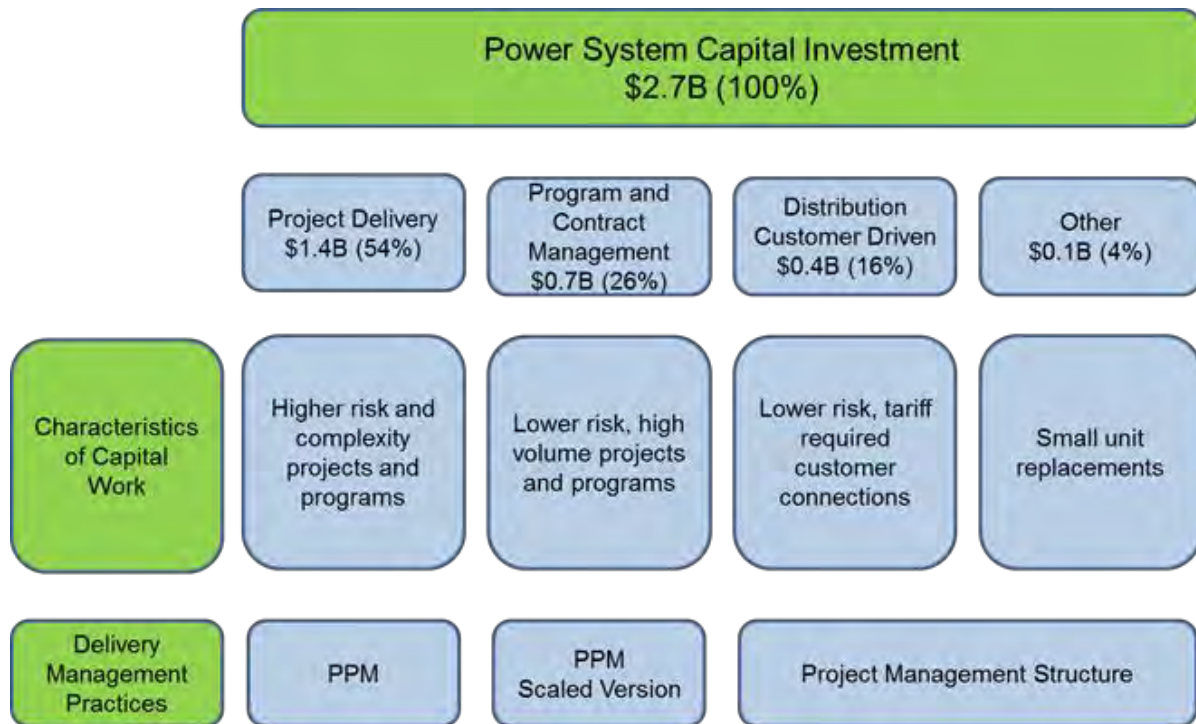
This section provides an overview of the collaboration and integration between planning and delivery through the annual capital planning process, work planning and the release of projects and programs to the KBUs responsible for delivery.

Investments associated with the Power System are delivered by three different KBUs: Project Delivery, Program and Contract Management and Distribution Design and Customer Connect. The processes followed by each KBU are adapted to suit the types of investment that they are responsible for delivering.

Large and complex investments generally require more rigorous delivery processes, involve a larger and broader group of internal and external stakeholders, and call for a high level of oversight and governance. Smaller projects or higher volume replacements of less complex assets require a scaled approach. Therefore, BC Hydro utilizes a range of delivery management practices to suit the range of investments that need to be delivered.

[Figure 6-12](#) below provides a summary of the Power Systems capital investments to be delivered by each KBU for fiscal 2020 to fiscal 2021 as well as the delivery management practice used to deliver those investments.

Figure 6-12 Summary of Power Systems Capital Investments by Delivery KBU for Fiscal 2020 to Fiscal 2021



6.4.6.1 Established Process Allows Early Identification of Issues and Resources

BC Hydro has an established process for early identification of issues and resources, so that work is assigned to the correct KBU with the appropriate delivery process for the nature of the investment and with resources to complete the work.

During the annual capital planning process to develop the capital plan for the Power System, the planning and delivery KBUs collaborate to:

- Consider labour resource availability, and validate that the Power System capital plan can be delivered with available internal and external resources;
- Determine the delivery model and assign capital investments to the appropriate KBU for delivery, considering factors such as:
 - ▶ Asset types and characteristics;

- ▶ The size, scope, complexity, duration and costs of the projects or programs;
and
- ▶ The number of internal and external stakeholders that need to be involved.
- Review the larger and more complex projects that are proposed to be delivered by the Project Delivery KBU. This includes a review of the problem statement, possible alternatives, project scope, project duration, delivery risks and potential operational constraints.

6.4.6.2 *Integrated Planning Remains Involved Throughout the Delivery Process*

After the completion of the annual capital planning process, BC Hydro begins work planning. This involves reviews of specific investments targeted for release in the next fiscal year. The planning and delivery KBUs review the scope of planned capital investments in greater detail and consider the portfolio of planned work as well as investments already underway, to determine the appropriate time to start new work.

After work planning is complete, capital investments are prepared for release to the appropriate KBUs for delivery. This step includes final planning reviews and required financial approvals to initiate the work.

Capital investments to be delivered by the Project Delivery KBU are released on a quarterly basis to respond to changing project and resource load conditions that may require the timing of work to be adjusted. This quarterly release plan is reviewed regularly to confirm that adequate resources are available prior to project release.

Capital investments to be delivered by the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU are typically released on an annual basis, prior to the start of the fiscal year. After planned capital investments have been released to the appropriate delivery group, the Integrated Planning Business Group continues to be involved throughout the delivery process and participates in key decisions and accountability meetings as the initiating group representatives.

6.4.7 Project Delivery KBU Uses the Program and Portfolio Management System to Deliver Larger, More Complex Projects

The Project Delivery KBU is responsible for delivering larger, more complex Power System projects. Approximately 54 per cent of the planned capital investments in the Power System for fiscal 2020 to fiscal 2021 will be delivered by the Project Delivery KBU.

A rigorous project delivery process is critical to delivering large or complex projects effectively. The Project Delivery KBU uses the Project and Portfolio Management System (PPM) system for consistent management of project risk, scope, schedule and cost.

6.4.7.1 Program and Portfolio Management System is Consistent with Industry Standards

PPM is BC Hydro's framework to manage engineering and construction projects that require engineering and/or project management services. It provides a consistent approach to minimize delivery risks. PPM practices are consistent with industry standards such as the Project Management Institute's Project Management Book of Knowledge and the Association for the Advancement of Cost Engineering International Recommended Practices. PPM is structured as a Quality Management System, consistent with the principles of ISO 9001, 2008 Quality Management Systems - Requirements.

There are three key components to the PPM system: practices, tools and learning. These components are described further in the sub-sections below.

6.4.7.2 PPM Practices Standardize the Management of Large, Complex Projects

All capital projects managed within PPM are delivered using a standard set of defined practices. BC Hydro's six defined Project Delivery Practices are:

- **Project Management** - The objective of this practice is to increase efficiency and discipline in our work by providing a consistent framework for delivering

1 projects and producing associated documentation. Application of these
2 practices increases safety for the public and employees, the quality of work
3 delivered through the projects and our future capacity by sharing knowledge
4 and lessons learned;

- 5 • **Design** – This practice aims to increase efficiency and consistency in
6 engineering design to provide facilities and equipment that are fit for purpose
7 and will operate safely, reliably, economically and in an environmentally
8 responsible manner, over the asset lifetime;
- 9 • **Construction and Contract Management** - This practice documents the
10 services that we apply to construction projects, programs, and portfolios to
11 achieve project objectives with regards to safety, security, environment, project
12 scope, quality, schedule, and cost;
- 13 • **Indigenous Relations** – This practice manages consultation and engagement
14 with First Nations on BC Hydro's capital projects;
- 15 • **Procurement** - The objective of this practice is to increase efficiency,
16 consistency and quality in major capital project procurement by providing a
17 framework for producing and delivering contracts that meets project
18 requirements; and
- 19 • **Regulatory, Environment, Social Issues and Properties** - The purpose of
20 this practice is to support the delivery of the regulatory, environment, social
21 issues and properties related services to capital projects by developing and
22 maintaining processes, tools, templates and guides to successfully achieve
23 project scope, schedule, quality and cost objectives. This supports regulatory
24 compliance as well as conformance with BC Hydro's policies, strategic
25 objectives and Statements of Strategic Intent.

26 In addition to the six Project Delivery Practices, PPM also includes Program
27 Management and Portfolio Management Practices.

The specific objectives of the Program Management Practice are to:

- Integrate program management with other Project Delivery practices including portfolio management and project management;
- Provide a common approach to the management of programs within BC Hydro;
- Support the planning and delivery of programs, including objectives, outcomes and benefits; and
- Support program managers with processes, techniques and templates.

The Portfolio Management Practice aims to establish consistent standards to support effective management of portfolios of project, program, and work program expenditures across BC Hydro. In particular, portfolio management guides the creation of a Portfolio Delivery Plan that describes the optimal approach to delivery of the entire portfolio, considering aggregation and coordination of opportunities and risk responses.

The Portfolio Management Practice also supports development of a baseline for measuring actual performance of the Portfolio Delivery Plan against the identified targets. This performance measurement allows management to understand and make more informed decisions on the interactions between projects, programs and work programs, to identify potential problems or opportunities, and to make timely interventions.

Underlying all of the Project, Program and Portfolio Practices are four “global” Practices:

- Document and Records Management is responsible for defining the framework in which documentation and records are required and dealt with for portfolio, program and project delivery;
- Performance Management defines key performance indicators that are implemented to measure the project;

- Reporting provides background on reporting, its structure, the basics about the reporting process as well as what is required to develop quality reports; and
- Resource Management ensures that the correct resources are assigned to complete projects on schedule.

6.4.7.3 *PPM Incorporates the Consistent Use of Technology in Project Management*

BC Hydro's PPM process uses technology solutions to manage project components. The following provides a high-level summary of these solutions and their application.

- There are two modules in the SAP system:
 - ▶ The Project Systems module provides a single system of record for work breakdown structures and financial data; and
 - ▶ The Business Warehouse module provides automated reporting on projects in the PPM process.
- The Primavera system has three components:
 - ▶ P6 software provides cost and schedule forecasts for each project;
 - ▶ Unifier is a contract management tool that is linked to the project schedules in Primavera P6; and
 - ▶ Primavera Risk Analysis performs schedule risk analysis on complex projects with a higher degree of risk.
- The PPM Workspace system (Microsoft SharePoint) provides document management functions.
- The PPM Information Centre is a web-based system that provides a record of the PPM practices.

6.4.7.4 PPM Includes a Learning Component to Support Best Practices

The Learning component of PPM involves the development of BC Hydro's staff and the sharing of knowledge and experience. This is achieved through:

- **PPM Information Centre** – A website of learning and reference materials associated with Project and Portfolio Management;
- **Community of Practice** – Team sessions for all BC Hydro staff and contractors facilitated by internal and external subject matter experts;
- **Communication Hub** – an online newsletter that provides role-specific, directed communications of changes that affect how we deliver PPM projects;
- **Learning Plans** - including role-based learning available online for Document Coordinators, Schedulers and Work Package Managers to provide easy access to role specific training information;
- **Career Development site** – career pathways and progression models based on Project Delivery roles;
- **Training Sessions** – BC Hydro hosts bi-weekly Community of Practice Learning events as well the International Project Management day, where internal and external presenters share their knowledge of best practices, lessons learned and provide an opportunity to network with others; and
- **Industry Organizations** – BC Hydro participates in industry groups to share Project Management best practices, including the Project Management Institute West Coast Chapter, Western Energy Institute, Canadian Electric Utility Project Management Network and Utility Peer Group (consisting of North American utilities).

6.4.7.5 Project Delivery Lifecycle Involves Staged Refinement of Scope and Estimates and Gate Approvals

The delivery lifecycle of PPM projects is divided into four phases: Initiation, Identification, Definition and Implementation. Each phase is further divided into various stages. The lifecycle represents a staged approach to project definition and gate approvals.

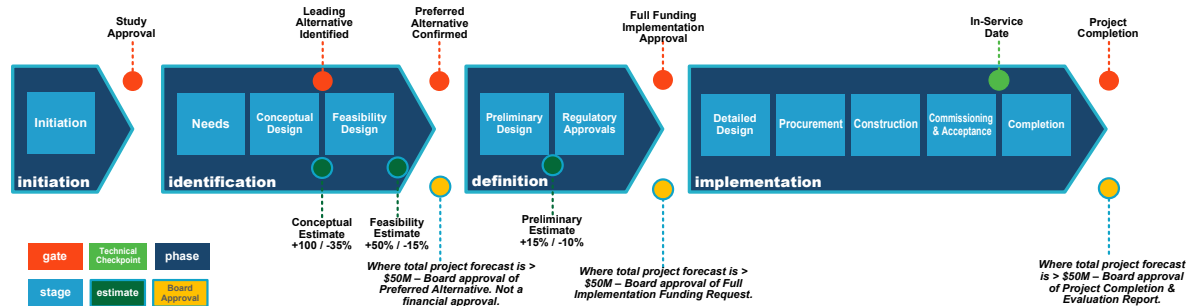
As projects move through this process, they become more defined. The increased level of definition allows for updated cost estimates to be developed. Cost estimates are provided at completion of the following stages:

- Conceptual Design: This estimate has an expected accuracy range of +100 per cent and -35 per cent;
- Feasibility Design: This estimate has an expected accuracy range of +50 per cent and -15 per cent; and
- Preliminary Design: This estimate has an expected accuracy range of +15 per cent and -10 per cent.

Gate approvals also occur at various points of the project lifecycle. Each gate is a formal approval point where key information on project cost, schedule, scope, procurement and risk is presented to the Gate Board. Further information on Gate approvals is provided in section [6.4.7.10](#) below.

[Figure 6-13](#) below provides a summary of the project delivery lifecycle. The Gates following each phase of the project lifecycle are shown as red circles, and approvals by the Board of Directors are shown in yellow circles. These project lifecycle phases and stages are non-discretionary.

Figure 6-13 PPM Project Lifecycle



The following sections describe the four phases of the PPM Project Lifecycle: Initiation, Identification, Definition and Implementation.

6.4.7.6 Phase 1 in PPM Project Lifecycle: Initiation

The Initiation Phase begins by establishing an issue, risk or opportunity to be addressed through a planned capital project. A Study Approval Gate occurs at the end of the Initiation phase to conclude this phase and provide approval to proceed to the Needs and Conceptual Design Stages of the Identification Phase. This Gate represents the release of the project from Integrated Planning to Project Delivery. A Project Manager is then assigned to manage the specific project through to completion.

6.4.7.7 Phase 2 in PPM Project Lifecycle: Identification (+100/-35 per cent)

The Identification Phase consists of three stages: Needs, Conceptual Design and Feasibility Design.

- **The Needs Stage** clarifies and validates the risk, issue or opportunity to be addressed and develops a selection of high-level solution alternatives for further consideration. In this stage, an initial Work Breakdown structure, Statement of Objectives and Project Plan are developed. This includes the development of documents and systems to support the project delivery process throughout the lifecycle of the project;

-
- 1 • **The Conceptual Design Stage** analyzes the alternatives developed in the
2 Needs stage and selects the alternatives to be carried forward into the
3 Feasibility Design stage. For each selected alternative, an overall concept plan
4 is developed including preliminary drawings of major project features, a general
5 definition of equipment and system requirements and an overview of First
6 Nations, stakeholder, environmental, socio-economic and procurement
7 considerations. The selected alternatives are refined to eliminate the
8 alternatives that do not meet the project objectives and to recommend a
9 Leading Alternative that is technically and economically feasible and should be
10 considered further. The main deliverable in the Conceptual Design stage is a
11 business case which describes the alternatives considered, the methodology
12 for evaluating those alternatives and the recommended Leading Alternative.
13 The recommended Leading Alternative is confirmed through the Leading
14 Alternative Identified Gate. Once this approval is provided, a conceptual design
15 level estimate is prepared, with an expected accuracy range of +100 per cent
16 and -35 per cent; and
 - 17 • **The Feasibility Design Stage** conducts the investigations and analysis
18 required to confirm that the Leading Alternative should be selected as the
19 Preferred Alternative, to be carried forward to the Preliminary Design Stage of
20 the Definition Phase. This analysis may include field and laboratory
21 investigations as well as further evaluation of First Nations interests,
22 environmental and other non-technical considerations. This analysis provides
23 the required detail to prepare plans for the Definition Phase and to develop a
24 feasibility design level estimate, with an expected accuracy range of
25 +50 per cent and -15 per cent. At the end of the Feasibility Design stage, an
26 updated business case is developed and a Preferred Alternative Gate is held to
27 confirm the Preferred Alternative. After the Gate, for projects with an Estimate
28 at Completion greater than \$50 million, the Executive Team reviews the
29 Preferred Alternative before it proceeds to the Board of Directors for approval.

6.4.7.8 Phase 3 in PPM Project Lifecycle: Definition (+15/-10 per cent)

The Definition Phase defines the major project components in sufficient detail to develop a Preliminary Design cost estimate with an accuracy range of +15 per cent and -10 per cent. In this phase, implementation funding and any required regulatory authorizations are obtained. In addition, the Project Manager verifies that sufficient input has been received from First Nations via engagement and/or consultation as well as from internal and external stakeholders. To complete the Definition Phase, the Statement of Objectives, the Project Plan for the Implementation Phase and the final Business Case are examined through the Full Funding Approval Gate. This Gate confirms that the risks associated with executing the work in the Implementation Phase are well managed and acceptable, before proceeding to that phase. After the Gate, for projects with an Estimate at Completion greater than \$50 million, the Executive Team reviews the Full Funding Approval request before it proceeds to the Board of Directors for approval. All projects greater than \$100 million are reviewed and approved by the BCUC.

6.4.7.9 Phase 4 in PPM Project Lifecycle: Implementation

The Implementation Phase consists of five stages: Detailed Design, Procurement, Construction, Commissioning and Acceptance, and Completion.

- The Detailed Design stage is the final stage in the design process. This stage refines the Preferred Alternative so that it can be represented in a manner that allows work to be procured, manufactured and constructed in accordance with objectives, requirements, industry standards and accepted practices. Drawings and specifications are prepared in this stage and depending on the scale of the project, several design reviews may be required.
- The Procurement Stage initiates the sourcing process and issues tenders or requests for bids and proposal documents. In this stage, contracts are awarded for the supply, installation and construction of required work.

- 1 • The Construction Stage develops, manufactures, supplies, installs and
2 constructs the required work in accordance with the contract specifications,
3 drawings, and criteria.
- 4 • The Commissioning and Acceptance Stage tests and commissions the
5 constructed facility or component in accordance with the prescribed criteria.
6 Once the facility or component has been successfully commissioned, accepted
7 and is fit for service, operational authority is transferred from the Project
8 Delivery KBU to the appropriate KBU within the Operations Business Group.
- 9 • During the Project Completion Stage, the Project Delivery KBU provides a list of
10 post-project commitments and conditions of permits, approvals and agreements
11 to the responsible KBU within the Operations Business Group. The final
12 deliverable in this stage is the project completion and evaluation report. Once
13 this report is accepted, the project is classified as complete.

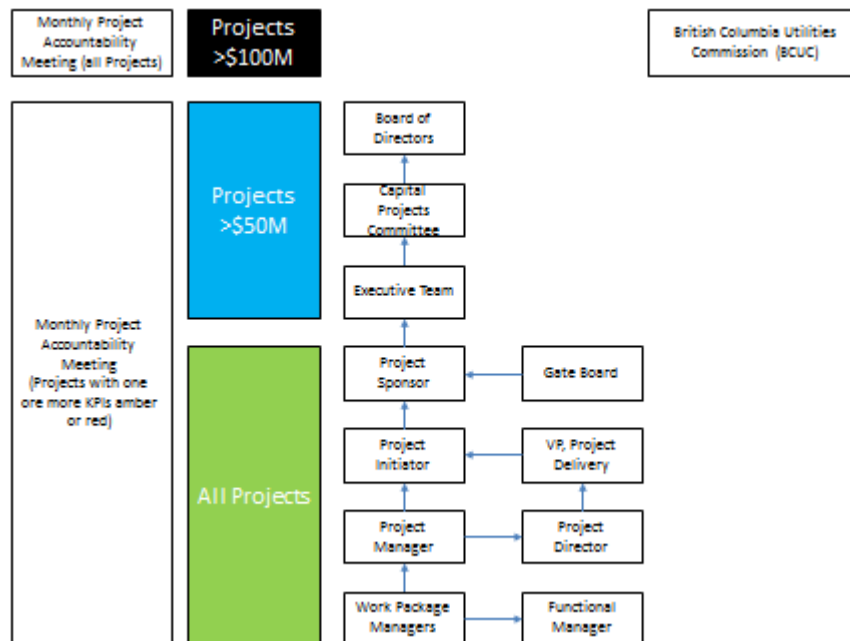
14 **6.4.7.10 Project Delivery Roles and Responsibilities are Well Defined**

15 Another important attribute of our project delivery process is that roles and
16 responsibilities are well-defined in advance. The process we employ streams
17 projects based on their size and complexity, with additional levels of oversight for
18 complex or higher risk projects.

19 BC Hydro deploys a matrix organization for resourcing and managing people
20 assigned to capital investments delivered by the Project Delivery KBU. This means
21 that staff are assigned to a project from various KBUs across the company to
22 perform the required roles. Staff can be assigned to a project on a full-time or
23 part-time basis and are accountable to the Project Manager for all project related
24 work and decisions. The Project Manager is responsible for the day to day direction
25 and decisions on the project. The KBUs that assign staff are responsible for setting
26 standards, process and practices for their staff, conducting training on those
27 practices and processes and for providing collegial support, approval of expenses
28 and performance management.

Figure 6-14 below illustrates the project governance structure for projects delivered by Project Delivery.

Figure 6-14 Project Delivery KBU - Project Governance Structure



The following provides a summary of the various roles within this governance structure;

- Work Package Manager:** The Work Package Manager is responsible and accountable for the planning and delivery of the Work Package within the approved scope, cost, and schedule as detailed in the Work Package Agreement. The Work Package Manager works with the Project manager and related Work Package Managers to create and develop the Work Package agreement (an element of the project scope);
- Functional Manager:** The Functional Manager is responsible for the review of the Work Package agreement with the Work Package Manager to assess expectations for resource needs and review assumptions, scope, deliverables, milestones and activities related to the Work Package Agreement;

- 1 • **Project Manager:** The Project Manager is responsible for leading the project
2 team to complete the objectives of the project. The Project Manager is
3 accountable to the Project Initiator to determine the need, justification and
4 objectives (scope, schedule and cost) of the project as well as to the Project
5 Delivery Director for the delivery of the project against approved objectives and
6 in accordance with approved policy and practice;
- 7 • **Project Delivery Director:** The Project Delivery Director is accountable to the
8 Vice President of Project Delivery and is responsible for the execution of the
9 projects in their portfolio against approved objectives and in accordance with
10 approved policy and practice. The Project Delivery Directors chair the gate
11 board meetings for projects with a cost of less than \$10 million;
- 12 • **Vice President, Project Delivery:** The Vice President, Project Delivery is
13 responsible for the delivery of the projects assigned to the Project Delivery KBU
14 and is accountable to the Senior Vice President of Capital Infrastructure Project
15 Delivery. The Vice President, Project Delivery chairs the gate board meetings
16 for projects with a cost of greater than \$10 million;
- 17 • **Project Initiator:** The Project Initiator is the person with the authority to initiate
18 work and is responsible for defining the work through the Statement of
19 Objectives and justifying the work through the Business Case. The Project
20 Initiator is also responsible for securing all required financial approvals. The
21 Project Initiator sets project requirements which are then translated by the
22 Project Manager into project scope, schedule and cost. The Project Initiator is
23 accountable to the Project Sponsor for the definition and justification of the
24 project; and
- 25 • **Project Sponsor:** The Project Sponsor supports the success of the project, by
26 approving the project and liaising with senior management. At Gate board
27 meetings, the Project Sponsor receives and considers Gate board
28 recommendations to decide whether to approve key project decisions.

The following committees provide oversight of projects and endorsement of project funding requests:

- Project Accountability Meetings:** BC Hydro conducts monthly Project Accountability Meetings to allow the Project Manager to update Gate Board members and internal stakeholders on the ongoing status of each project and provide a forum for participants to ask questions and deliver input and guidance. All projects with forecast capital costs greater than \$100 million and projects under \$100 million where one or more Project Key Performance Indicators are amber or red are reviewed monthly. The discussion at these meetings includes items such as project schedule, cost, scope, safety, operations, Indigenous relations, stakeholder engagement and project risks.

[Table 6-8](#) below identifies Project Accountability Meeting attendees.

Table 6-8 Project Accountability Meeting Attendees

Senior Vice President, Integrated Planning	Senior Vice President, Capital Infrastructure Project Delivery
Senior Vice President, Safety	Executive Vice President, Operations
General Manager, Engineering	Vice President, Project Delivery (<i>Chair</i>)
Director, Stations Asset Management	Director, Indigenous Relations
Director, Dam Safety	Director, Environment
Director, Line Asset Planning	Director, Properties
Director, Interconnections	Director, Line Field Operations
Director, Finance	Director, Stations Field Operations

- Gate Board Meetings:** Depending on the stage of the capital project, the project's estimated cost, scope, alternatives assessment, and implementation plans are subject to endorsement by a review at a Gate Board Meeting, before a funding request is approved. The Gate Board reviews the project to determine if it is ready to progress to the next stage of its lifecycle. In addition to funding and stage progression approvals, these meetings provide an avenue for

discussions with, and guidance from, key delivery partners on the status of projects and potential future issues.

As shown in [Table 6-9](#) below, there are two types of Gate Board Meetings, depending on the cost of the capital project:

Table 6-9 Types of Gate Board Meetings

Meeting Type	Capital Project Size
Major Gate Meeting	Projects ≥ \$10 million
Non- Major Gate Meeting	Projects < \$10 million

[Table 6-10](#) below identifies major and non-major Gate members.

Table 6-10 Major and Non-Major Gate Board Members

Major Gate Board Members	Non-Major Gate Board Members
Executive Vice President, Operations	Project Director(s) (<i>rotating chair</i>)
Senior Vice President, Integrated Planning	Manager, Project Environmental Risk Management
Senior Vice President, Capital Infrastructure Project Delivery	Manager, Indigenous Relations
Senior Vice President, Safety	Director, Stations Asset Planning
Vice President, Project Delivery (<i>Chair</i>)	Director, Dam Safety
Director, Environment	Director, Stations Field Operations
Director, Indigenous Relations	Director, Line Asset Planning
Director, Stations Asset Management	Director, Line Field Operations
Director, Dam Safety	Director, Interconnections
Director, Stations Field Operations	General Manager, Engineering
Director, Line Asset Planning	Finance Manager, Business Planning
Director, Line Field Operations	Capital Safety Manager
General Manager, Engineering	
Director, Finance	
Director, Properties	

The following additional governance roles are performed for all projects with a forecast cost greater than \$50 million:

- **Executive Team:** The Executive Team reviews the project to determine if the project is the appropriate response to the identified risk, issue or opportunity.

1 This review occurs at the end of the Identification Phase. The Executive Team
2 also conducts a review at the end of the Definition Phase to determine whether
3 the project is ready to proceed to the Implementation Phase, given the
4 assessment of residual risks. This review supports the recommendation for
5 approval to the Board of Directors;

- 6 • **Capital Projects Committee:** The Capital Projects Committee is one of the
7 standing committees of BC Hydro's Board of Directors. This committee assists
8 the Board of Directors in fulfilling its obligations and oversight responsibilities
9 related to the delivery of capital projects. Specifically, this includes, but is not
10 limited to, dam safety, the execution of long-term capital plans and budgets,
11 project oversight and relationships with First Nations. For capital projects with a
12 forecast cost greater than \$50 million, the Committee reviews the status of
13 capital projects during the Identification and Definition phases, reviews and
14 recommends the preferred alternative for approval by the Board of Directors,
15 following the completion of the Identification Phase, and reviews and
16 recommends financial approval by the Board of Directors, before the start of the
17 Implementation Phase. When making its recommendations to the Board of
18 Directors, the Capital Projects Committee reviews potential impacts to
19 Aboriginal rights and title as well as planned mitigations and considers whether,
20 in moving forward with a project, BC Hydro's consultations with First Nations
21 uphold the honour of the Crown. The Capital Projects Committee meets
22 quarterly in conjunction with the Board of Directors Meeting; and
- 23 • **Board of Directors:** BC Hydro's Board of Directors is appointed by and
24 accountable to the B.C. Government. The Board of Directors is responsible for
25 safeguarding BC Hydro's resources by approving annual operating and capital
26 budgets as well as individual capital projects with a forecast cost greater than
27 \$50 million. For these projects, BC Hydro has established processes in place to
28 facilitate Board of Directors review and approval of the preferred alternative,
29 following the completion of the Identification Phase, and financial approval, prior

1 to the start of the Implementation Phase. When considering approval, the Board
2 of Directors reviews potential impacts to Indigenous peoples as well as planned
3 mitigations and ensures that in moving forward with a project, the honour of the
4 Crown is maintained.

5 In addition to the roles and responsibilities described above, the BCUC provides
6 independent third-party review and approval of the need for projects greater than
7 \$100 million or of significant public interest, unless a project has been exempted by
8 government regulation. The BCUC also reviews the status of projects through
9 quarterly or semi-annual progress reporting, and may undertake a prudency review
10 of projects, once implementation is complete.

11 **6.4.8 We Use a Simplified Framework for Routine Power System** 12 **Investments**

13 The Program and Contract Management KBU is responsible for delivering less
14 complex and repetitive Power System capital investments on BC Hydro's power
15 system. The KBU is the single point of contact for the annual delivery of the
16 maintenance and small capital investment portfolio that is developed and optimized
17 by the Integrated Planning Business Group.

18 Approximately 26 per cent of planned capital investments in the Power System for
19 fiscal 2020 to fiscal 2021 will be delivered by Program and Contract Management.

20 When the annual maintenance and small capital investment portfolio is received
21 from the Integrated Planning Business Group, the Program and Contract
22 Management KBU develops annual program and project delivery plans in
23 collaboration with the KBUs in the Integrated Planning and Capital Infrastructure
24 Project Delivery Business Groups. This includes consideration of First Nations and
25 environmental issues. Internal resource commitments to deliver the work are
26 obtained from the Engineering, Distribution Design and Customer Connect, Line
27 Field Operations, Stations Field Operations and Construction Services KBUs.
28 Contracting plans are then developed to deliver the balance of the portfolio. Internal

1 FTEs are used to deliver a significant volume of the small capital work, with external
2 contractors being used to provide scalability due to fluctuations in
3 demand. Additional discussion on how Program and Contract Management delivers
4 work is provided in Chapter 5C, section 5C.4.

5 The capital investments delivered by Program and Contract Management are
6 typically “like for like” replacements of assets or system upgrades that are based on
7 pre-defined design standards, developed by BC Hydro’s Engineering KBU.

8 Examples of capital investments delivered by the Program and Contract
9 Management KBU include duct-bank construction, some end-of-life equipment
10 replacement and overhead line relocations within an existing or public right-of-way.

11 These investments are routine in nature, have a lower risk profile and require
12 minimal, if any acquisition of property or rights of way. The standardized nature of
13 these investments means that there are limited, if any alternatives to evaluate.

14 Standard procedures are established to select the most feasible alternative when
15 required.

16 These investments generally do not require specific equipment procurement and the
17 required materials are typically inventoried by BC Hydro’s Materials Management
18 department. When specialized services, equipment or materials are required,
19 standing blanket services contracts or master purchasing agreements are used.
20 Work is completed through unit-based contracts with external contractors.

21 The Program and Contract Management KBU applies a simplified version of the
22 PPM practices that is suited to the lower complexity of the projects it delivers. For
23 program investments that involve standardized units of work, the Program and
24 Contract Management KBU applies simplified work management processes.

6.4.9 We Use a Standardized Process for Routine Customer Driven Work

The Distribution Design and Customer Connections KBU is responsible for work related to customer requests for new or upgraded connections to BC Hydro's distribution system. This KBU provides technical design services and project management for customer driven new connections work, under 5 MW in size. More complex projects over 5 MW or over \$2 million in cost are managed by Program and Contract Management, with Distribution Design and Customer Connections providing design services. Approximately 16 per cent of the planned capital investments in the Power System for fiscal 2020 to fiscal 2021 will be delivered by the Distribution Design and Customer Connections KBU.

The Distribution Design and Customer Connections KBU designs to standards, with engineering support where required, and follows a project management structure that involves standardized work order packages, with environmental, archeological, safety and job planning processes and checklists. This simplified process enables project cycle times to align with customer requirements.

The Distribution Design and Customer Connections KBU issues approximately 5,000 work orders for new customer connections and 10,000 work orders for internal distribution growth and sustaining capital work programs each year. These work orders require design work and project coordination. A dedicated Express Connections Contact Centre within this KBU issues 35,000 express service orders per year. Express service orders are very simple customer connections which do not require design work.

While the Distribution Design and Customer Connections KBU plans for customer connections at a system level, individual customer connection projects depend on actual customer requests. Therefore, these projects are driven by customer timelines and are not planned in detail. Program volumes and characteristics are forecast based on historical trends. The staffing model for the Distribution Design and Customer Connections KBU includes full-time regular designers, full-time

temporary designers and contractor engineering resources to provide flexibility and to balance internal work program and customer program demands so that customer requests are prioritized for delivery to the agreed in-service dates.

6.4.10 Financial Approval Policies and Procedures Apply to All Capital Investments

BC Hydro has well established Management and Accounting Policies (**MAPP**) and Procedures and Financial Approval Authority Policy (**FAAP**) that set funding approvals required for capital investments through each phase of the project lifecycle. These approval requirements and processes have been developed to balance financial controls with operational efficiency, based on the nature and risk of the capital investments. The policies and procedures apply to all groups delivering BC Hydro's capital investments.

6.4.10.1 Company-Wide Approval Policies Are Documented

The policies that govern capital investment approvals are primarily included in:

- Management and Accounting Policies and Procedures 1.2.31A (Expenditure Authorization Requirements Policy);
- Management and Accounting Policies and Procedures 1.2.3B (Expenditure Authorization Requirements Procedure); and
- Management and Accounting Policies and Procedures 1.2.1B.2 (Financial Approval Authority Procedure).

The required financial approval processes set out in these documents depend on the type of capital investment. Capital investments are categorized into the following four main categories for financial approval processes:

- Phased Capital Projects;
- Non-Phased Capital Projects;
- Recurring Capital Investments; and

- Expenditure Authorization Request Exempt Capital Investments.

The financial approval processes for each category are discussed further in the sections below.

6.4.10.2 Phased Capital Projects Require Phase-by-Phase Funding Approval

For capital projects which are delivered using PPM phases, funding approval is required prior to the commencement of work for that stage or phase. Typically, funding is approved only for the next stage or phase once the required work for the prior stage or phase has been completed. The financial approver level is dependent on the stage or phase as well as the funding amount being requested. For projects that meet the BCUC thresholds for Certificate of Public Convenience and Necessity (CPCN) and section 44 reviews, applications are generally submitted to the BCUC during the Definition Phase.

[Table 6-11](#) below provides information on the funding approval process for phased capital projects, delivered by the Project Delivery KBU and Technology.

Table 6-11 Funding Approval Process for Phased Capital Projects (Project Delivery KBU)

Phase	Primary Budget	Estimate Accuracy Level	Funding Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Identification Phase (Needs Stage)	O&M (CPI) ³⁰⁴	N/A	- Annual Release Plan from Capital Plan - Maximum request is generally \$200,000	- Project Release Committee - No Finance Review	Amount requested	Director Project Delivery
Identification Phase (Conceptual Design stage)	O&M (CPI)	End of Stage provides +100% / -35%	- Statement of Objective (SOO) - If over \$2M, business case and Expenditure Authorization Request (EAR) Form also prepared	- Project Sponsor - Project Initiator - No Finance Review unless requested amount is more than \$2M	Based on cumulative O&M amount requested	Chief Operating Officer (COO): Up to \$50M Others: 25% of FAAP Planning limit
Identification Phase (Feasibility Design Stage)	Capital	End of Stage provides +50% / -15%	- SOO - Business Case - EAR Form	- Gate Board - Project Sponsor - Project Initiator - Finance Review required	Based only on amounts requested going forward	COO: Up to \$50M Others: 25% of FAAP Planning limit
Definition Phase	Capital	End of Stage provides +15% / -10%	- SOO - Business Case - EAR Form	- Gate Board - Project Sponsor - Project Approver - Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	COO: Up to \$50M Others: 25% of FAAP Planning limit
Definition Phase with Partial Implementation Phase costs (not including construction)	Capital	End of Stage provides + 15% / - 10%	- SOO - Business Case - EAR Form	- Gate Board - Project Sponsor - Project Initiator - Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	COO: Up to \$50M Others: 25% of FAAP Planning limit

³⁰⁴ CPI refers to Capital Project Investigation cost.

Phase	Primary Budget	Estimate Accuracy Level	Funding Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Partial Implementation Phase costs including construction	Capital	N/A	• SOO • Business Case or CPCN if applicable • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	Ultimate FAAP approver for total project estimate
Implementation Phase	Capital	N/A	• SOO • Business Case or CPCN if applicable • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	Ultimate FAAP approver for total project estimate

1 [Table 6-12](#) below provides information on the general funding approval process for
 2 phased capital projects delivered by other KBUs.

3 **Table 6-12 Funding Approval Process for Phased**
 4 **Capital Projects (Projects Delivered by**
 5 **Other KBUs)**

Phase	Primary Budget	Estimate Accuracy Levels	Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Identification	O&M	N/A or Various	• SOO or business case or equivalent • EAR form (Technology)	• Business group dependent • Finance Review dependent on amount requested and type of capital	Amount requested or based on Total Project Estimate (Technology)	COO: Up to \$50M Others: 25% of FAAP Planning limit
Definition	Capital	Various	• Business Case • EAR Form	• Business group dependent • Finance Review required	Cumulative amount being requested or based on Total Project Estimate (Technology)	COO: Up to \$50M Others: 25% of FAAP Planning limit
Implementation	Capital	Various	• Business Case • EAR Form	• Business group dependent • Finance Review required	Total Project Estimate	Ultimate FAAP approver for total project estimate

6.4.10.3 Non-Phased Capital Projects Require Business Case and Authorization

Non-Phased Capital Projects are capital investments that are not delivered using project phasing but are similar to a one-time capital investment. Examples include the purchase of new equipment or office furniture. For Non-phased capital investments over \$0.5 million, an approved business case and Expenditure Authorization Request (**EAR**) form are required prior to any capital spending. These authorization documents are approved based on the total investment amount, in accordance with BC Hydro's Financial Approval Authority Policy guidelines.

6.4.10.4 Recurring Capital Investments are Approved Annually

Recurring Capital Investments are generally completed each year, on an ongoing basis. This work is generally lower risk, involving like-for-like unit replacements, such as the annual distribution wood pole replacement program. These investments are authorized at the beginning of each fiscal year using the Recurring Capital Annual Expenditure Authorization Form.

6.4.10.5 Approved Work Orders Are Required for Low Cost Recurring Capital Projects

Expenditure Authorization Request Exempt Capital Investments are recurring capital projects with a low cost and high volume. Examples include work activities to connect distribution customers, which are required under the Electric Tariff and less than \$1 million in cost. These investments are operationally approved through BC Hydro's Work Order system. A business case is required for any projects with a forecast cost of more than \$1 million.

...

6.4.12 Forecast Capital Expenditures and Additions are Reduced to Account for Uncertainties

BC Hydro has applied a Portfolio Risk Adjustment to its fiscal 2020 to fiscal 2021 forecast capital expenditures and additions to account for the uncertainty in the schedule and cost of projects. As discussed in sections [6.4.7.5](#) to [6.4.7.8](#), the accuracy of forecast capital additions increases with the level of analysis and information on project scope, schedule and cost. Therefore, the largest uncertainties are associated with projects that are currently in early stages of the project lifecycle as their scope, schedule and cost are not as well defined as projects that are in later stages.

The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical project delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

As discussed in Chapter 7, section 7.8.2, any differences between the forecast and actual amortization of capital additions are captured in the Amortization of Capital Additions Regulatory Account. This means that the actual amount recovered from ratepayers is ultimately based on the actual capital additions.

...

6.5 Technology Capital Investments

The Technology KBU is responsible for the planning, design, delivery and operation of BC Hydro's information technology systems as well as a number of operational technology systems.

BC Hydro has made many improvements to the management of its technology capital program since the Previous Application. These improvements include:

- **Improved business case process:** Clear guidance is provided through the Technology business case development process so that business cases include alternative courses of action, comparison tables and trade-off analysis, as well as the articulation of financial and non-financial benefits, including metrics with baselines, targets, and details on how and when benefits are to be measured;
- **Improved program delivery governance:** Capital program delivery governance has been improved through ongoing monitoring by the Capital Delivery Management Committee. This process includes management of budget re-allocation and ex-plan requests, as described in section [6.3.5](#) above;
- **Improved delivery performance:** Our capital delivery performance has improved. From fiscal 2016 to fiscal 2018, a total of 94 projects were completed, with total approved first full funding of \$135.1 million and total actual costs of \$134.5 million - a favourable variance of \$0.6 million or 0.4 per cent. These variances are an improvement over the prior test period and compare favourably to industry results. The Project Management Institute's Pulse of the Profession Report stated in its global project management survey that 57 per cent of technology projects are completed on budget; and
- **New benefits realization process:** To address the BCUC's SAP Inquiry recommendations and to meet commitments made during the Previous Application proceeding, BC Hydro has developed a benefits realization process

for identification and tracking of benefits arising from business driven technology projects. This is described further in section [6.5.5](#) below.

6.5.1 Overview of Technology Capital Assets and Key Drivers

BC Hydro's business requires an extensive technology portfolio, and ongoing investment is critical. Our forecast investments fall into three categories, which correspond with the key drivers of technology investment:

- Manage compliance and security;
- Manage risk and sustain productivity; and
- Enhance business capability.

Each of these categories is explained further below.

6.5.1.1 Ongoing Technology Investment is Key to the Day to Day Operations of BC Hydro

BC Hydro's technology systems provide important support to the organization's day-to-day operations, and include data centres, networks, enterprise and business group applications, mobile phones and mobile applications, geographic information systems, personal devices and desktop software, cyber security devices and monitoring applications, business intelligence and analytics platforms, and a subset of the energy management systems.

Our technology assets are located in two active data centres and two control centres, which together hold approximately 2,500 servers as well as network switches, firewall components, storage and backup systems. Additional assets include software platforms and related licenses, approximately 300 applications and related licenses, approximately 8,200 desktop and laptop computers, and approximately 4,800 mobile phones. In addition, all major BC Hydro facilities have local area networks and BC Hydro has mobile WiFi in 900 fleet vehicles. These

assets are maintained through a combination of vendor product support agreements and sustainment investments.

6.5.1.2 *Fluctuations in Technology Investment Result from Project Timing, Emergent Priorities and Changes in Business Requirements*

While sustained investment in technology is required, the level of investment varies from year to year in response to project timing, emergent priorities and changes in underlying business requirements.

From fiscal 2016 to fiscal 2018, actual average annual Technology capital expenditures were \$75 million. Capital expenditures are forecast to be \$87.8 million in fiscal 2019 and are planned to be \$93.5 million in fiscal 2020. These increased amounts primarily reflect the implementation of the Supply Chain Applications project.

In fiscal 2021, planned capital expenditures decrease to \$55 million. This reflects a focus on investments to manage compliance and security and to manage risk and sustain productivity. Additional investments to enhance business capability, as identified and required, will be considered through funding re-allocations and the ex-plan process, which is further described in section [6.3.5](#).

6.5.2 Three Technology Investment Categories Correspond with Key Drivers

BC Hydro's Technology Strategy and Five-Year Plan, provided as Appendix L, provides guidance for capital investment in each of the three investment categories, described below. These categories correspond with the three main drivers of technology investment.

[Table 6-51](#) below summarizes the key capital investment drivers within each investment category.

Table 6-51 Technology Investment Drivers by Category

Category	Driver
Manage Compliance and Security	Regulatory Compliance (Compliance requirements) Investment requirement may come from regulatory bodies such as NERC, WorksafeBC, Canada Revenue Agency, etc. Reliability, safety or legislative requirements justify investment
	Product License Compliance (Contracts) Software licensing renewals or true-ups.
	Cybersecurity Risk (Excessive or increasing risk) Ever-changing threats and vulnerabilities
Manage risk and sustain productivity	Technology Condition-Based Failure Risk (Declining condition) Declining asset health increases asset failures. When the consequences are considered (under business-as-usual), a risk profile can be assessed, and value of risk mitigation may justify investment.
	Technology Performance-Based Risk (Declining performance) Obsolescence and declining utilization affect performance. When the consequences of performance problems are evaluated (under business-as-usual), a risk profile can be assessed, and value of risk mitigation may justify investment.
	Operational Risk (Excessive or increasing risk) Safety, Reliability, Environmental or Financial risk may justify investment.
	Reputational Risk (Excessive or increasing risk) Excessive or increasing reputational risk may justify investment.
	Business Growth (Increasing need for technology services) Expansion of technology services through load growth or higher demand for existing services.
Enhance Business Capability	Enhanced Capability (Need for new or significantly improved business function) Demand for new capabilities enabled by technology, typically related to automation, business intelligence, communications, and new services.

6.5.3 Technology Capital Investment Planning

Technology capital investment planning includes both top-down and bottom-up processes. The Technology capital plan is guided by the top-down planning process described in section [6.3.2](#) and is included in the Enterprise planning and prioritization process, discussed in section [6.3.4](#).

BC Hydro developed the capital investment portfolio for the fiscal 2020 to fiscal 2021 test period using a three-step planning process. This process is designed to ensure our investments are in line with our priorities; that benefits, costs and risks justify investment, and that we are able to deliver on our plans. The process has been improved over the prior test period and future improvements are expected.

6.5.3.1 Step 1 – Identification of Investments

First, investments are identified for inclusion in the portfolio plan. The portfolio plan consists of active investments and new initiatives. Active initiatives are investments initiated in previous years and continue to be tracked through the various stages of execution. New initiatives are based on investment proposals. Each initiative is captured within the portfolio plan as a project, work program or acquisition. Each portfolio entry includes the name, description, prioritization assessment, investment score as well as forecast costs and risks and is accompanied by an Investment Justification document.

6.5.3.2 Step 2 – Formation of Draft Portfolio Plan

Second, once the capital portfolio entries have been fully captured and detailed, a draft portfolio plan is developed. Proposed initiatives are classified as mandatory, committed or prioritized and are then prioritized and subjected to constraints.

- **Mandatory initiatives** are required to meet security, safety, legal, regulatory or tariff compliance, and are not considered for prioritization.
- **Committed initiatives** are active investments and have either proceeded to the implementation phase, or are substantially committed as of the planning date. These initiatives are generally not considered for prioritization, due to cost or risk of undertaking a change in scope or schedule.
- **Prioritized initiatives** are prioritized using the enterprise-wide framework for capital prioritization, discussed in section [6.3.4](#) and by a technology specific investment score. These scores provide guidance into the development of the portfolio plan, within the enterprise funding allocation.
- **Constraints** include delivery and oversight capacity, business capacity for change, support capacity, technical dependencies and technology maturity. Time may also be a constraint, particularly if risk is expected to escalate, a window of opportunity exists, and/or if there are unmet dependencies.

6.5.3.3 Step 3 - Review, Refinement and Finalization

Third, a series of reviews are conducted on the draft portfolio plan to facilitate dialogue amongst Technology KBU management staff and affected BC Hydro business stakeholders. These reviews consider factors such as strategic alignment, portfolio value and risk and may result in the re-assessment of specific investments, re-design of programs or projects or shifting of timelines.

The Technology capital portfolio plan is dynamic in nature, and actual capital investments in the test period will likely differ for a number of reasons, including:

- Early stage Technology investment proposals include estimates which have a higher degree of uncertainty relative to later-stage business case estimates as technology choice, solution scope and scale, design and timing have not yet been fully examined; and
- Emerging and changing business priorities may require new technology solutions. For example, unplanned technology outages, increased technology risks, and unexpected loss of vendor support for products or services can all impact actual technology investments.

The Technology KBU oversees the implementation of its annual capital plans through monthly capital committee meetings of the Technology KBU leadership team. These committee meetings review portfolio plan variances, reallocate capital as needed, and manage risk adjustments.

6.5.4 Technology Portfolio Delivery Has Been Improved

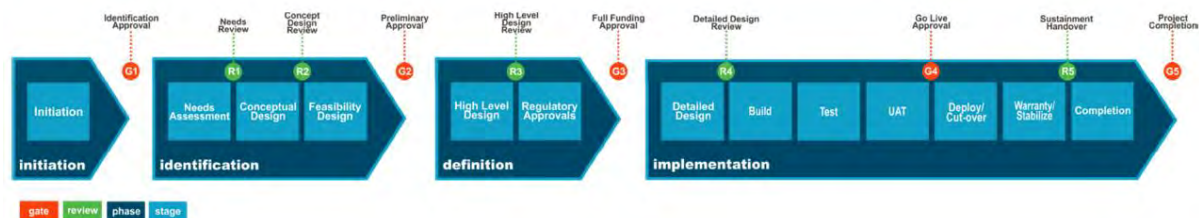
The capital investment portfolio consists of projects, work programs and acquisitions. Investments require approved business cases and adhere to a Technology-specific delivery framework called Information Technology Delivery Standard Practices (ITDSP).

6.5.4.1 We Use a Standard Technology Project Delivery Framework that Requires Approvals at Each Phase

ITDSP is used to aid managers, service providers and project teams in delivering successful technology projects. This framework was adopted in 2004 and is updated annually. The framework aligns with PPM Practices, which are discussed further in section [6.4.7](#) above, and has been adapted to better support the unique character of technology projects.

ITDSP uses standard PPM phases with uniquely defined stages. Gate approval points are positioned at the end of project stages so that management can confirm that the proposed project solution remains in alignment with business drivers, and is ready to progress to the next phase or stage. Each gate is a formal approval point, where key information is presented to the gate board, typically related to cost, schedule, scope, procurement, and risk.

Figure 6-16 Project Lifecycle Sequence from Project Initiation to Completion



The following sections provide a high level summary of the key activities within the project lifecycle phases.

6.5.4.2 Initiation Phase

The primary objective of the Initiation phase is the prioritization of a specific initiative and the decision to prepare a business case. To support the decision to initiate a project, the Project Initiator is responsible for assembling the following information:

- Brief description of the Problem or Opportunity;

1 • Key business drivers and any associated risks; and

2 • Estimated funding needs.

3 A decision is made to form and proceed with a project based on:

4 • The understanding of the problem or opportunity and the risk to the business;

5 • Support by the Project Initiator;

6 • The funding requirement; and

7 • The potential funding source.

8 The key outcomes of the Initiation phase are:

9 • An Identification phase business case;

10 • A detailed Identification phase project plan; and

11 • Firm Identification phase costs as well as an initial estimate on the overall
12 project cost.

13 The Initiation phase concludes when the Identification phase business case is
14 approved.

15 **6.5.4.3 Identification Phase**

16 The Identification phase includes three stages:

17 • **Needs Assessment** – to confirm the scope and business requirements.

18 • **Conceptual Design** – to review alternative solutions and select the leading
19 alternative.

20 • **Feasibility Design** – to evaluate the feasibility of alternative solutions and
21 recommended an alternative to be taken forward to the Definition phase.

The key outcomes of the Identification phase are:

- Approved and prioritized business requirements;
- An assessment of alternative solutions including a recommended solution and confirmed feasibility of the recommended solution;
- Completion of a Process Impact Assessment;
- A Definition phase business case;
- A detailed Definition phase project plan; and
- A firm Definition phase cost as well as a refined range estimate for the overall project cost.

The Identification phase concludes when a decision is made on whether to proceed to the Definition phase (the Preliminary Approval Gate).

6.5.4.4 Definition Phase

The Definition phase includes two stages:

- High Level Design/Blueprint; and
- Regulatory Approvals³¹²

The objective of the Definition Phase is to carry out a detailed investigation of the selected alternative as well as to prepare a high level design, project implementation plan and an estimate of the Implementation phase funding, including an Implementation phase business case. This phase also includes securing all required regulatory approvals as well as any key defining agreements.

The key outcomes of the Definition phase are:

³¹² Based on BC Hydro's current proposal in the Capital Expenditure Review Proceeding, the threshold for regulatory approvals is an estimated overall budget equal to or greater than \$20 million. In these cases, the Project Managers work closely with the Regulatory and Rates KBU to receive regulatory advice.

- Process maps and definition documents;
- A High Level Design/Blueprint (documented in the Architecture Definition Document);
- An Implementation phase business case;
- An Implementation project plan; and
- A firm overall cost estimate range to complete the project.

The Definition phase concludes when a decision is made on whether to proceed to the Implementation Phase (the Full Funding Approval Gate).

6.5.4.5 Implementation Phase

The Implementation phase includes seven stages:

- Detailed Design;
- Build;
- Test;
- User Acceptance Testing
- Deploy/Cut-over;
- Stabilize; and
- Completion.

The objective of the Implementation phase is to complete the detailed design, build, test and commission the solution into service.

The key outcomes of the Implementation phase are:

- A working solution, confirmed through testing, that meets project objectives and is fully transitioned into operation; and

- A Project Completion Report measuring success against the approved business case.

The Go Live Approval Gate represents a decision on whether to proceed to the Deploy/Cut-over stage.

The project is considered complete once the Project Initiator and Project Sponsor have accepted the project results by signing the Project Completion and Evaluation Report.

6.5.4.6 *Technology Work Programs and Licenses Are Subject to Work Flow Approval Processes*

A Work Program is a program of high volume sustainment or enhancements items, typically with a low cost per item, which utilizes simple work flows on highly standardized and repeatable work units to deliver an overall benefit. Work Programs are typically set up for one fiscal year at a time, for a specific asset or group of assets. As this work is less complex, the ITDSP framework and project life cycle do not apply. Similarly, capital purchases for licences and equipment are also not subject to the ITDSP framework as they are not projects.

6.5.4.7 *We Optimize Internal and External Resources*

Technology employs two primary delivery models to optimize the use of internal and external market-based delivery capacity:

- Projects are primarily delivered through managed teams, where BC Hydro staff or consultant project managers manage blended teams of employees, vendors and individual contractors; and
- For larger, more complex projects, BC Hydro uses an outsourced model, called the system integrator model, where teams of external service providers provide project delivery and a large number of developer resources are applied to a project.

1 This resourcing model is appropriate to deliver the capital plan in the test period. The
2 use of blended teams and system integrators allows for rapid scaling of our
3 workforce, as required.

4 **6.5.4.8 Technology Project Delivery Governance**

5 Governance of technology capital delivery is provided by project steering
6 committees, project gate reviews and funding approval, the Executive Team and the
7 Board of Directors.

- 8 • Project steering committees provide senior management level direction to
9 projects to assist with resolving complex issues.
- 10 • Project gate reviews occur at various points of the project lifecycle. Each gate is
11 a formal approval point where key information on project cost, schedule, scope,
12 procurement and risk is presented to the gate board.
- 13 • The Executive Team reviews the delivery portfolio on a monthly basis and
14 approves projects greater than \$6 million.
- 15 • The Board of Directors approves projects greater than \$20 million.

16 Governance is also provided through BC Hydro's Management and Accounting
17 Policies, which are discussed in section [6.4.10](#).

18 **6.5.4.9 Our Technology Project Delivery Performance Has Improved and** 19 **Compares Well to Industry Results**

20 [Figure 6-17](#) and [Table 6-52](#) below provide a summary of BC Hydro's performance in
21 delivering technology capital projects by comparing total approved first full funding
22 for projects to total actual project costs.

Figure 6-17 Number of Technology Projects Completed Within Total Approved First Full Funding Amount

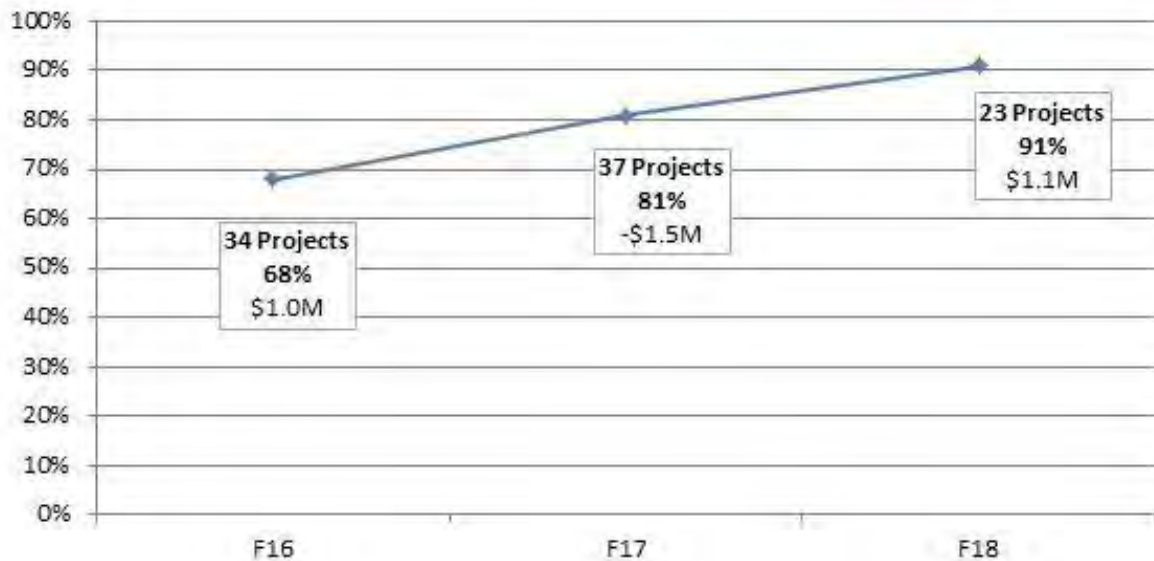


Table 6-52 Number of Technology Projects Completed Within Total Approved First Full Funding Amount

Fiscal Year	No. of Initiatives completed	Percentage of Initiatives Completed within FFF Amount	Cumulative Initiative Cost (\$ million)		Variance	
			[A] FFF Amount (\$ million)	[B] Actual Final Cost (\$ million)	[A – B] (\$ million)	[(B – A)/A] (%)
2016	34	68	42.0	41.0	1.0	2.4
2017	37	81	59.6	61.1	(1.5)	(2.5)
2018	23	91	33.5	32.4	1.1	3.3
Total	94		135.1	134.5	(0.6)	(0.4)

From fiscal 2016 to fiscal 2018, a total of 94 projects were completed, with total approved first full funding of \$135.1 million and total actual costs of \$134.5 million - a favourable variance of \$0.6 million or 0.4 per cent.

These results indicate improvement over the period and compare favourably to industry results. The Project Management Institute's Pulse of the Profession Report

1 stated in its global project management survey that 57 per cent of technology
2 projects are completed on budget.

3 **6.5.5 We Have Introduced a Technology Benefits Realization Process**

4 Once a technology project is complete, newly implemented technology capabilities
5 are expected to yield desired business outcomes and measurable benefits. These
6 benefits may be diverse and apply to multiple KBUs. They may occur immediately or
7 over time. BC Hydro has developed a benefits realization process so that benefits
8 claimed in business cases are tracked and realized.

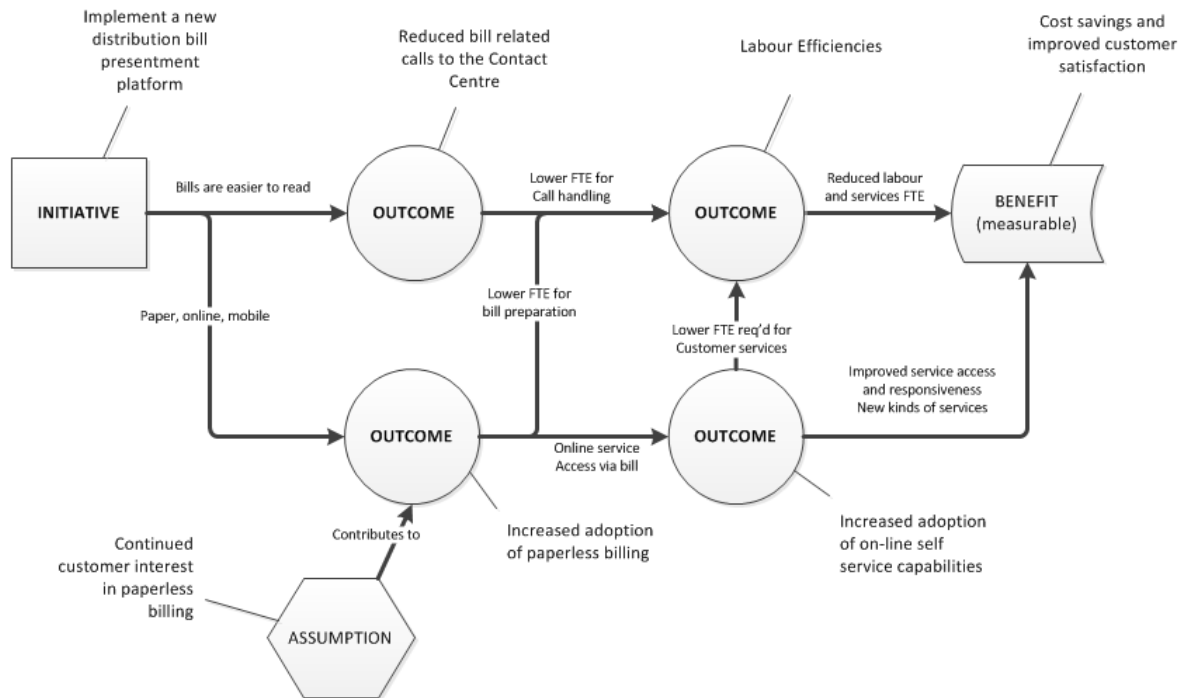
9 Each technology project has a business case which articulates the need, desired
10 outcomes, and expected incremental benefits and costs. Cost estimates include
11 upfront and ongoing costs, and expected benefits typically include risk mitigation and
12 improved performance.

13 The use of financial measures such as net present value or return on investment
14 may suggest certainty of financial benefits. For this reason, benefits are not often
15 quantified in dollars, but are assessed using specific metrics that are easier to
16 identify, predict and measure. The sponsor of each business case agrees to the
17 costs and benefits outlined, including the timing of costs and benefits and how they
18 will be measured.

19 This benefits realization methodology is being piloted on a number of BC Hydro's
20 non-mandatory, business-driven technology initiatives with expected capital
21 expenditures greater than \$2 million. Selected benefits identified in each business
22 case are tracked over the life of the asset, for an agreed period of time, or until all
23 material benefits have been realized. Project initiators are required to document
24 completion of outcomes and achievement of benefits on a quarterly basis, during
25 project implementation and following project completion.

[Figure 6-18](#) below provides an example of this approach. In this example, an initiative to implement a new distribution bill presentation platform results in a series of outcomes leading to measurable cost savings and improved customer satisfaction.

Figure 6-18 Benefit Realization Outcome Model (Illustration Only)



The actual outcomes and benefits from operation of a technology asset are tracked over a number of years.

[Table 6-53](#) below identifies the projects selected for this benefits realization pilot in fiscal 2018. The pilot will continue, with additional projects in fiscal 2019 and throughout the test period.

1
2**Table 6-53 Benefits Realization Pilot Projects
(Fiscal 2018)**

Project	Status
Enterprise Billing Infrastructure Project (EBIP)	In Service
Field Access to Safety Information (FASI)	In Service
Fleet and Garage Management System (FGMS)	In Service
Supply Chain Applications (SCA)	Delivery

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6.6 Properties Capital Investments

The Properties KBU is responsible for the supply, operations and maintenance of BC Hydro's headquarters and field offices, which total 101 facilities, comprising approximately 3 million square feet of office and industrial space. These facilities house field crews as well as a wide range of critical functions including system operations, telecommunications, emergency operations, customer contact, materials management, fleet management, and security command centers. BC Hydro's headquarters and field offices provide critical services to BC communities and local industry and must be operational for 24-hour response in all conditions, similar to

other emergency services facilities (e.g., fire halls). Facilities managed by the Properties KBU do not include Generation plant buildings or Transmission and Distribution substations, which are included in the Generation and Transmission and Distribution capital plans, respectively.

6.6.1 Properties Portfolio Investments Address Risks and Issues with Existing Assets

The investments in the Properties portfolio are driven by the need to address the issues and risks associated with the existing physical assets and infrastructure. Properties capital investments fall into two general categories:

- **Building Development** - projects include the major refurbishing or rebuilding of field buildings in areas where BC Hydro's existing facilities are at end of life and/or inadequate to meet operational needs; and
- **Building Improvement** - projects at existing facilities to address operational deficiencies as well as end-of-life replacements of aging building components and systems.

Properties Capital Planning focuses on assessing the health of existing assets and determining operational requirements that cannot be met by the existing asset portfolio, to establish an effective long term capital plan.

Aging Assets

Facilities managed by Properties are, on average, 33 years old, with more than forty per cent of the facilities being greater than 40 years old. Continued investment in these assets in the test period and beyond is required to maintain efficient and effective operation of BC Hydro's building assets, to limit costly and disruptive failures and to achieve the organization's objectives. All Properties' projects are classified as Sustaining Capital.

Asset Health

Properties assesses the health of more than 12,000 individual assets at the 101 BC Hydro facilities managed by Properties, based on each asset's current condition (including each facilities seismic withstand), remaining life expectancy, likelihood of failure, and impact of failure. These assets include building envelopes, roofs, HVAC systems, elevators, etc. The results of these assessments identify assets that are at or near end of life. Investments in these assets are considered for inclusion in the capital plan.

Operational Requirements

Properties seeks feedback from key occupant groups in order to capture each group's building-related requirements across the portfolio. These occupants assess their facilities for their ability to meet their operational priorities. This feedback results in proposed investments to address specific operational demands including, for example, inadequate office and operational space, insufficient material storage space, and undersized truck bays.

6.6.2 Properties Bottom – Up Asset Capital Planning Process

The Properties planning process follows a three step bottom-up approach.

Step 1 – Identify the Asset Needs

The first step of this process is to identify the building and asset needs at each of the facilities that should be considered for remediation. This assessment includes reviews of existing asset issues and risks as well as asset condition assessments. This results in a list of proposed projects.

Step 2 – Formation of a Draft Capital Plan

The proposed projects are categorized, ranked by priority and then subjected to any funding constraints, in order to develop a draft capital plan.

Step 3 – Review the Investments in the Capital Plan Period

The draft plan then undergoes a series of reviews of the planned investments across the building portfolio to ensure that investments are appropriately prioritized and timed. This review also allows for validation of the operational requirements by Properties and BC Hydro operations and other KBUs. These reviews may result in a re-assessment of specific projects, or shifting of projects within or beyond the capital plan period.

Properties proposed capital investments are subject to the BC Hydro enterprise-wide framework used to assist in prioritizing capital investment. Investments included in the BC Hydro 10 Year Capital Forecast are selected based on their prioritization score and other constraints, following the BC Hydro enterprise-wide process. Further information is provided in section [6.3.4](#) above.

Additional information on the Properties capital expenditures for the fiscal 2020 to fiscal 2021 test period is provided in Appendix I, page 10, lines 1 to 7 and Appendix J, pages 123 to 127.

6.6.3 Properties Capital Investment Delivery Aligns With BC Hydro's Standard Approach

The Properties Group will deliver approximately \$114 million of BC Hydro's capital expenditures over the test period. The delivery of Properties' capital projects are managed using both internal and external (contracted) resources following normal building construction industry practices. Properties' Capital Delivery processes align with the standard BC Hydro project lifecycle for managing projects, whereby:

- Projects progress through the four phases of delivery: Initiation, Identification, Definition, and Implementation; and
- Gate approvals are formal approval points positioned at the end of key stages in the project lifecycle to allow management to confirm that the proposed

- 1 project solution remains in alignment with business drivers and that the project
- 2 is delivering on key project objectives including cost, schedule, and scope.

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6.7 Fleet Capital Investments

Fleet is responsible for the acquisition, operational costs, maintenance and disposal of BC Hydro's 3,600 vehicle, trailer and equipment assets relied on by field crews and staff across the province to complete the organization's maintenance and capital work programs and support system reliability. The safety, reliability, and availability of vehicles and equipment are critical to ensure BC Hydro employees are able to safely and efficiently complete diverse types of planned and unplanned work, including restoration work during storms and emergencies.

6.7.1 Fleet Investments Are Managed Using Established Industry Principles and Practices

BC Hydro manages the lifecycle of diverse vehicle and equipment assets using established fleet industry principles and practices. These vehicle and equipment assets include light vehicles (cars, SUVs, pickups and compact vans), medium vehicles (flat deck and service body trucks, walk-in and heavy vans), heavy vehicles (bucket trucks, digger derricks, cranes, heavy flat decks, tractors, fire trucks, and dump trucks), trailers, forklifts, and other types of equipment (herein referred to as vehicles and equipment). The present average age of fleet assets is 5.9 years, with expected planned vehicle and equipment lifespans ranging from 10 to 15 years depending upon asset class.

6.7.2 Fleet Portfolio Investments

Investments in fleet assets are made to sustain reliable operations across the province, minimize total asset lifecycle costs, ensure fitness of given assets for evolving work purposes, and limit safety and operational risks by meeting safety and other regulatory requirements.

6.7.2.1 Vast Majority of Fleet Investments Are Replacements Rather than Upgrades

Fleet investments can be of two major types:

- Replacement of end-of-life vehicles and equipment to reduce financial risks, control lifecycle costs and address age-related mechanical, safety and reliability issues. These sustaining investments form the vast majority of the Fleet capital plan and seek to avoid financial risk of increasing maintenance costs as assets age, including the higher likelihood of costly unplanned maintenance events. It is important to continually maintain the composition of the fleet from the standpoint of average age in order to limit the build-up of high cost, older vehicles and equipment.

- Providing additional or upgraded fleet assets to improve operational productivity, flexibility and safety. This represents a very small portion of fleet capital investments and includes value-based vehicle and equipment purchases via the upgrading or the addition of new assets in response to changing business needs and work methods.

6.7.3 Fleet Assets Capital Planning Has Balanced Affordability and Operational Needs

Fleet Investment Capital Planning for the test period was guided by the principle of balancing affordability and vehicle reliability, while providing support to operate our system safely.

In its capital planning process, BC Hydro identifies and ranks vehicles and equipment for replacement using asset information (asset age/remaining life, mileage, maintenance costs, utilization rates, observed downtime frequency), input from fleet maintenance staff and end-users on asset condition, criticality and operational requirements. End-users also can identify requirements for upgraded or additional fleet assets. This information is used to assemble a list of vehicles and equipment for acquisition planning. The process is initiated in advance of the expected end-of-life replacement criteria (i.e., for a vehicle with a ten-year life replacement planning is started at approximately the seven year mark). The general fleet replacement criteria are established based on historical data, as well as the suggested useful life in a commercial application as determined by BC Hydro fleet data, industry benchmarks and vehicle manufacturers. In addition, the work application and the environmental conditions in which the assets are operated are considered as they have an impact on the actual life of the vehicle.

Through the Application of the enterprise-wide framework for capital prioritization, top-down planning and expenditure guidelines and other constraints, the list of vehicles for replacement, upgrades and vehicle additions are prioritized. Recommended acquisition plans are vetted through senior management.

1 During the test period, BC Hydro is planning to keep some fleet assets in service for
2 longer periods, which will increase the average age of BC Hydro's fleet. The
3 objective of this approach is to maximize the value of our existing assets to balance
4 affordability and vehicle reliability. While increased asset age is expected to impact
5 the overall condition of fleet assets, creating risks such as lower vehicle reliability
6 and higher maintenance and operating costs, actions such as timely completion of
7 routine preventative maintenance, implementation of fleet telematics and the
8 creation of additional vehicle pools to increase asset utilization will help to mitigate
9 these risks.

10 To-date, fleet aging has not resulted in a corresponding decline in BC Hydro's
11 overall system performance or customer reliability. If BC Hydro begins to experience
12 an unacceptable increase in fleet asset failures, options include adjusting the level of
13 end-of-life replacement by redirecting funding from other parts of the BC Hydro
14 capital investment portfolio or changing operational or maintenance practices.
15 BC Hydro reviews its capital plan on a regular basis, providing an ongoing
16 opportunity to adjust capital investments in order to respond to new information,
17 including system performance, asset health and risks.

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BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix T Reliability Indices

**Fred James**

Chief Regulatory Officer

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Fax: 604-623-4407

bchydroregulatorygroup@bchydro.com

May 4, 2020

Mr. Patrick Wruck
 Commission Secretary and Manager
 Regulatory Support
 British Columbia Utilities Commission
 Suite 410, 900 Howe Street
 Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

**RE: British Columbia Utilities Commission (BCUC or Commission)
 British Columbia Hydro and Power Authority (BC Hydro)
 Annual Reporting of Reliability Indices
 Annual Response to Directive 26 of BCUC Decision on F2005/F2006
 Revenue Requirements Application (F05/F06 RRA)**

BC Hydro writes as required by Directive 26 of BCUC Order No. G-96-04 on BC Hydro's F2005 to F2006 Revenue Requirements Application to provide an annual reporting of reliability indices.¹

Directive 26 states that BC Hydro is expected to present reliability indices (SAIFI, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forced outages, availability, and generation outage rates) both combined and disaggregated (where applicable) on an annual basis with comparisons to Canadian Electricity Association (**CEA**) averages.

In this filing, BC Hydro is providing reliability indices for distribution, transmission and generation performance through F2020. As in previous years, BC Hydro reliability statistics are provided on a fiscal year basis and compared with the CEA calendar year data.

¹ BC Hydro submitted its initial distribution and generation reliability indices compliance filing in September 2005, and subsequently reported the available reliability indices in May 2006 as part of the F2007/F2008 RRA. Starting in May 2007, BC Hydro began filing annual reports with the Commission on these reliability indices. Transmission system reliability indices for the years prior to F2012 were provided separately by the British Columbia Transmission Corporation (**BCTC**) in its Transmission System Capital Plan filings. BC Hydro provided the transmission system reliability indices starting in F2012, subsequent to the integration of BC Hydro and BCTC in F2011.

May 4, 2020
Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Annual Reporting of Reliability Indices
Annual Response to Directive 26 of BCUC Decision on F2005/F2006 Revenue
Requirements Application (F05/F06 RRA)



Page 2 of 2

Distribution and Transmission Update

The most recent annual CEA reports for distribution and transmission are the 2018 Annual Service Continuity data on Distribution System Performance in Electrical Utilities and the Bulk Electricity System. CEA data on distribution and transmission performance for the 2019 calendar year are not yet available. The comparative reliability indices, both combined and disaggregated for BC Hydro's distribution and transmission systems, are presented in Attachment 1, in tabular and graphical form through to F2020.

Generation Performance Update

The most recent annual CEA report on generation performance is the 2018 Generation Equipment Status Annual Report. CEA data on generation performance for the 2019 calendar year are not yet available. The comparative reliability indices, both combined and disaggregated for BC Hydro's generation system are presented in Attachment 2, in tabular and graphical form for the ten-year period ending F2020.

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

A handwritten signature in black ink, appearing to read "Fred James", written over a white background.

Fred James
Chief Regulatory Officer

Is/ma

Enclosure

**F05/F06 Revenue Requirements Application
Annual Response to Directive 26 of BCUC Decision**

F2020 Annual Reporting of Reliability Indices

Attachment 1

Distribution and Transmission Reliability Indices

This section includes the following distribution and transmission indices:

SAIFI	a measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in a year
T-SAIFI-MI	a measure of transmission interruptions of less than one minute in duration that a delivery point experiences in a year
T-SAIFI-SI	a measure of transmission interruptions of one minute or more that a delivery point experiences in a year
T-SAIDI	a measure of the average total interruption duration, in hours that a delivery point experiences in a year
SAIDI	a measure of the amount of time, in hours, an average distribution customer is without power in a year
CAIDI	a measure of the average interruption, in hours, per interrupted distribution customer in a year
%SAI	a measure of the percentage of time service is available in the year
CEMI-4	percentage of customers experiencing four or more outages in a year
MAIFI	a measure of the frequency of momentary (less than one minute) interruptions per distribution customer served in a year
DPUI	a measure of overall bulk electricity system performance in terms of a composite index of unreliability expressed in system minutes in a year. It takes into account all forced and planned outages except interruptions attributed to generators
SARI	a measure of the average restoration time, in hours, for each transmission delivery point in a year

As noted in Provision 9x of the F2011 Revenue Requirements Application Negotiated Settlement Agreement, BC Hydro is also reporting its CEMI-4 reliability metric, and SAIFI, SAIDI, CAIDI, ASAI, and CEMI-4 metrics normalized using the IEEE 2.5 Beta method. CEMI-4 is not benchmarked externally as utilities are at varying stages in their development of this metric.

**Table 1 Reliability Indices – BC Hydro Overall and CEA Overall
(All-Event Indices, Not Normalized)**

Year	BC Hydro Overall				CEA Overall			
	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F2011	1.89	5.28	2.80	99.940	2.20	5.17	2.35	99.941
F2012	1.92	5.08	2.65	99.942	2.63	6.16	2.34	99.930
F2013	1.59	3.70	2.33	99.958	2.54	4.66	1.83	99.947
F2014	1.83	5.19	2.83	99.941	2.72	9.49	3.49	99.892
F2015	1.72	5.11	2.97	99.942	2.39	6.38	2.67	99.927
F2016	2.29	10.69	4.66	99.878	2.32	5.08	2.19	99.942
F2017	2.17	5.50	2.53	99.937	3.10	5.65	1.82	99.936
F2018	2.13	6.56	3.08	99.913	2.61	7.91	3.04	99.910
F2019	1.90	8.58	4.51	99.902	2.84	8.46	2.98	99.903
F2020	1.96	4.78	2.44	99.945	n/a	n/a	n/a	n/a

**Table 2 Reliability Indices – BC Hydro (Distribution)
and CEA (Distribution)
(All-Event Indices, Not Normalized)**

Year	BC Hydro (Distribution)				CEA (Distribution)			
	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F2011	1.43	4.77	3.34	99.946	1.74	4.65	2.67	99.947
F2012	1.37	4.40	3.22	99.950	2.09	5.59	2.68	99.936
F2013	1.06	3.08	2.92	99.965	1.86	4.13	2.22	99.953
F2014	1.45	4.66	3.20	99.947	2.05	8.59	4.19	99.902
F2015	1.34	4.44	3.31	99.949	1.79	5.67	3.16	99.935
F2016	1.91	10.13	5.30	99.884	1.79	4.54	2.53	99.948
F2017	1.74	4.83	2.77	99.945	2.44	5.08	2.08	99.942
F2018	1.69	5.82	3.44	99.934	2.05	5.33	2.60	99.939
F2019	1.63	8.08	4.95	99.908	2.23	7.16	3.21	99.918
F2020	1.41	3.83	2.71	99.956	n/a	n/a	n/a	n/a

**Table 3 Reliability Indices – BC Hydro Overall –
Normalized using IEEE 2.5 Beta Method**

Year	BC Hydro Overall – Normalized using IEEE 2.5 Beta method				
	SAIFI	SAIDI	CAIDI	CEMI-4 (%)	%ASAI
F2011	1.61	3.83	2.38	15.26	99.956
F2012	1.67	3.89	2.34	15.37	99.956
F2013	1.46	3.33	2.28	10.45	99.962
F2014	1.68	4.14	2.46	12.52	99.953
F2015	1.35	3.37	2.49	10.13	99.962
F2016	1.60	3.42	2.14	14.00	99.961
F2017	1.88	4.37	2.33	16.43	99.950
F2018	1.67	3.94	2.36	14.55	99.955
F2019	1.39	3.21	2.32	10.65	99.963
F2020	1.68	3.56	2.12	14.59	99.959

**Table 4 Reliability Indices – BC Hydro CEMI-4 Overall
(All-Event Indices, Not Normalized)**

Year	BC Hydro Overall
	CEMI-4 %
F2011	19.26
F2012	17.43
F2013	12.88
F2014	15.10
F2015	15.15
F2016	23.77
F2017	19.45
F2018	20.87
F2019	17.14
F2020	18.39

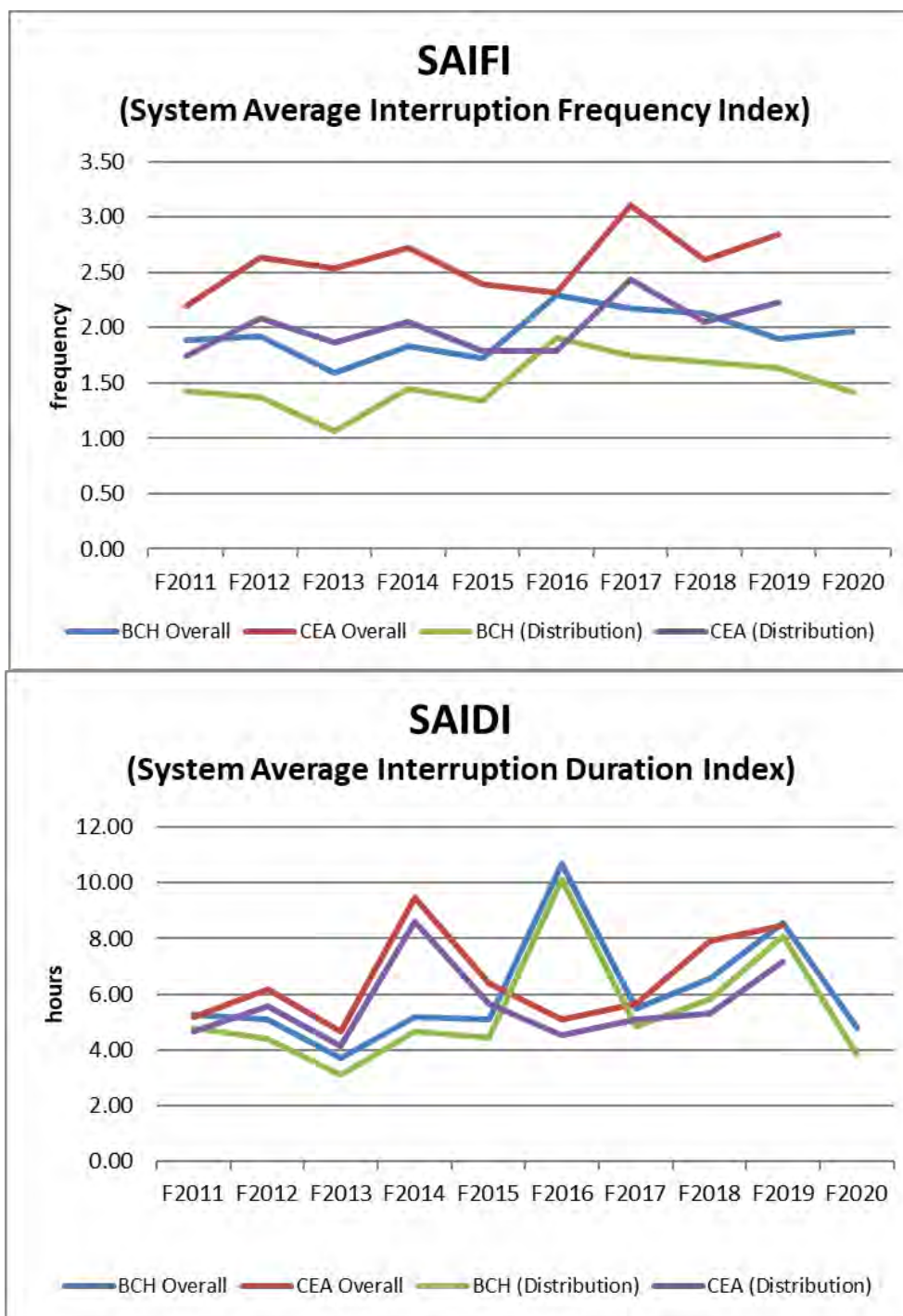
Note: CEA does not survey for CEMI-4 or IEEE 2.5 Beta.

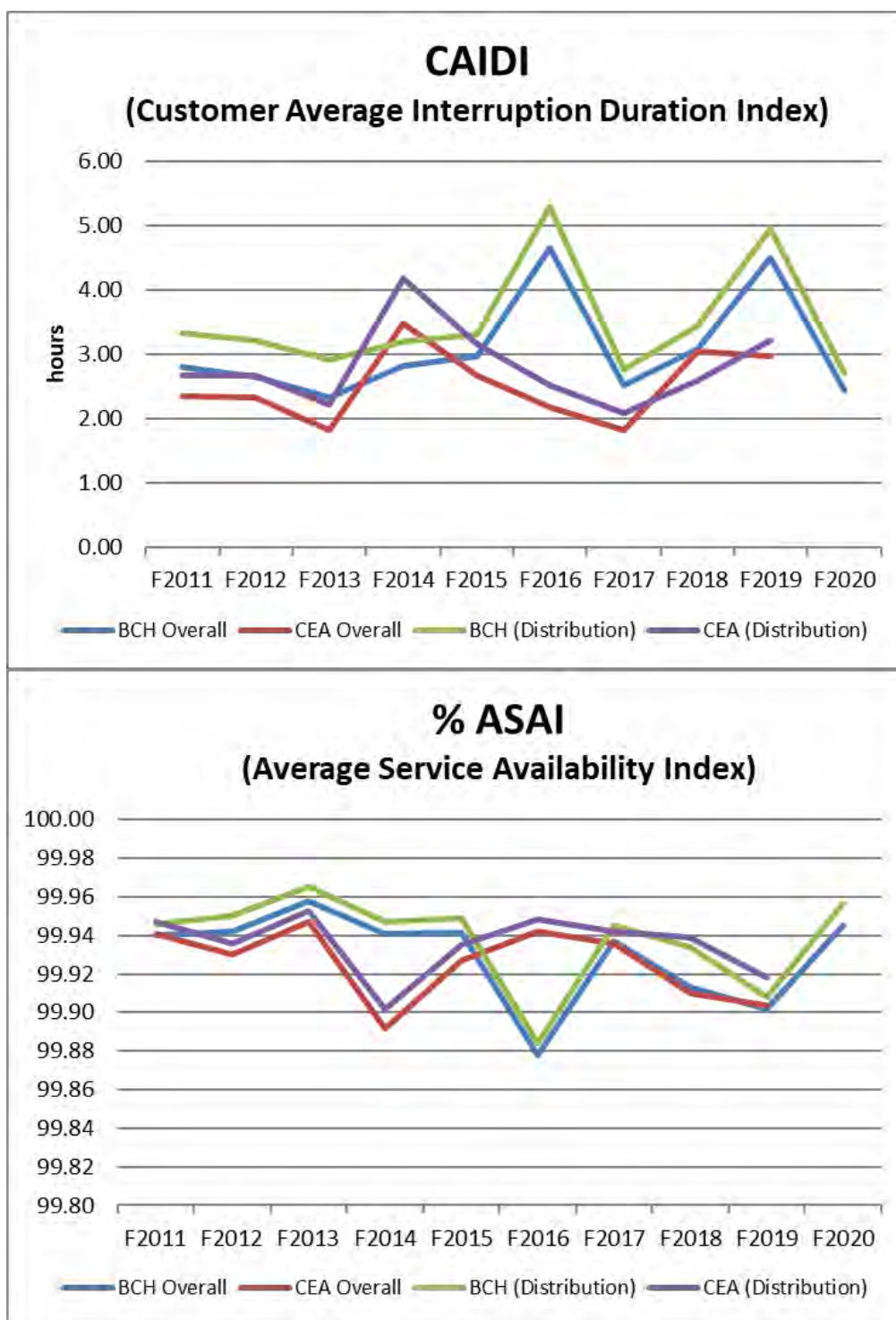
**Table 5 Reliability Indices – BC Hydro (Transmission)
 and CEA (Transmission) (Forced Data)
 (All-Event Indices, Not Normalized)**

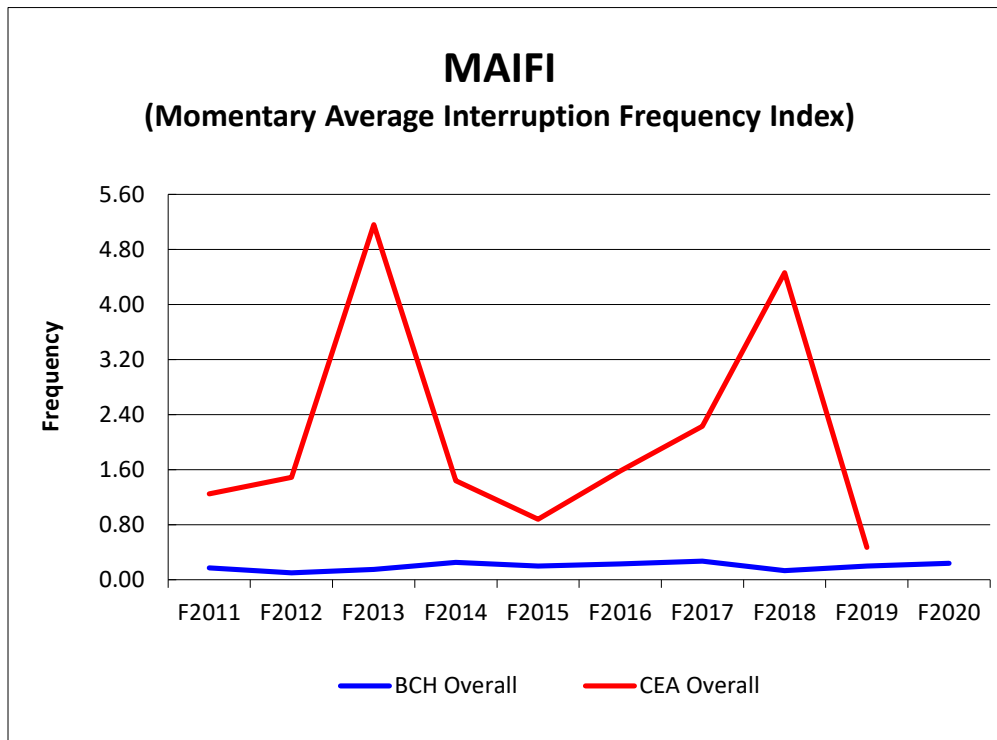
Year	BC Hydro (Transmission) (Forced)					CEA (Transmission) (Forced)				
	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI
F2011	0.38	0.71	1.30	11.31	1.83	0.54	0.64	1.39	13.22	2.16
F2012	0.43	0.86	1.55	19.39	1.81	0.84	0.81	1.73	23.35	2.13
F2013	0.56	0.74	1.64	17.16	2.19	0.84	0.90	4.48	51.18	4.98
F2014	0.74	0.87	2.57	25.18	3.01	0.86	0.83	2.59	27.07	3.11
F2015	0.83	0.74	2.11	26.41	2.86	0.72	0.83	2.56	19.24	3.10
F2016	0.79	0.63	2.46	27.77	3.90	0.85	0.74	2.15	15.60	2.90
F2017	0.63	0.61	2.52	33.61	4.13	0.70	0.75	1.93	22.33	2.58
F2018	0.30	0.69	2.50	30.13	3.62	0.55	0.77	2.24	20.02	2.90
F2019	0.57	0.34	0.92	7.61	2.71	0.65	1.06	3.48	33.87	3.27
F2020	0.42	0.64	1.73	19.05	2.72	n/a	n/a	n/a	n/a	n/a

Note: The CEA Bulk Electricity Study program reports only on forced outage results as not all the participating utilities report planned outages.

Distribution Graphs

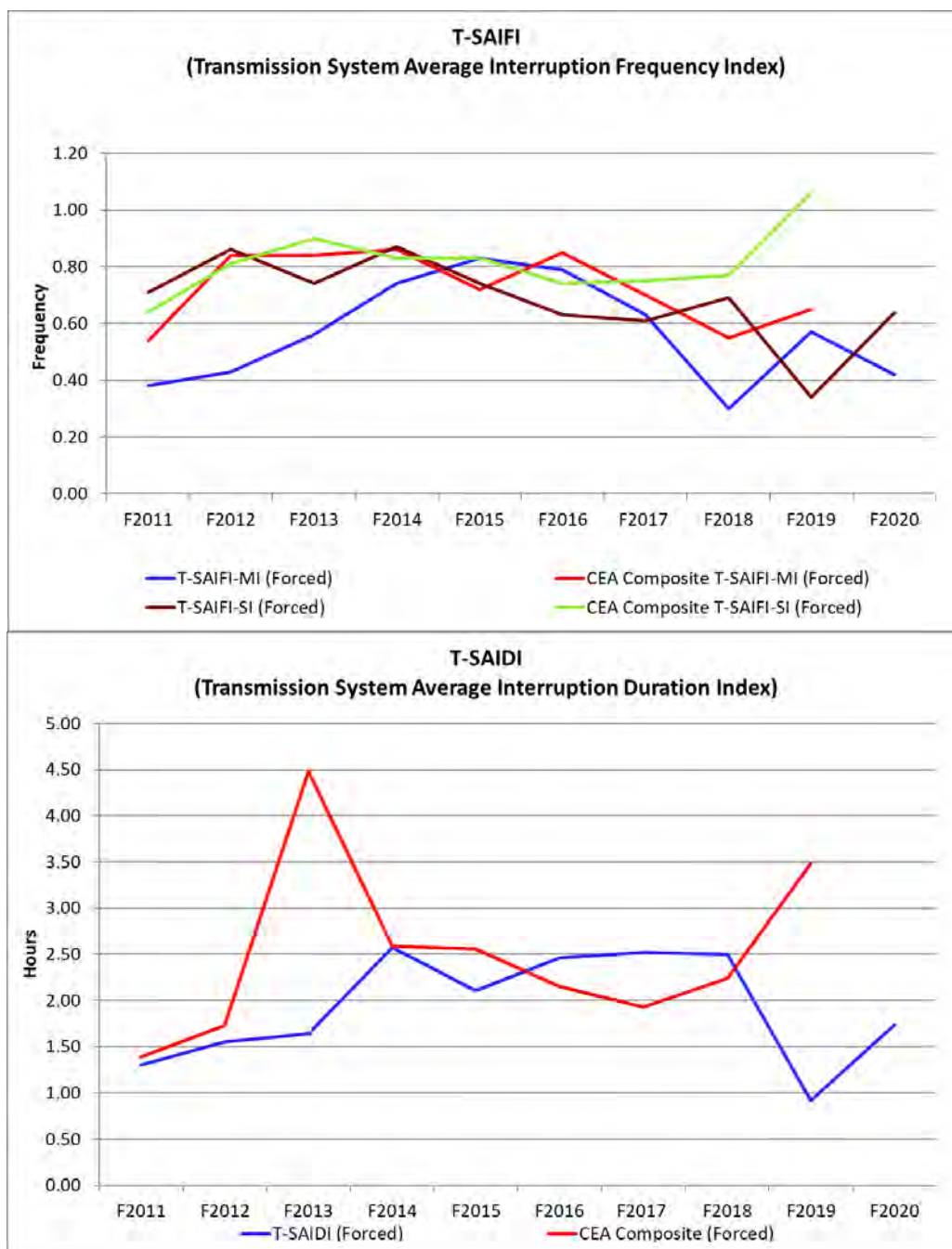


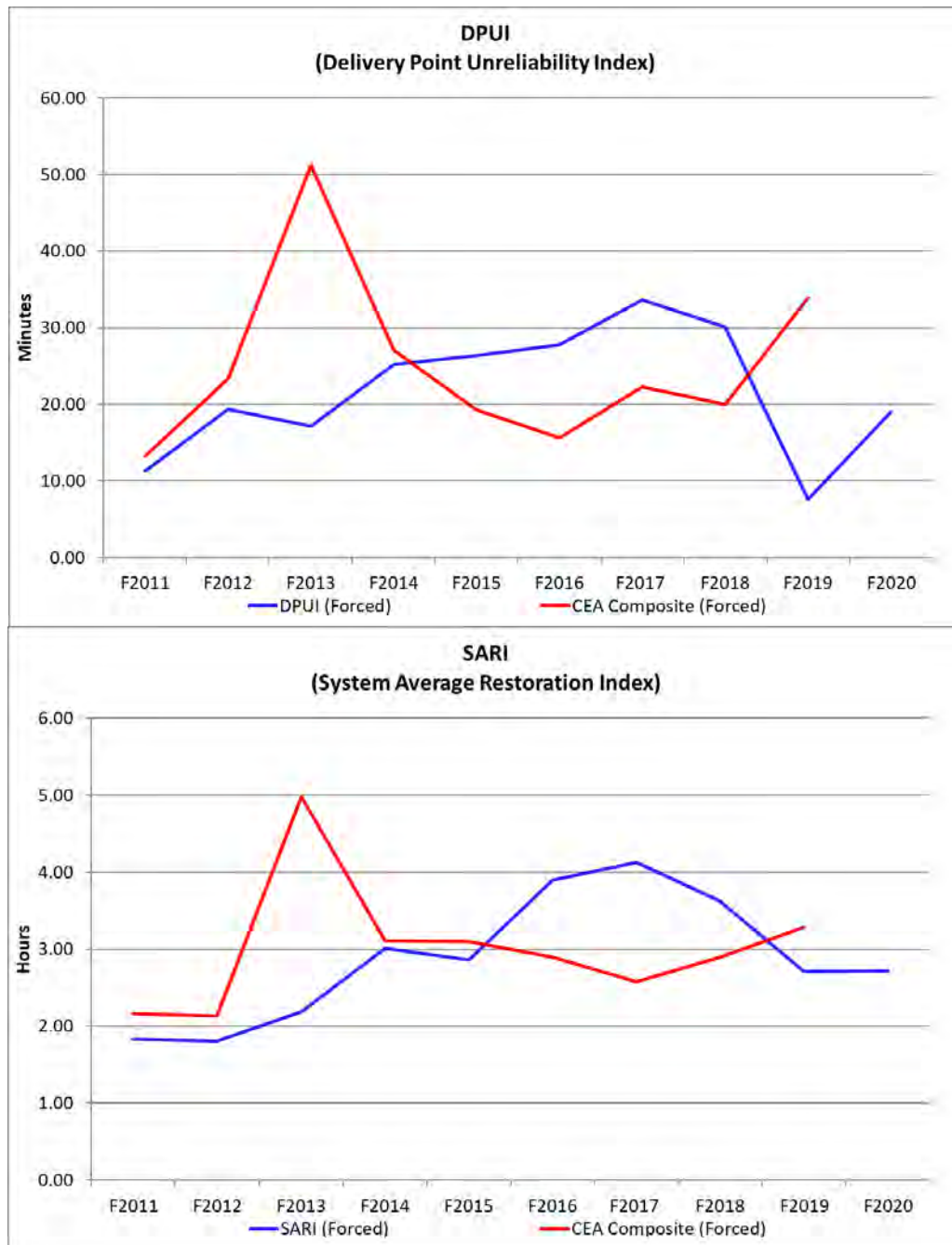




Note: The customer momentary interruptions and the resulting MAIFI may not apply to the utility's total customer population in the CEA comparison. Momentary outages are any interruptions on the feeders of less than one minute duration, caused by disturbance on the distribution, substation or transmission system.

Transmission Graphs





**F05/F06 Revenue Requirements Application
Annual Response to Directive 26 of BCUC Decision**

F2020 Annual Reporting of Reliability Indices

Attachment 2

Generation Reliability Indices

Appendix T
F2020 Annual Reporting of Reliability Indices
Attachment 2 - Generation Reliability Indices

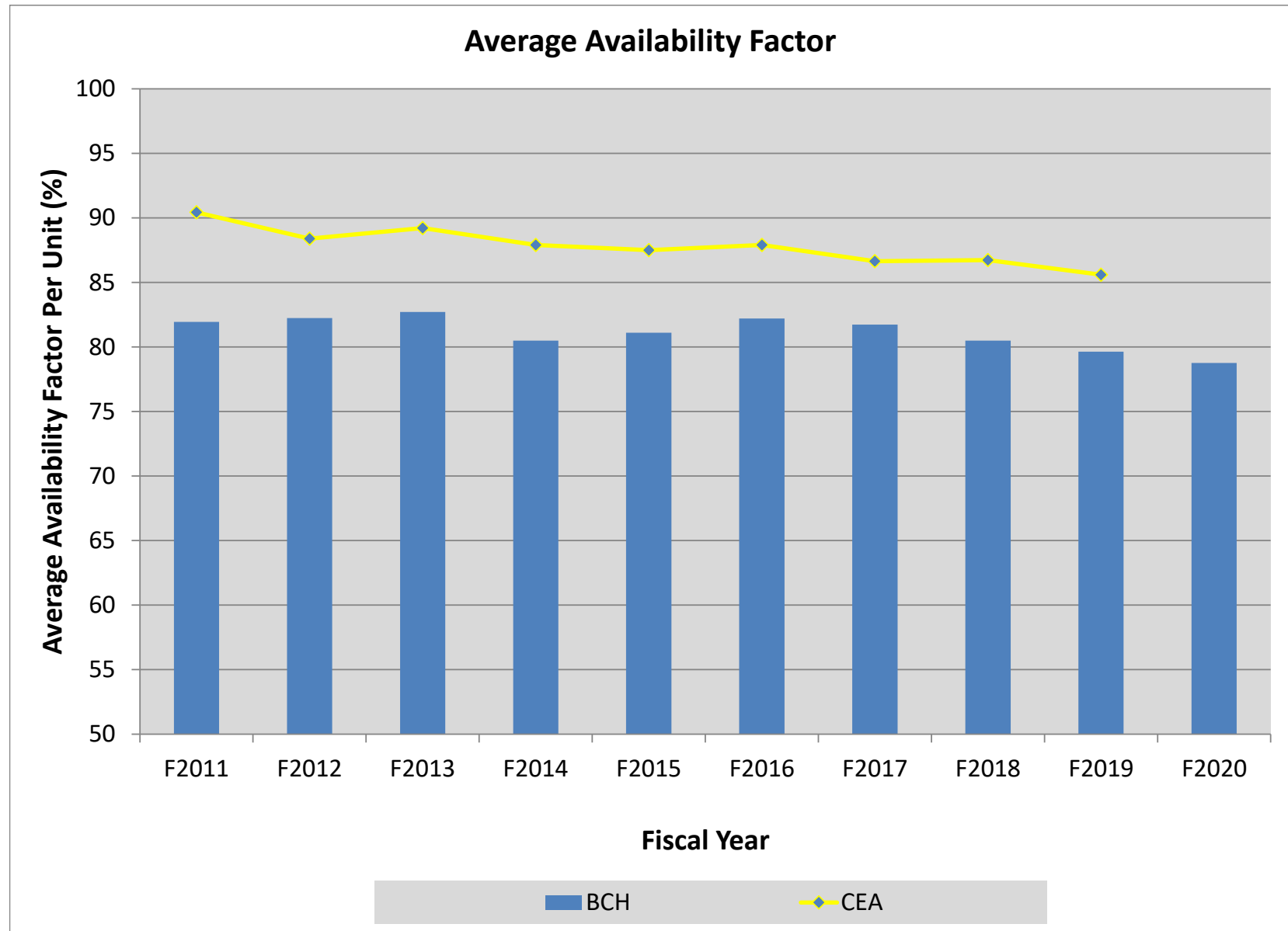
Fiscal Year	BC Hydro Hydroelectric Units					Calendar Year	CEA Hydroelectric Units				
	Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) ^{Note 1}	Average Forced Outage Factor (%) (Including starting failures) (Internal) ^{Note 1}	Failure Rate		Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) ^{Note 1}	Average Forced Outage Factor (%) (Including starting failures) (Internal) ^{Note 1&6}	Failure Rate
F2011	81.9	68.0	2.0	5.1	1.9	C2010	90.4	70.3	2.2	3.0	1.9
F2012	82.2	69.8	2.4	5.0	2.7	C2011	88.4	72.5	2.5	3.9	2.2
F2013	82.7	72.6	2.0	3.4	2.3	C2012	89.2	72.0	2.5	3.8	2.3
F2014 ^{Note 2}	80.5	64.7	2.5	4.7	2.7	C2013	87.9	74.0	2.4	3.9	2.1
F2015 ^{Note 3}	81.1	65.1	2.4	3.7	2.9	C2014	87.5	73.5	2.4	5.0	2.1
F2016 ^{Note 3}	82.2	65.9	2.0	4.1	2.4	C2015	87.9	70.4	3.2	4.7	2.1
F2017 ^{Note 3}	81.7	67.6	1.8	4.4	1.9	C2016	86.7	71.7	3.1	4.8	1.9
F2018 ^{Note 3}	80.5	65.5	1.7	2.6	2.0	C2017	86.7	73.0	3.3	4.9	2.2
F2019 ^{Note 3}	79.6	61.9	2.0	2.8	2.3	C2018	85.6	67.8	3.7	5.0	2.1
F2020 ^{Note 4}	78.8	59.1	2.0	4.3	2.3	C2019	n/a	n/a	n/a	n/a	n/a

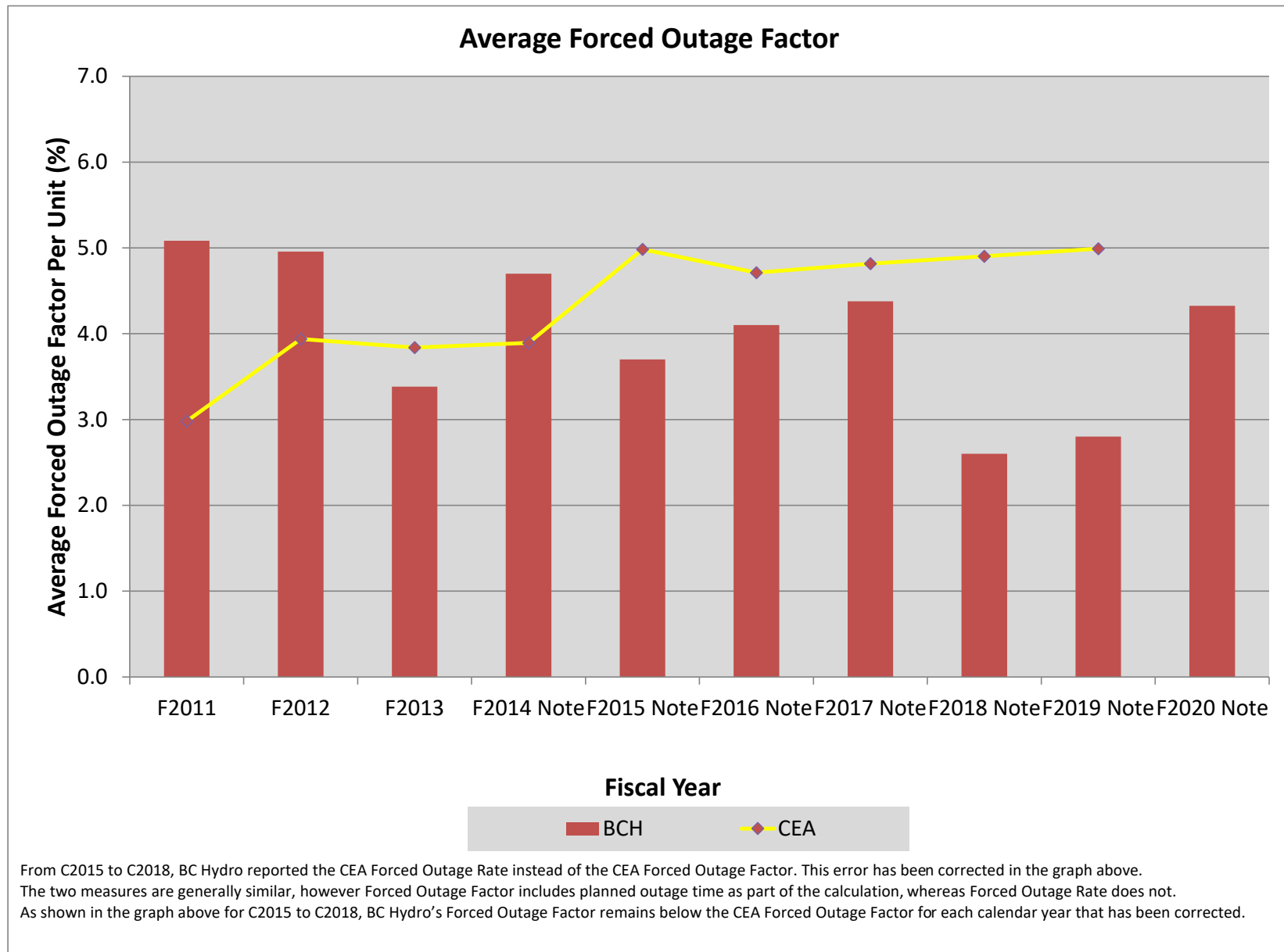
Definitions

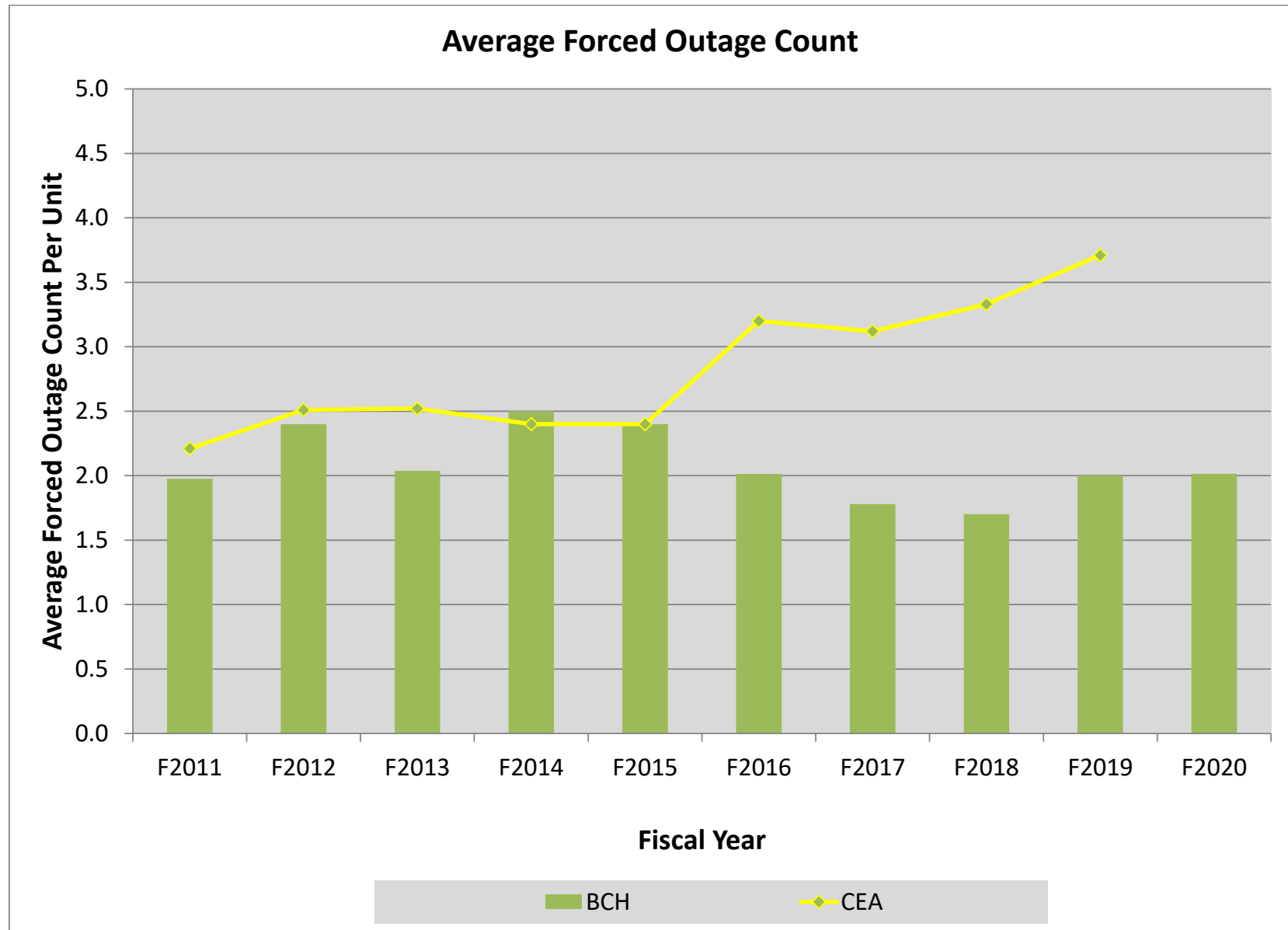
Availability Factor	= Operating Time + Available-But-Not-Operating Time / In Commercial Service Time ^{Note 5}
Forced Outage Count	= Average Number of Forced Outages / Unit / Year (including Starting Failures)(Internal)
Forced Outage Factor	= Forced Outage Time (including Starting Failures)(Internal) / Total Forced Outage Time + Total Operating Time + Total Planned Outage Time
Failure Rate	= Forced Outage Count (excluding Starting Failures)(Internal) / Operating Time X In Commercial Service Time ^{Note 5}
Forced Outage Rate	= Forced Outage Time (including Starting Failures)(Internal) / Total Forced Outage Time + Total Operating Time

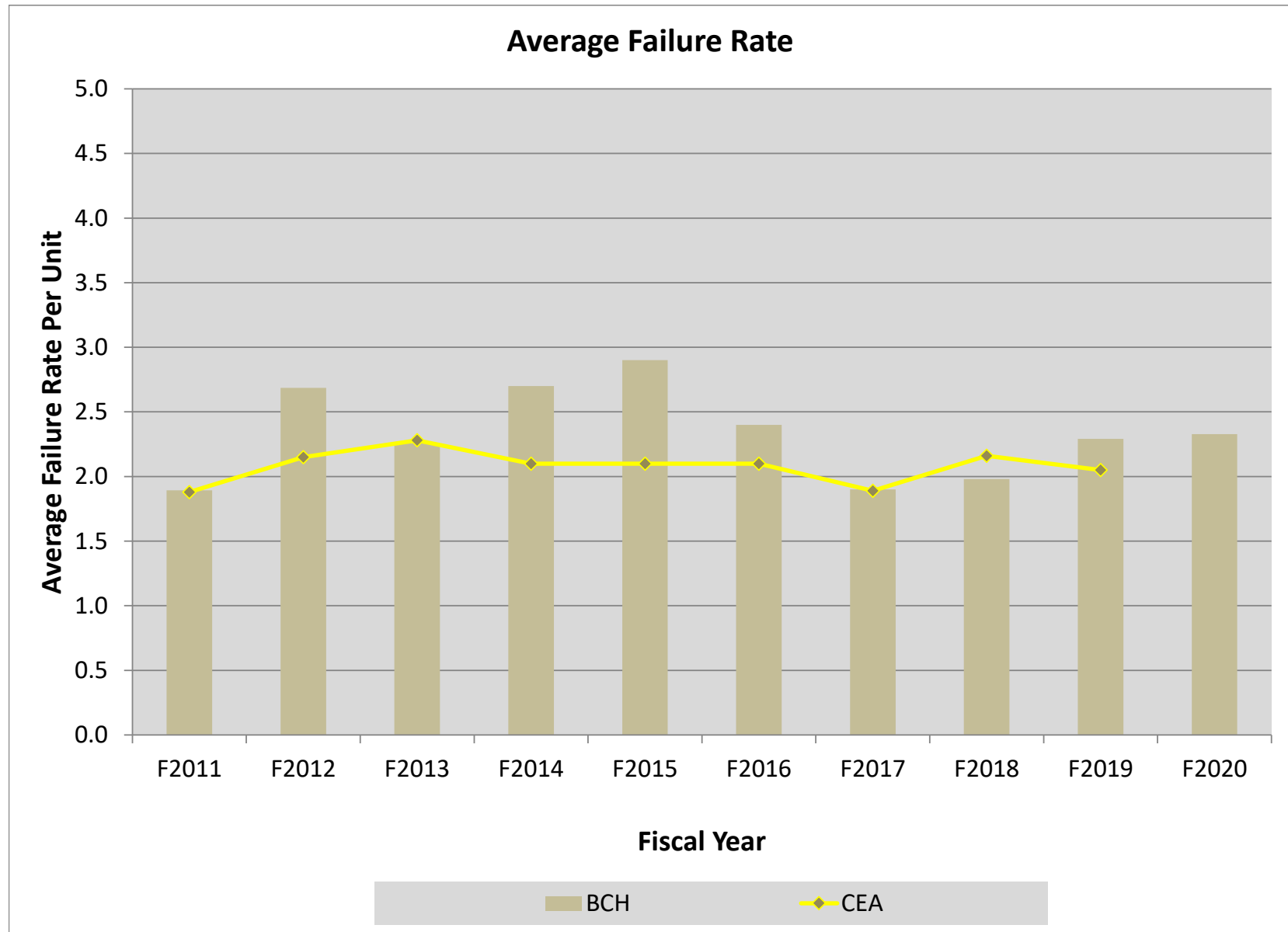
Notes

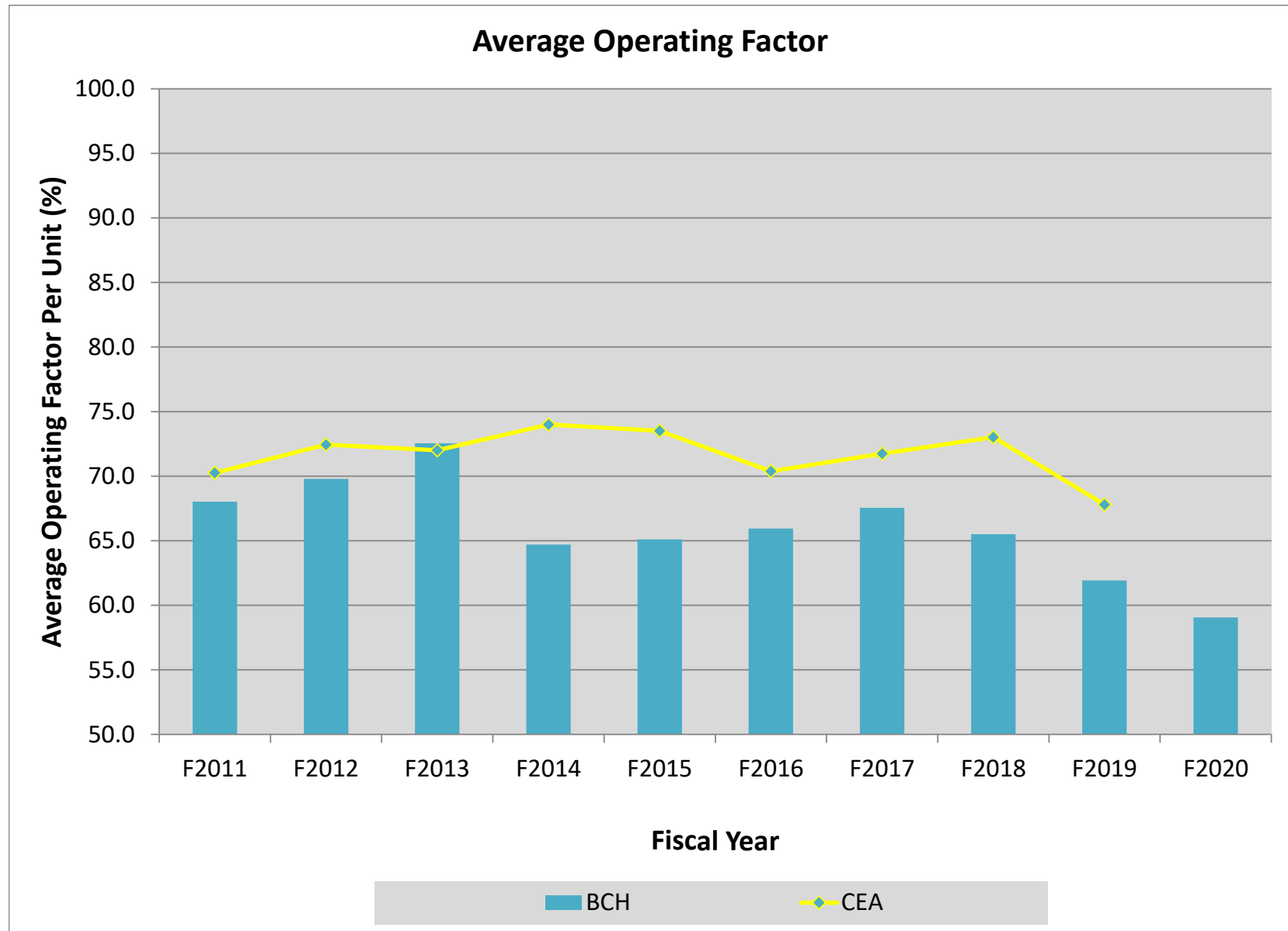
1. Outages with causes that were external to Generation, such as Transmission System forced outages, are excluded from this measure.
2. Data excludes ALU Unit 1 and SHU Unit 1, which have been forced out of service for an extended period.
3. Data excludes ALU Unit 1, SHU Unit 1 and ELK Units 1 and 2 which have been forced out of service for an extended period.
4. Data excludes ALU Unit 1, SHU Unit 1, ELK Units 1 and 2 and SPN Unit 1,2 and 3 which have been forced out of service for an extended period.
5. In Commercial Service Time represents the number of hours in the measurement period that the unit(s) were considered part of the active fleet.
6. From C2015 to C2018, BC Hydro reported the CEA Forced Outage Rate instead of the CEA Forced Outage Factor. This error has been corrected in the table above. The two measures are generally similar, however Forced Outage Factor includes planned outage time as part of the calculation, whereas Forced Outage Rate does not. As shown in the table above for C2015 to C2018, BC Hydro's Forced Outage Factor remains below the CEA Forced Outage Factor for each calendar year that has been corrected.











BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix U Description of Regulatory Accounts

This Appendix provides a verbatim copy of Chapter 7, sections 7.5, 7.7 and 7.8 from of the Previous Application for reference. Other sections have been removed and are denoted with ellipses.

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7.5 Types of Regulatory Accounts and Amortization Periods

The five types of regulatory accounts used by BC Hydro are consistent with the BCUC Regulatory Account Filing Checklist.³²¹ The five types of accounts are described below, including a discussion of the relevant considerations when determining the appropriate recovery mechanisms to ensure that the balances in the accounts are recovered over the appropriate time period.

7.5.1 Variance Accounts

Regulatory accounts may be used to capture variances between forecast costs or revenues and actual costs or revenues. For BC Hydro, this includes variances between forecast and actual costs due to non-controllable factors such as water inflow levels, interest rates, discount rates, and market prices of energy, which are difficult to forecast. These types of variances are captured in BC Hydro's cash and non-cash variance accounts, which are discussed below.

BC Hydro believes that it should generally assume financial responsibility for controllable risks and create variance accounts for non-controllable risks. In the Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, BC Hydro proposed the following criteria to assess whether a risk is controllable or non-controllable:³²²

³²¹ https://www.bcuc.com/Documents/Guidelines/2017/05-03-2017_RegulatoryAccountFilingChecklist.pdf. Specifically, when requesting approval for a new regulatory account, the BCUC Regulatory Account Filing Checklist requires that regulated entities classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other and to identify if the regulatory account is a cash or non-cash account.

³²² BC Hydro Fiscal 2005 - Fiscal 2006 Revenue Requirement Application Argument, page 70.

1. BC Hydro's ability to directly or indirectly influence the cost category;
2. The volatility of the cost category;
3. The predictability of the cost category;
4. The materiality of the cost category to the revenue requirement; and
5. The frequency of major exceptions within the cost category.

In its Decision on the Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, the BCUC accepted BC Hydro's proposed criteria but concluded that risk/reward considerations were also a relevant consideration.³²³

BC Hydro is not proposing any changes in this application to the criteria used to assess whether a risk is controllable or non-controllable.

BC Hydro's Cost of Energy Variance Accounts (the Heritage Deferral Account, the Non-Heritage Deferral Account and Trade Income Deferral Account) are examples of variance accounts that defer, for recovery or refund in a future period, differences between forecast and actual costs or revenues. The balances in these accounts are currently recovered through the DARR, which is discussed further in section [7.5.6](#).

BC Hydro also has cash variance accounts that capture the difference between forecast and actual costs for non-energy related costs that BC Hydro considers to be non-controllable. Examples include the Storm Restoration Costs and the Total Finance Charges regulatory accounts. Amounts transferred to cash variance accounts in a test period are generally recovered over the next test period. This approach is appropriate as these accounts represent costs that provide immediate, rather than long-term benefits.

Lastly, BC Hydro has non-cash variance accounts that capture the differences between forecast and actual non-controllable costs, which are non-cash in nature,

³²³ BC Hydro Fiscal 2005 to Fiscal 2006 Revenue Requirement Application Decision, pages 29 to 30.

for recovery from or refund to ratepayers in a future period. BC Hydro currently has four non-cash variance accounts: the Foreign Exchange Gains and Losses, the Non-Current Pension Costs, the PEB Current Pension Costs, and the Debt Management regulatory accounts. The recovery period for these variance accounts match the underlying attribute. For example, the Foreign Exchange Gains and Losses Regulatory Account is amortized on a straight-line pool basis over the weighted average life of the related debt and the Non-Current Pension Costs Regulatory Account is amortized over the average remaining service life of employees.

7.5.2 Benefit Matching Accounts

Regulatory accounts are often used to reflect timing differences between when a utility spends money to provide a service or acquire an asset, and when that expenditure provides benefits to ratepayers. The benefit of a particular service or asset may accrue to ratepayers over a long period of time. Regulatory accounts can be used to match the benefit with the cost, thereby supporting intergenerational equity between current and future ratepayers. The amortization period for this type of account will vary depending on the period of time that the benefit of a particular service or asset accrues to ratepayers. The use of this type of regulatory account means that BC Hydro's current customers are not required to pay for the full cost of an asset or service that will provide benefits to customers in the future.

The DSM Regulatory Account is an example of this type of account. Through DSM measures, BC Hydro spends money in current years to reduce the amount of electricity that customers would otherwise use in current and future periods. This results in lower energy costs and delayed or reduced infrastructure costs. The benefits of reduced costs from these DSM measures accrue to future customers. Therefore, the costs of DSM measures are matched to the benefits realized by future customers. DSM costs are deferred and amortized over 15 years, which

reflects the average measure life of DSM measures. Further information is provided in Chapter 10, section 10.5.6.

The Site C Regulatory Account is another example of this type of regulatory account. This account defers project investigation costs related to the Site C Project to future years. The Site C Project has a long development period before it will be placed into service and provide benefits to customers. If these project investigation costs had been expensed as incurred, it would have created unfair rate impacts on current ratepayers, prior to the benefits of the project being provided.

7.5.3 Non-Cash Provisions

Non-cash provisions are regulatory accounts set up in response to loss provision liabilities required under IFRS. These provisions are not recovered in rates until actual cash expenditures are made against the provision. At that time, the provision is drawn down by the amount of the expenditure and a corresponding amount is transferred to the matching regulatory account. This amount is then amortized into rates based on the approved amortization method. The provision regulatory accounts remain in place until the loss provision liability is no longer required under IFRS. These accounts are regulatory assets which, subject to BCUC approval, preserve BC Hydro's ability to collect, in rates, any actual amounts paid in respect of these provisions. BC Hydro currently has three non-cash provision regulatory accounts: the First Nations Provisions, the Environmental Provisions, and the Arrow Water Systems Provision regulatory accounts.

7.5.4 Rate Smoothing Accounts

Concerns about rate impacts can lead to the establishment of a regulatory account to smooth required rate increases over a period of time or to smooth the rate impact of a large, one-time expenditure. The recovery period for this type of account would be determined by the amount and nature of the expenditure, as well as other rate increase pressures that may exist at the time.

Pursuant to Direction No. 7, the BCUC had approved for use, starting in fiscal 2015, a Rate Smoothing Regulatory Account to defer portions of BC Hydro's allowed revenue requirement for recovery in rates in future fiscal years. As part of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of \$1.044 billion, resulting in a reduction to BC Hydro's retained earnings and a forecast net loss for BC Hydro in fiscal 2019. This means that the cost of the write-off is borne by the Government of B.C. as BC Hydro's shareholder, and not by ratepayers. As a result, there is a zero balance in the Rate Smoothing Regulatory Account at the beginning of the test period. BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period and is requesting BCUC approval to close the existing Rate Smoothing Regulatory Account.

7.5.5 IFRS Transition Accounts

A change in the accounting standards applicable to BC Hydro may create non-controllable financial impacts, requiring a regulatory account to protect customers from sudden and significant rate increases.

In fiscal 2013, BC Hydro transitioned to the Prescribed Standards directed by the Government of B.C.'s Treasury Board. The Prescribed Standards were based on the principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* with one modification. This change impacted the method of accounting for capital overheads. It also required BC Hydro to recognize, on its balance sheet, all unamortized actuarial gains and losses on its pension and other post-employment benefit plans. To recover the financial impact of these changes from customers over a reasonable time period, BC Hydro proposed the establishment of the IFRS Transition regulatory accounts. If BC Hydro had recognized the impact of the transition to IFRS in its rates at the time of the

1 transition, the rate impact for customers in the year of transition, would have been
2 significant.

3 The recovery periods for the IFRS Transition Accounts are 20 years for the
4 IFRS Pension Regulatory Account and 40 years for the IFRS Property, Plant and
5 Equipment Regulatory Account. These recovery periods mean that the accounts
6 recover the transition costs of pension and capital assets over the same period of
7 time as if the IFRS rules had not come into place as part of the Prescribed
8 Standards.

9 **7.5.6 Summary of Recovery Mechanisms**

10 [Table 7-4](#) below provides a summary of the rationale to determine the appropriate
11 recovery mechanisms for BC Hydro's regulatory accounts.

Table 7-4 Summary of Rationale for Regulatory Account Recovery Mechanisms

Type of Regulatory Account	Rationale for Recovery Mechanism
Variance Accounts:	
Cost of Energy Variance Accounts	The Deferral Account Rate Rider mechanism minimizes intergenerational inequity by being responsive to the changing net balance in the cost of energy variance accounts, while maintaining rate stability for customers to the extent practicable. BC Hydro is proposing to reduce the Deferral Account Rate Rider from 5 per cent to 0 per cent on April 1, 2019 and to refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts over the fiscal 2020 to fiscal 2021 test period.
Other Cash Variance Accounts	To minimize intergenerational inequity, cash variance accounts should be recovered in the subsequent test period.
Non-Cash Variance Accounts	Non-cash variances should be recovered over the remaining period of the associated asset or liability (e.g., estimated average remaining service life of employees or remaining term of debt issuances).
Benefit Matching Accounts	To achieve intergenerational equity, the recovery period should match the future benefit period of the expenditure.
Non-Cash Provisions	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account.
Rate Smoothing Accounts	Recovery mechanisms can vary based on the purpose of the rate smoothing account. For example, if the purpose of a rate smoothing account is to smooth rates over a specific test period only, the account should be recovered over the related test period. BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.
IFRS Transition Accounts	To smooth the impact of changes in accounting standards, the balances in these accounts should be recovered on the same basis as they would have been recovered under the previous accounting rules.

BC Hydro has BCUC approved recovery mechanisms to collect, in rates, the balances in almost all of its regulatory accounts. The following three regulatory accounts do not have approved recovery mechanisms, as they are not yet required:

- 1 1. Mining Customer Payment Plan Regulatory Account – BC Hydro will request a
2 recovery mechanism, if necessary, upon completion of the five year program,
3 which commenced in March 2016. This account currently has a zero balance;
- 4 2. Customer Crisis Fund Regulatory Account – BC Hydro will request a recovery
5 mechanism upon completion of the three year pilot program which commenced
6 in May 2018; and
- 7 3. Site C Regulatory Account – BC Hydro will request a recovery mechanism for
8 this account in a future application, as the project is not yet in-service.

...

22 **7.7 BC Hydro's Proposed Changes to Regulatory** 23 **Accounts are Limited**

24 BC Hydro is requesting approval of seven changes related to existing regulatory
25 accounts and to close two existing regulatory accounts. BC Hydro is not requesting
26 approval of any new regulatory accounts in this application.

Specifically, BC Hydro requests BCUC approval to:

- Reduce the DARR from 5 per cent to 0 per cent on April 1, 2019;
- Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period. This would result in a net credit to the benefit of ratepayers of \$329.1 million being amortized into rates during the test period;
- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
- Defer any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account. This will ensure that BC Hydro recovers its costs with respect to the Biomass Energy Program;³²⁴
- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;
- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs;
- Remove the reference to the “Prescribed Standards” from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully

³²⁴ The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.

adopted IFRS. This will allow BC Hydro to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized;

- Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time; and
- Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.

The sections below provide the rationale for each proposed change to the regulatory accounts. To provide context for to these requests, the sections below include a description of the account, the history of the account and the existing or proposed recovery mechanism or period for the recovery of the account balance.

7.7.1 Cost of Energy Variance Accounts

BC Hydro has three Cost of Energy Variance Accounts that capture the differences between forecast and actual revenues and energy costs: the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account.

The Heritage Deferral Account and Trade Income Deferral Account were created pursuant to Heritage Special Direction No. HC2 and BCUC Order No. G-96-04. Special Direction No. HC2 was repealed in March 2014 and the Heritage Deferral Account and the Trade Income Deferral Account were continued on an ongoing basis through Direction No. 7 and BCUC Order No. G-48-14.

By Order No. G-96-04, the BCUC also approved the establishment of the Non-Heritage Deferral Account and approved the specific cost components eligible for deferral to the Heritage Deferral Account and to the Non-Heritage Deferral Account. Through subsequent Orders, the scope of the Non-Heritage Deferral

Account has been expanded.³²⁵ Notably, by Order No. G-16-09, the BCUC authorized BC Hydro to defer to the Non-Heritage Deferral Account, the variances between forecast and actual cost of energy arising from differences in forecast and actual domestic customer load in fiscal 2009 and fiscal 2010. This was continued through the Fiscal 2011 Negotiated Settlement Agreement and by Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application. Direction No. 7 required the BCUC to allow these variances to be deferred to the Non-Heritage Deferral Account on an ongoing basis. Direction No. 7 also required the BCUC to allow BC Hydro to defer costs associated with the decommissioning of portions of Burrard Thermal not required for transmission support services, to the Non-Heritage Deferral Account.

The purpose of the three Cost of Energy Variance Accounts is to defer the differences between forecast and actual revenues and energy costs for recovery or refund to ratepayers in future periods. These differences are non-controllable and can be positive or negative. The variances captured by the Cost of Energy Variance Accounts can be summarized as follows:

- The Heritage Deferral Account captures variances between the forecast and actual cost of Heritage Energy, Market Electricity Purchases, Surplus Sales and Domestic Transmission costs related to Surplus Sales as described in Chapter 4, sections 4.2.2 and 4.2.4. In addition, the Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No. G-96-04, which includes Skagit Valley Treaty revenues.

³²⁵ BCUC Order No. G-16-11 approved the deferral of variances between forecast and actual transmission service revenue and non-capital emergency transmission maintenance expenditures over \$1 million to the Non-Heritage Deferral Account.
BCUC Order No. G-68-17 approved the deferral of variances between forecast and actual Northwest Transmission Line Supplemental Charge revenues to the Non-Heritage Deferral Account.
BCUC Order No. G-130-18 approved the deferral of the fiscal 2019 Lease revenues arising from the Waneta 2017 Transaction and the revenue associated with capital expenditures made by Teck with respect to Teck's two-third interest in Waneta during the Lease Term to the Non-Heritage Deferral Account. The Order also approved that the variance between forecast and actual water rentals in a given year arising from the Waneta 2017 transaction be excluded from the water rental variances that are currently deferred to the Non-Heritage Deferral Account during the Lease Term.

- The Non-Heritage Deferral Account captures variances between the forecast and actual cost of Non-Heritage Energy which includes IPPs and Long-Term Commitments, and Net Purchases (Sales) from Powerex as described in Chapter 4, sections 4.2.3 and 4.2.4. In addition, the Non-Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No G-96-04, variances between forecast and actual domestic customer load (referred to as the Domestic Revenue Variance), and subsequent Orders as noted above.
- The Trade Income Deferral Account captures variances between the forecast and actual Trade Income as described in Chapter 8, section 8.9.

7.7.1.1 Recovery Mechanism

BC Hydro believes that it continues to be appropriate to defer cost and revenue variances to the Cost of Energy Variance Accounts, consistent with past practice and existing orders. These variances are non-controllable and the deferral of variances ensures that BC Hydro's customers pay the actual costs.

The fiscal 2019 forecast closing balance in the Cost of Energy Variance Accounts is a net credit balance (i.e., amount owing to ratepayers) of \$293 million, in part due to a one-time accounting adjustment of \$319 million as a result of the adoption of a new IFRS revenue standard in fiscal 2019. The application of IFRS 15, *Revenue from Contracts with Customers*, impacted the recognition of revenues under the Skagit River Agreement, resulting in a retroactive decrease in unearned revenues and a corresponding adjustment to the Heritage Deferral Account to the benefit of ratepayers.³²⁶ Further information is provided in Chapter 8, section 8.13.2.

BC Hydro recovers the balances in the Cost of Energy Variance Accounts using the DARR. Direction No. 7 set the DARR for fiscal 2015 and future fiscal years at

³²⁶ BCUC Order No. G-96-04 approved the deferral of variances between forecast and actual Skagit Valley Treaty revenues to the Heritage Deferral Account. Accordingly, the adjustment was deferred to the Heritage Deferral Account, to the benefit of ratepayers.

1 5 per cent. However, because Direction No. 7 was repealed and because BC Hydro
2 is forecasting a net credit balance in the accounts for fiscal 2019, BC Hydro is
3 proposing to amortize this balance over the test period. BC Hydro believes that it is
4 appropriate to refund this net credit balance to ratepayers over the fiscal 2020 to
5 fiscal 2021 test period. This would allow ratepayers to realize the benefit of this net
6 credit balance more immediately than if the credit were to be refunded to ratepayers
7 through the DARR.

8 As these are variance accounts, BC Hydro would not normally forecast additions to
9 the Cost of Energy Variance Accounts. However, over the test period, BC Hydro is
10 forecasting additions to the Non-Heritage Deferral Account for a one-time credit of
11 \$18.0 million in fiscal 2020 arising from a transition adjustment related to the
12 adoption of a new IFRS 16, *Leases* standard as described in Chapter 8,
13 section 8.13.3. In addition, BC Hydro is forecasting additions of \$3.1 million in
14 fiscal 2020 and \$3.5 million in fiscal 2021 related to revenue that BC Hydro is
15 required to recognize for capital expenditures made by Teck with respect to Teck's
16 2/3 interest in Waneta over the lease period.³²⁷

17 Therefore, in this application, BC Hydro is requesting BCUC approval to:

- 18 • Reduce the Deferral Account Rate Rider from 5 per cent to 0 per cent on
19 April 1, 2019; and
- 20 • Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020
21 and fiscal 2021 net additions and net interest applied to the Cost of Energy
22 Variance Accounts, over the fiscal 2020 to fiscal 2021 test period.

23 This would result in a net credit to the benefit of ratepayers of \$329.1 million being
24 amortized into rates during the test period.

³²⁷ BCUC Order No. G-130-18 approved the deferral of the revenue associated with capital expenditures made by Teck with respect to Teck's two-third interest in Waneta during the Lease Term to the Non-Heritage Deferral Account.

1 Based on BC Hydro's proposed approach, the forecast balance in each of the Cost
2 of Energy Variance Accounts will be zero at the end of fiscal 2021.

3 BC Hydro expects to propose to return to the DARR table mechanism approved by
4 the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in
5 the subsequent test period starting in fiscal 2022.

6 **7.7.1.2 IFRS 16, Leases (Energy Purchase Agreements)**

7 As discussed in Chapter 8, section 8.13.3 of the application, BC Hydro will adopt a
8 new IFRS 16, *Leases* standard, which will become effective for BC Hydro on
9 April 1, 2019. BC Hydro has made estimates based on its preliminary assessment
10 regarding the impacts of IFRS 16 and has included them in this Application.
11 However, the actual impacts of the new standard may vary from these estimates as
12 BC Hydro completes its assessment, including as a result of clarifications and
13 interpretive guidance that may be developed by the International Accounting
14 Standards Board, accounting firms and industry groups to assist in the
15 implementation of the new standard. BC Hydro anticipates that material variances
16 are possible when we complete our assessment of EPAs, including the review by
17 our external auditors. As shown in Chapter 8, section 8.12.1, BC Hydro has deferred
18 positive variances related to EPA capital leases into the Non-Heritage Deferral
19 Account in order to provide the benefit to ratepayers, even though this was not
20 required under existing orders.

21 Therefore, in this application, BC Hydro requests BCUC approval to:

- 22 • Defer any variances related to the accounting for EPAs determined to be leases
23 under IFRS 16, which are not eligible for deferral treatment under existing
24 orders, to the Non-Heritage Deferral Account.

25 **7.7.1.3 Biomass Energy Program**

26 As discussed in Chapter 4, section 4.3.2, the Comprehensive Review included the
27 announcement of the Biomass Energy Program. The Government of B.C. indicated

1 that it intends to provide a direction to the BCUC with respect to the approval of the
2 program documentation and require the costs associated with the Biomass Energy
3 Program to be recovered from ratepayers.

4 BC Hydro may be required to account for some of the costs associated with the
5 Biomass Energy Program as amounts other than cost of energy (variances related
6 to which would generally be deferred to the Non-Heritage Deferral Account pursuant
7 to existing orders). Until contracts relating to the identified biomass projects are
8 completed, BC Hydro cannot have certainty on the amount of those costs or how to
9 appropriately account for them.

10 BC Hydro proposes that variances related to the Biomass Energy Program be
11 deferred to the Non-Heritage Deferral Account.

12 Therefore, in this application, BC Hydro requests BCUC approval to:

- 13 • Defer any variances between forecast and actual amounts related to the
14 Biomass Energy Program which are not eligible for deferral treatment under
15 existing orders, to the Non-Heritage Deferral Account. This will allow BC Hydro
16 to recover its costs with respect the Biomass Energy Program.³²⁸

17 **7.7.2 Dismantling Cost Regulatory Account**

18 By Order No. G-47-18 to the Previous Application, the BCUC approved the deferral
19 of variances between forecast and actual dismantling costs over the fiscal 2017 to
20 fiscal 2019 test period, the application of interest to the account, and the recovery of
21 the forecast account balance at the end of the test period over the next test period.
22 BC Hydro is proposing to continue the Dismantling Cost Regulatory Account on an
23 ongoing basis.

³²⁸ The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.

In its Decision, the BCUC stated that, in its view, the timing of dismantling activities is largely within BC Hydro's control but that the establishment of the account for the test period would allow BC Hydro to gain more experience with forecasting the timing of expenditures.³²⁹

BC Hydro is not in a better position now than it was over the last test period to forecast dismantling costs accurately. In BC Hydro's view, the nature of dismantling costs makes them difficult to forecast accurately. As shown in the table below, dismantling cost variances can be positive or negative and continue to be significant in recent years. More specifically, [Table 7-5](#) shows that variances have ranged from \$14.1 million below plan to \$31.7 million above plan (with a range between -41 per cent to +89 per cent of plan) since fiscal 2012.

**Table 7-5 Dismantling Cost Variances
Fiscal 2012 to Fiscal 2018 Actual and
Fiscal 2019 Forecast**

(\$ million)	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
	1	2	3	4	5	6	7	8
Actual ¹	20.2	16.4	32.2	22.4	24.2	42.4	67.5	44.5
RRA Plan	34.3	20.9	21.0	24.6	31.2	39.5	35.7	30.6
Variance from Plan (Actual - RRA Plan)	(14.1)	(4.5)	11.2	(2.2)	(7.0)	2.9	31.7	13.9
% Variance from Plan	-41%	-21%	53%	-9%	-22%	7%	89%	45%

¹F2019 is a forecast amount

Actual dismantling costs can vary significantly from planned amounts for a number of reasons.

The rationale for the Dismantling Cost Regulatory Account is the same as the rationale for the Amortization of Capital Additions Regulatory Account, which captures variances between forecast and actual amortization of capital additions. Dismantling costs are largely driven by BC Hydro's capital plan and are impacted by capital project schedules. Similar to capital projects, dismantling projects may be forecast

³²⁹ BCUC Decision and Order No. G-47-18, BC Hydro Previous Application (March 1, 2018), pages 62 to 63.

1 well in advance of the actual work taking place. Project estimates may be from an
2 earlier stage of the project lifecycle and will have different degrees of accuracy
3 depending on the phase of the project.

4 In addition, actual dismantling costs are expected to differ from forecast amounts
5 due to differences in timing and scope. Dismantling work occurs based on capital
6 project schedules, which can change and cause material shifts in the timing of
7 dismantling expenditures. Any delays or advancements to capital project schedules
8 could result in these expenditures being incurred earlier or later than planned. In
9 addition, as additional work requirements may be determined as activities progress,
10 the full scope and cost of dismantling activities may not be known until the work is
11 underway.

12 Further, emergency dismantling of assets is sometimes required and unplanned
13 dismantling may be required for projects that were not included in the dismantling
14 cost forecast in a given test period. For example, in fiscal 2018, BC Hydro
15 decommissioned the Salmon River Diversion, which was originally planned to be
16 upgraded, resulting in unplanned dismantling cost expenditures. By
17 Order No. G-96-17, the BCUC approved BC Hydro's request to decommission the
18 Salmon River Diversion and allowed the decommissioning costs to be transferred to
19 the Dismantling Costs Regulatory Account. This transfer meant that these
20 dismantling costs were appropriately recovered from ratepayers.

21 BC Hydro believes that it is appropriate to continue to defer, on an ongoing basis,
22 the variances between forecast and actual dismantling costs, for recovery over the
23 next test period. There are significant dismantling costs planned during the test
24 period in the amount of \$67 million in fiscal 2020 and \$43 million in fiscal 2021. In
25 the absence of the Dismantling Cost Regulatory Account, significant gains or losses
26 could accrue to ratepayers or the Government of B.C. as BC Hydro's shareholder.
27 Continued use of the account for the test period will mean that ratepayers pay the
28 actual costs of dismantling activities.

Therefore, in this application, BC Hydro is requesting BCUC approval to:

- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account;
- Continue to apply interest to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt;
- Effective starting in fiscal 2020, and on an ongoing basis, recover the forecast interest charged to the Dismantling Cost Regulatory Account each year from the account each year; and
- On an ongoing basis, recover the forecast account balance at the end of a test period over the next test period.

7.7.3 DSM Regulatory Account

By Order No. G-55-95, the BCUC directed the deferral and recovery of costs associated with DSM activities. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer these costs to the DSM Regulatory Account and to amortize the balance of the account into rates over 15 years, on an ongoing basis.

The Direction to the BCUC Respecting the Authority's TMP Program (Order in Council No. 404, issued on July 14, 2015) specified that BC Hydro be allowed to defer costs incurred related to the Thermo-Mechanical Pulp program, up to \$100 million, to the DSM Regulatory Account. BC Hydro's forecast costs related to the Thermo-Mechanical Pulp Program are discussed in Chapter 10.

The Direction to the BCUC Respecting Undertaking Costs (Order in Council No. 100, issued on March 1, 2017) specified that BC Hydro be allowed to defer low-carbon electrification expenditures, to the DSM Regulatory Account.

BC Hydro's forecast costs related to low carbon electrification are discussed in Chapter 10.

In this application, BC Hydro requests BCUC approval to:

- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs.

7.7.4 Site C Regulatory Account

By Order No. G-143-06, the BCUC approved the creation of a regulatory account related to Site C Project expenditures and approved deferral of project costs incurred in fiscal 2007 and fiscal 2008 to the account. The Fiscal 2009 to Fiscal 2010 Revenue Requirements Application Decision and Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement extended the deferral of project costs to the Site C Regulatory Account to the end of fiscal 2011. By Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirement Application, the BCUC authorized the deferral of all operating costs incurred related to the Site C Project in fiscal 2012 to fiscal 2014. By Order No. G-48-14, the BCUC authorized the deferral of all operating costs incurred in fiscal 2015 and fiscal 2016.

Following the final investment decision by the Government of B.C. to proceed with the Site C Project, BC Hydro commenced capitalization of costs related to the project starting in January 2015. While BC Hydro has commenced capitalization of costs, certain costs related to the project may not be eligible for capitalization under IFRS. For example, some legal costs are not eligible for capitalization under IFRS.

By Order No. G-47-18 to the Previous Application, the BCUC approved the deferral of any costs related to the Site C Project that are not able to be capitalized under the Prescribed Standards, to the Site C Regulatory Account.

As discussed in Chapter 8, section 8.13, BC Hydro has fully adopted IFRS, effective for its fiscal year ending March 31, 2019. As a result, the reference to the

1 “Prescribed Standards” should be removed from the scope of what may be deferred
2 to the Site C Regulatory Account. Consistent with the BCUC’s prior Orders, this
3 would allow BC Hydro to continue to defer to the Site C Regulatory Account any
4 costs related to the Site C Project that are not able to be capitalized.

5 As described in Chapter 8, section 8.13.4, as a result of the adoption of IFRS 14, the
6 amortization of the Debt Management Regulatory Account can no longer be
7 classified as finance charges and as such can no longer be included in the
8 calculation of BC Hydro’s interest during construction that is applied to capital
9 projects (i.e., capitalized).

10 For the test period, BC Hydro forecasts that the amount of interest during
11 construction attributable to the Site C Project that can no longer be capitalized is
12 \$2.0 million in fiscal 2020 and \$2.7 million in fiscal 2021. These are credit amounts
13 as the Debt Management Regulatory Account is currently in a credit balance. As
14 these amounts can no longer be capitalized under IFRS, they would be deferred to
15 the Site C Regulatory Account.

16 Therefore, in this application, BC Hydro is requesting BCUC approval to remove the
17 reference to the “Prescribed Standards” from the scope of what may be deferred to
18 the Site C Regulatory Account, as BC Hydro has fully adopted IFRS. This will allow
19 BC Hydro to continue to defer to the Site C Regulatory Account any costs related to
20 the Site C Project that are not able to be capitalized.

21 **7.7.5 Capital Project Investigation Costs Regulatory Account**

22 By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements
23 Application, the BCUC approved the establishment of a regulatory account for
24 capital project investigation costs. The Fiscal 2011 Revenue Requirement
25 Application Negotiated Settlement Agreement provided that additions to the Capital
26 Project Investigation Costs Regulatory Account would be discontinued at the end of
27 fiscal 2011, and that the closing fiscal 2011 balance would be amortized beginning in
28 fiscal 2012. BCUC Order No. G-77-12A approved the amortization of the fiscal 2011

1 closing balance over a 10 year period, commencing in fiscal 2012. Consistent with
2 BCUC Order No. G-77-12A, the balance in this account will be fully amortized into
3 rates by the end of fiscal 2021.

4 Therefore, in this application, BC Hydro is requesting BCUC approval to:

- 5 • Close the Capital Project Investigation Costs Regulatory Account at the end of
6 fiscal 2021 as its balance will be fully amortized into rates at that time.

7 **7.7.6 Rate Smoothing Regulatory Account**

8 In accordance with Direction No. 7, BCUC Order No. G-48-14 established the Rate
9 Smoothing Regulatory Account in fiscal 2015 to defer, for recovery in rates in future
10 fiscal years, those portions of the allowed revenue requirement in a particular
11 fiscal year that were not to be recovered in rates in that particular fiscal year.

12 Approved additions to this regulatory account from fiscal 2015 to fiscal 2019 total
13 \$1.136 billion. As a result of the Comprehensive Review, BC Hydro ceased using
14 the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019.

15 The balance of the Rate Smoothing Regulatory Account was written-off in
16 December 2018 in the amount of \$1.044 billion, resulting in a reduction to
17 BC Hydro's retained earnings and a forecast net loss for BC Hydro in fiscal 2019.
18 This means that the cost of the write-off is borne by the Government of B.C. as
19 BC Hydro's shareholder, and not by ratepayers. As a result, there is a zero balance
20 in the Rate Smoothing Regulatory Account at the beginning of the test period.

21 BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test
22 period.

23 Therefore, in this application, BC Hydro is requesting BCUC approval to:

- 24 • Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has
25 a zero balance and BC Hydro is not proposing to smooth rates over the
26 fiscal 2020 to fiscal 2021 test period.

7.8 BC Hydro is Not Seeking Changes to Most Regulatory Accounts

Consistent with prior applications, provided below is an overview of the history and recovery periods of the regulatory accounts for which BC Hydro is not seeking any changes.

7.8.1 Storm Restoration Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC approved the ongoing deferral of the difference between actual storm related restoration costs and the average of the actual storm restoration costs for the five most recent normal weather years. Fiscal 2014 through fiscal 2018 comprise the five most recent normal weather years and result in an average annual storm restoration cost of \$17.8 million. BC Hydro has included this amount for storm restoration costs in its fiscal 2020 and fiscal 2021 operating costs plan.

In recent years, BC Hydro has experienced more frequent storms and extreme weather resulting in higher storm-related expenditures, which has caused the five-year average to increase as shown in [Table 7-6](#) below.

Table 7-6 Storm Restoration Costs Fiscal 2014 to Fiscal 2018 Actual

(\$ million)	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2014-F2018 Average
	1	2	3	4	5	6
Storm Restoration Costs	4.6	12.9	23.5	25.3	22.9	17.8

By Order No. G-47-18 to the Previous Application, the BCUC approved that interest continue to be applied to the balance of this regulatory account and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

BC Hydro is not requesting any changes to this account in this application.

7.8.2 Amortization of Capital Additions Regulatory Account

By Order No. G-16-09, the BCUC directed BC Hydro to defer to a regulatory account any differences between forecast and actual amortization of capital additions. In its Decision, the BCUC stated that:

“the most effective solution to ensuring that amortization charges collected in revenue requirements for the test period appropriately reflect the capital assets that are actually utilized for the benefit of ratepayers during the same test period is to establish a new regulatory account.”³³⁰

The Amortization of Capital Additions Regulatory Account was continued in the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application and the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. By Order No. G-47-18 to the Previous Application, the BCUC approved that this regulatory account continue on an ongoing basis, that interest continue to be applied to the balance of this regulatory account, and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro’s weighted average cost of debt and forecast interest is recovered from the account each year.

BC Hydro is not requesting any changes to this account in this application.

7.8.3 Total Finance Charges Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC directed BC Hydro to defer to a regulatory account any differences between forecast and actual finance charges for fiscal 2009 and fiscal 2010. The Total Finance Charges Regulatory Account was continued by BCUC decisions on the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, the Fiscal 2012 to Fiscal 2014 Amended Revenue

³³⁰ Fiscal 2009 to Fiscal 2010 Revenue Requirement Application Decision, page 191.

1 Requirements Application and the Fiscal 2015 to Fiscal 2016 Revenue
2 Requirements Rate Application. By Order No. G-47-18 to the Previous Application,
3 the BCUC approved the continuation of this regulatory account on an ongoing basis,
4 and that the forecast account balance at the end of a test period be recovered over
5 the next test period.

6 BC Hydro is not requesting any changes to this account in this application.

7 **7.8.4 Rock Bay Remediation Regulatory Account**

8 By Order No. G-75-11, the BCUC approved the establishment of the Rock Bay
9 Remediation Regulatory Account for the deferral of actual expenditures in
10 fiscal 2011 related to the remediation of BC Hydro's Rock Bay property. By
11 Order No. G-55-12, the account was extended to defer actual remediation costs
12 incurred in fiscal 2012. By Order No. G-57-13, the account was extended to defer
13 actual remediation costs incurred in fiscal 2013.

14 As required by Direction No. 7, Order No. G-48-14 extended this period to include
15 remediation costs incurred in fiscal 2014 and later fiscal years. Direction No. 6
16 directed the amortization of specific amounts from the regulatory account in
17 fiscal 2015 and fiscal 2016.

18 The actual remediation costs deferred to the regulatory account for fiscal 2015 and
19 fiscal 2016 were lower than the amortization amounts specified by Direction No. 6,
20 resulting in a closing credit balance at the end of fiscal 2016. BCUC

21 Order No. G-47-18 to the Previous Application approved the refund of the closing
22 fiscal 2016 credit balance to ratepayers over the fiscal 2017 to fiscal 2019 period.

23 BCUC Order No. G-47-18 also approved the deferral of actual Rock Bay remediation
24 costs to this regulatory account each year and the amortization of forecast Rock Bay
25 remediation costs from this account each year from fiscal 2017 onwards. The Order
26 also approved that interest continue to be applied to the balance of this regulatory
27 account and that the forecast account balance at the end of a test period be

1 recovered over the next test period. Interest is applied to the account based on
2 BC Hydro's weighted average cost of debt and forecast interest is recovered from
3 the account each year.

4 Actual remediation costs over the fiscal 2017 to fiscal 2019 period were lower than
5 forecast remediation costs, resulting in a forecast closing credit balance in the
6 account at the end of fiscal 2019 of \$20.5 million. Consistent with BCUC
7 Order No. G-47-18, this credit balance will be refunded to ratepayers over the
8 fiscal 2020 to fiscal 2021 test period.

9 Remediation of the Rock Bay property was completed in fiscal 2019 and BC Hydro
10 is not forecasting the deferral of any further remediation costs to this account over
11 the test period. However, there may be minor variances between fiscal 2019
12 forecast and actual costs and forecast and actual interest applied to this account
13 during the test period. Therefore, BC Hydro plans to seek BCUC approval to close
14 the account in the next test period, once the balance of the account has been fully
15 recovered.

16 BC Hydro is not requested any changes to this account in this application.

17 **7.8.5 Arrow Water Systems Regulatory Account**

18 In the mid-1960s, BC Hydro relocated residents affected by the creation of the
19 Hugh Keenleyside Dam and Arrow Lakes Reservoir to the newly constructed towns
20 of Edgewood, Fauquier and Burton as well as the existing town of West Robson, all
21 part of the Regional District of Central Kootenay. BC Hydro built the drinking water
22 systems in Burton, Fauquier, and Edgewood when the towns were constructed, and
23 upgraded and assumed control of the West Robson drinking water system
24 (collectively known as the Arrow Water Systems) to compensate for impacts related
25 to construction of the Keenleyside Dam. On January 4, 2011, BC Hydro divested the
26 assets of the Arrow Water Systems to the Regional District of Central Kootenay.

By Order No. G-90-11, the BCUC approved the deferral of costs related to the divestiture of the Arrow Water Systems and established the Arrow Water Systems Regulatory Account and the Arrow Water Systems Provision Regulatory Account. The Arrow Water Systems Provision Regulatory Account is discussed further in section [7.8.19](#). Order No. G-48-14 set the amortization for the Arrow Water Systems Regulatory Account at \$4.7 million in fiscal 2015 and \$4.5 million in fiscal 2016, which reflected divestiture costs incurred to date.

Under the terms of the agreement with the Regional District of Central Kootenay on the divestiture of the Arrow Water Systems assets, BC Hydro makes an annual payment to the Regional District of Central Kootenay. This payment covers the water fees for the residents in the region who had water accounts in good standing with BC Hydro at the time of the transfer. BC Hydro will continue to make these payments until qualified residents are no longer on title for their properties. The cost of these payments is estimated at \$0.3 million per year. Consistent with BCUC Order No. G-47-18 to the Previous Application, this amount, and any other expenditures associated with divestiture are transferred from the Arrow Water Systems Provision Regulatory Account to the Arrow Water Systems Regulatory Account and a corresponding amount is amortized annually from the Arrow Water Systems Regulatory Account.

BC Hydro is not requesting any changes to this account in this application.

7.8.6 Remediation Regulatory Account

Starting in fiscal 2013 and in following years, BC Hydro began to incur expenditures related to asbestos remediation at its facilities. By Order No. G-7-13 the BCUC approved the establishment of the Asbestos Remediation Regulatory Account for unplanned asbestos remediation costs in fiscal 2013 and fiscal 2014. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer variances between forecast and actual asbestos remediation costs, to the account, on an ongoing basis.

1 By Order No. G-47-18 to the Previous Application, the BCUC approved an
2 expansion of the account scope to include costs incurred related to the compliance
3 with polychlorinated biphenyl regulations. To reflect this change, the BCUC also
4 approved that the name of the account be changed to the Remediation Regulatory
5 Account.

6 By Order No. G-47-18, the BCUC approved, starting in fiscal 2017, and on an
7 ongoing basis, that actual expenditures related to compliance with polychlorinated
8 biphenyl regulations and asbestos remediation be deferred to this account each
9 year, and forecast expenditures related to compliance polychlorinated biphenyl
10 regulations and asbestos remediation be amortized from this account each year.
11 Order No. G-47-18 also approved that interest continue to be applied to the
12 balances in the account and that the forecast account balance at the end of a test
13 period be recovered over the next test period. Interest is applied to the account
14 based on BC Hydro's weighted average cost of debt and forecast interest is
15 recovered from the account each year.

16 It continues to be appropriate to defer variances related to asbestos remediation to
17 the Remediation Regulatory Account. The rationale for deferring these variances is
18 the same as the rationale accepted by the BCUC for the deferral of variances related
19 to compliance with polychlorinated biphenyl regulations. In its Decision to the
20 Previous Application, the BCUC stated that:

21 *"Although the treatment of PCB is not prescribed by*
22 *Direction No. 7, as it is for asbestos costs, the Panel concurs*
23 *with BC Hydro that PCB costs are similar in nature to asbestos*
24 *costs in that they involve long-term estimates, the actual*
25 *expenditures are susceptible to variances in amount and timing*
26 *and differences from forecast due to the timing and scope of*
27 *work undertaken. Furthermore, the Panel finds the consistent*
28 *treatment of asbestos and PCB costs is reasonable."*³³¹

³³¹ BCUC Order No. G-47-18, Previous Application, page 65.

BC Hydro is not requesting any changes to this account in this application.

7.8.7 Real Property Sales Regulatory Account

By Order No. G-48-14, the Real Property Sales Regulatory Account was established to defer the variances between BC Hydro's actual and forecast real property gain/loss from real estate sales, with interest to be applied to the account based on BC Hydro's weighted average cost of debt. As described in section [7.9](#), BC Hydro incurs finance charges related to the balances in regulatory accounts. Accordingly, it is appropriate to apply interest to this regulatory account, consistent with the application of interest to other cash variance accounts.

The timing of completion of real estate transactions is difficult to forecast accurately. The Real Property Sales Regulatory Account smooths the recognition of gains and losses from real property sales that could otherwise impact rates in a particular year.

Since fiscal 2015, BC Hydro has been preparing surplus properties for sale. Activities have included market value appraisals and estimates, investigation and remediation of environmental contamination, working with municipalities on subdivision requirements, and consultation with First Nations.

The 2013 10 Year Rates Plan included a target of \$50 million of net gains from real property sales from fiscal 2015 to fiscal 2019. Consistent with this target, BC Hydro included \$10 million in forecast net gains from real property sales in each fiscal year in both the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application and the Previous Application.

BC Hydro has increased our net gains target from \$50 million to \$100 million and extended the timeframe to achieve this target to the end of fiscal 2024. This means that the Real Property Sales Regulatory Account is expected to self-clear based on the forecast gains and losses experienced from fiscal 2020 to fiscal 2024 and is forecast to have a zero balance by the end of fiscal 2024, subject to potential interest charges.

Consistent with this revised target, BC Hydro has included \$10 million in forecast net gains from real property sales in both fiscal 2020 and fiscal 2021, in this application.

Pursuant to Direction No. 8, the existing balance in this regulatory account as at March 31, 2019, is recoverable from ratepayers. If this regulatory account was discontinued at the end of fiscal 2019, the balance would be amortized into rates starting in fiscal 2020. However, the revised target of \$100 million in net gains from real property sales is expected to clear the balance in this regulatory account by the end of fiscal 2024. Maintaining the Real Property Sales Regulatory Account means that the existing account balance will not be borne by ratepayers.

BC Hydro is not requesting any changes to this account in this application.

7.8.8 Mining Customer Payment Plan Regulatory Account

In accordance with section 3(2) of Order in Council No. 123, issued on February 29, 2016, BCUC Order No. G-34-16 authorized BC Hydro to establish the Mining Customer Payment Plan Regulatory Account to defer to future fiscal years amounts equal to the sum of the following related to mining customers participating in the Mining Customer Payment Plan Program:

- (i) The account balances of mining customers, if those account balances are impaired;
- (ii) Any other amounts that are payable to BC Hydro by mining customers before the closing date and that are impaired; and
- (iii) Any taxes paid by BC Hydro on behalf of mining customers on the account balances referred to in subparagraph (i) and amounts referred to in subparagraph (ii).

This Order arose from the Government of B.C.'s decision to allow companies operating metal and coal mines in B.C. to temporarily defer a portion of their electricity payments during periods of low commodity prices.

BCUC Order No. G-34-16 also directed BC Hydro to reduce the Mining Customer Payment Plan Regulatory Account by an amount collected from an applicable mining customer, and to include in the account, interest determined in a fiscal year at the rate of BC Hydro's weighted average cost of debt in that fiscal year.

BC Hydro is not requesting any changes to this account in this application.

7.8.9 Customer Crisis Fund Regulatory Account

By Order No. G-166-17, the BCUC approved the establishment of the Customer Crisis Fund Regulatory Account.

By Order No. G-5-17 to the 2015 Rate Design Application, the BCUC directed BC Hydro to file a proposal for the establishment of a crisis intervention fund pilot program for residential customers who have arrears with BC Hydro and are unable to pay their electricity bills.³³² By Order No. G-166-17, the BCUC approved the Customer Crisis Fund pilot program on a three year basis.

The costs related to the Customer Crisis Fund pilot program are driven by program participation and could vary from forecast. In addition, there will likely be variations in the timing of revenues and costs over the duration of the Customer Crisis Fund pilot program.

Accordingly, in its application to establish the pilot program, BC Hydro proposed that the net difference between the revenues collected under the Customer Crisis Fund Rate Rider and the incremental costs related to the Customer Crisis Fund pilot program in each fiscal year be transferred to the Customer Crisis Fund Regulatory Account. Any remaining balance in the Customer Crisis Fund Regulatory Account at the end of the Customer Crisis Fund pilot program would be to the account of residential ratepayers. Recovery or refund of the balance will be addressed after

³³² 2015 Rate Design Application Decision, BCUC Order No. G-5-17, pages 97 to 98.

1 completion of the pilot program. This approach ensures that residential ratepayers
2 only pay the actual net costs of the Customer Crisis Fund pilot program.

3 BC Hydro is not requesting any changes to this account in this application.

4 **7.8.10 Foreign Exchange Gains and Losses Regulatory Account**

5 By Order No. G-47-02, the BCUC approved the deferral and amortization of foreign
6 exchange gains and losses on the translation of foreign denominated long-term
7 monetary items, using the straight-line pool method, from fiscal 2003 onwards. More
8 specifically, deferred foreign currency translation gains and losses related to
9 long-term debt are amortized over the weighted average remaining term to maturity
10 of the foreign denominated long-term debt portfolio. Deferred foreign currency
11 translation gains and losses related to sinking funds are amortized over the weighted
12 average remaining term to maturity of the sinking fund portfolio.

13 BC Hydro is not requesting any changes to this account in this application.

14 **7.8.11 Non-Current Pension Costs Regulatory Account**

15 By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements
16 Application, the BCUC approved the establishment of a regulatory account to defer
17 the difference between forecast and actual non-current pension costs in fiscal 2010.
18 The Fiscal 2011 Revenue Requirement Application Negotiated Settlement
19 Agreement extended this regulatory account for fiscal 2011 and directed that the
20 closing fiscal 2011 balance be amortized over a five-year period, beginning in
21 fiscal 2012.

22 BCUC Order No. G-77-12A extended the account for fiscal 2012 to fiscal 2014, and
23 expanded the scope of the account to include the difference between forecast and
24 actual non-current other post-employment benefit costs, beginning in fiscal 2012. In
25 accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to
26 continue to defer to the account variances between forecast and actual non-current
27 pension costs, on an ongoing basis.

1 By Order No. G-47-18 to the Previous Application, the BCUC approved that the
2 portion of the forecast account balance at the start of a test period related to the
3 variances transferred to the account during the previous test period be amortized
4 over the expected average remaining service life (**EARSL**) of the active plan
5 members at the start of the test period. EARSL is determined by BC Hydro's actuary
6 and is currently 12 years.

7 In accordance with BCUC Order No. G-47-18, the discount rate used to forecast
8 post-employment benefit plan costs is based on the market discount rate in effect at
9 the time the forecast was prepared.

10 As discussed in section [7.3](#), actuarial gains and losses are sensitive to changes in
11 market discount rates, rates of return on pension plan assets and significant
12 changes in key actuarial assumptions. This means that annual actuarial gains and
13 losses are subject to large positive and negative fluctuations. For example, the
14 elimination of Medical Services Plan Premiums resulted in significant actuarial gains
15 in fiscal 2018 and fiscal 2019 as shown in Schedule 2.2 of Appendix A. In the
16 absence of regulatory approval to defer actuarial gains and losses to the
17 Non-Current Pension Costs Regulatory Account, this actuarial gain would have been
18 captured in retained earnings and ratepayers would not have received the benefit of
19 this actuarial gain. Accordingly, BC Hydro believes it is appropriate to continue to
20 defer, on an ongoing basis, the variances between its actual and forecast
21 non-current pension costs to the Non-Current Pension Costs Regulatory Account
22 and to continue to amortize these amounts over EARSL.

23 Please refer to Chapter 5G, section 5G.9 for further information on Non-Current
24 Service Costs.

25 BC Hydro is not requesting any changes to this account in this application.

7.8.12 PEB Current Pension Costs Regulatory Account

By Order No. G-47-18 to the Previous Application, the BCUC approved the establishment of the Post-Employment Benefit (PEB) Current Pension Costs Regulatory Account to defer the annual variance between forecast and actual costs related to the operating cost portion of post-employment benefits current pension costs, on an ongoing basis. Order No. G-47-18 also approved that the forecast account balance at the end of a test period be recovered over the next test period.

In accordance with BCUC Order No. G-47-18, the discount rate used to forecast post-employment benefit plan costs is based on the market discount rate in effect at the time the forecast was prepared.

Please refer to Chapter 5G, section 5G.9 for further information on Current Service Costs.

BC Hydro is not requesting any changes to this account in this application.

7.8.13 Debt Management Regulatory Account

By Order No. G-42-16, the BCUC approved the establishment of the Debt Management Regulatory Account, to capture mark-to-market gains and losses of financial contracts that hedge future long-term debt. Hedging the interest rate on future long-term debt enables BC Hydro to mitigate interest rate risk on future long-term debt issuances.

Since fiscal 2017, BC Hydro has locked in interest rates on forecast future long-term debt issuances by entering into financial contracts that hedge the interest rate risk in order to create certainty of financing costs associated with future planned expenditures. In accordance with Order No. G-42-16, the gains and losses from financial contracts that hedge future long-term debt are recorded in the Debt Management Regulatory Account and amortized over the remaining term of the associated long-term debt issuances. These gains and losses are amortized in the

1 test period following the test period in which the long-term debt associated with a
2 particular hedge is issued.

3 BC Hydro is not requesting any changes to this account in this application.

4 **7.8.14 First Nations Costs Regulatory Account**

5 By Order No. G-53-02, the BCUC approved the deferral of costs related to
6 negotiations and settlements with First Nations, and approved the amortization of
7 actual negotiation costs and approved settlement costs, over a ten-year period.
8 Settlement payments transferred to the First Nations Costs Regulatory Account from
9 the First Nations Provisions Regulatory Account are not amortized or recovered in
10 rates, pending BCUC approval to do so. In accordance with BCUC
11 Order No. G-11-08, when a settlement is completed, BC Hydro must submit an
12 application to the BCUC for approval to recover the settlement payment in rates. The
13 nature of these settlements is discussed further in section [7.8.17](#). BCUC
14 Order No. G-48-14 directed the amortization of specific amounts from the account
15 for fiscal 2015 and fiscal 2016, and also directed that interest be applied on the
16 account going forward.

17 Actual transfers to the account in fiscal 2015 and fiscal 2016 were different from the
18 amounts on which the specific amortization in BCUC Order No. G-48-14 was based,
19 which resulted in BC Hydro recording higher amortization than if the amortization
20 had been calculated on actual transfers. This resulted in a credit amount which was
21 refunded to ratepayers over the fiscal 2017 to fiscal 2019 period, consistent with
22 BCUC Order No. G-47-18 to the Previous Application.

23 As described in section [7.9](#), BC Hydro incurs finance charges related to the
24 balances in regulatory accounts. Accordingly, it is appropriate that interest should be
25 applied to this regulatory account, consistent with the application of interest to other
26 cash variance accounts.

By Order No. G-47-18 to the Previous Application, the BCUC approved, starting in fiscal 2017, and on an ongoing basis that:

- (i) Actual lump sum settlement payments be deferred to this account each year, and forecast lump sum settlement payments be amortized over a ten-year period, starting in the year of payment;
- (ii) Actual annual settlement payments be deferred to this account each year, and forecast annual settlement payments be amortized in the year of payment;
- (iii) Actual negotiation costs be deferred to this account each year, and actual negotiation costs be recovered from the account each year;
- (iv) Interest continue to be applied to the balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's weighted average cost of debt, and forecast interest charged to the account be amortized from the account each year;
- (v) The forecast account balance at the end of a test period related to the difference between the amortization of the forecast annual and lump sum settlement payments and the calculation of amortization based on the actual annual and lump sum settlement payments during that test period be recovered over the next test period; and
- (vi) The forecast account balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period be recovered over the next test period.

For items (i) and (ii) above, the year of payment refers to the year the payment is forecast to be made.

BC Hydro is not requesting any changes to this account in this application.

7.8.15 Pre-1996 Contributions in Aid of Construction Regulatory Account

In fiscal 2006 BC Hydro retained Gannett Fleming to complete a depreciation study, which was filed as part of the Fiscal 2007 to Fiscal 2008 Revenue Requirements Application. Gannett Fleming recommended that the amortization period for assets referred to as “Profile ID 99403 Distribution Pre-1996 Contributions in Aid” be increased from the then-approved period of 25 years to 45 years.

However, section 7(iv) of the Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Negotiated Settlement Agreement approved by BCUC Order No. G-143-06 committed BC Hydro to maintain the amortization period for these assets at 25 years. In its financial records BC Hydro changed the amortization period for these assets from 25 to 45 years to match the depreciation study, and implemented the Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Negotiated Settlement Agreement commitment by creating a regulatory account to capture the difference in the revenue requirement impacts of a 45-year amortization period and a 25-year amortization period. This regulatory account will be fully amortized at the end of fiscal 2040.

BC Hydro is not requesting any changes to this account in this application.

7.8.16 SMI Regulatory Account

By Order No. G-64-09, the BCUC approved the establishment of the SMI (Smart Metering and Infrastructure Program) Regulatory Account to defer the operating costs incurred by BC Hydro related to the Smart Metering and Infrastructure Program in fiscal 2009. By Order No. G-67-10, the BCUC approved the deferral of these costs for fiscal 2010. BCUC Order No. G-115-11 authorized BC Hydro to include its actual fiscal 2011 Smart Metering and Infrastructure Program operating costs up to \$5.8 million in the SMI Regulatory Account. BCUC Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application approved the deferral of actual net operating costs, amortization on capital assets,

1 finance charges, and return on equity related to the SMI program from fiscal 2012 to
2 fiscal 2014, to the SMI Regulatory Account.

3 By Order No. G-166-13, and in accordance with section 3(2) of Direction No. 4,
4 BC Hydro was directed to defer to the account:

- 5 • Program costs;
- 6 • Investigation costs and infrastructure costs that are not recovered from eligible
7 customers at premises where a legacy meter or radio-off meter is installed; and
- 8 • Costs related to smart meters, which are incurred during the period
9 January 1, 2013 to March 31, 2014.

10 By Order No. G-48-14 to the Fiscal 2015 to Fiscal 2016 Revenue Requirements
11 Rate Application, the BCUC approved the amortization of specific amounts in
12 fiscal 2015 and fiscal 2016 from the SMI Regulatory Account and also approved
13 deferral of the net operating costs incurred in fiscal 2015 to fiscal 2016 related to the
14 SMI Program, to the account. As the SMI Program is now complete and
15 operationalized, no further additions are being made to this regulatory account.

16 By Order No. G-47-18 to BC Hydro's Previous Application, the BCUC approved the
17 recovery of the fiscal 2016 closing account balance over a period of 13 years,
18 starting in fiscal 2017, which is the remaining period of the original 15-year
19 amortization period proposed in the Regulatory Accounts Report filed in the
20 Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. The 15-year
21 amortization is based on the average life of SMI assets. BCUC Order No. G-47-18
22 also approved that interest continue to be applied to the balance of this regulatory
23 account. Interest is applied to the account at BC Hydro's weighted average cost of
24 debt and forecast interest is recovered from the account each year.

25 BC Hydro is not requesting any changes to this account in this application.

7.8.17 First Nations Provisions Regulatory Account

By Order No. G-56-06, the BCUC approved the establishment of a regulatory asset corresponding to the amount of a loss provision that BC Hydro recorded on its financial statements as required under the accounting standards related to two First Nations claims. By Order No. G-11-08, the BCUC amended the First Nations Provisions Regulatory Account to allow the balance of the regulatory account to reflect loss provisions as required under the accounting standards, related to any First Nations claim, and to allow the periodic adjustment of the balance of the regulatory account to reflect adjustments to the loss provisions required under the accounting standards.

BC Hydro's settlements with First Nations may include both lump sum payments and annual payments. When settlement payments are made, corresponding amounts are transferred from the First Nations Provisions Regulatory Account to the First Nations Costs Regulatory Account, and recovered in rates through amortization of that regulatory account, as discussed in section [7.8.14](#).

BC Hydro is not requesting any changes to this account in this application.

7.8.18 Environmental Provisions Regulatory Account

By Order No. G-88-10, the BCUC approved the establishment of the Environmental Provisions Regulatory Account in the amount of the loss provision liability recognized by BC Hydro in its financial statements, related to compliance with the polychlorinated biphenyl regulations and remediation of environmental contamination at Rock Bay. Order No. G-88-10 also approved periodic adjustments to the amounts in the regulatory account to match the changes required under the accounting standards in the loss provision liability. By Order No. G-7-13, the terms of the Environmental Provisions Regulatory Account were expanded to include the loss provision liability related to asbestos remediation at BC Hydro's facilities.

As BC Hydro makes actual expenditures related to compliance with the polychlorinated biphenyl regulations, the remediation of Rock Bay and the remediation of asbestos at its facilities, the balance in the Environmental Provisions Regulatory Account is reduced accordingly.

Actual costs of remediation activities at Rock Bay are deferred to the Rock Bay Remediation Regulatory Account as they are incurred, as described in section [7.8.4](#), and the provision is reduced by an equal amount. Remediation of the Rock Bay property was completed in fiscal 2019, and the balance in the Environmental Provisions Regulatory Account related to Rock Bay has been reduced accordingly.

Actual costs related to asbestos remediation are deferred to the Remediation Regulatory Account as they are incurred, as described in section [7.8.6](#), and the provision is reduced by an equal amount.

Actual costs related to compliance with polychlorinated biphenyl regulations, were expensed as incurred until the end of fiscal 2016, and the Environmental Provisions Regulatory Account was reduced by an equal amount. By Order No. G-47-18 to the Previous Application, BCUC approved that, starting in fiscal 2017, and on an ongoing basis, actual costs related to compliance with polychlorinated biphenyl regulations be deferred to the Remediation Regulatory Account as they are incurred and the provision be reduced by an equal amount. This is similar to the treatment of the costs associated with asbestos remediation.

The actual balances in the Rock Bay Remediation Regulatory Account and the Remediation Regulatory Account are recovered through the mechanisms discussed in sections [7.8.4](#) and [7.8.6](#), respectively.

BC Hydro is not requesting any changes to this account in this application.

7.8.19 Arrow Water Systems Provision Regulatory Account

By Order No. G-90-11, the BCUC approved the establishment of the Arrow Water Systems Provision Regulatory Account and the Arrow Water Systems Regulatory

Account. The Arrow Water Systems Regulatory Account is discussed further in section [7.8.5](#).

BC Hydro is required under the accounting standards to record a loss provision liability in regards to the divestiture of the Arrow Water Systems. The recording of the loss provision liability and the corresponding Arrow Water Systems Provision regulatory asset preserve BC Hydro's ability to seek recovery of actual costs in rates. As payments are made the provision account is drawn down and corresponding amounts are transferred to the Arrow Water Systems Regulatory Account and amortized into rates. The balance in the Arrow Water Systems Provision Regulatory Account represents BC Hydro's obligation to pay the water fees of the regions qualifying residents until such time that those residents are no longer on title for their properties.

BC Hydro is not requesting any changes to this account in this application.

7.8.20 IFRS Property, Plant and Equipment Regulatory Account

The IFRS Property, Plant and Equipment Regulatory Account enables the deferral of overhead costs that can no longer be capitalized under IFRS, as they are not directly attributable to the construction of an asset. Under CGAAP, costs related to administration and general overhead were eligible for capitalization to Property, Plant, and Equipment.

BCUC Order No. G-77-12A to BC Hydro's Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application implemented BC Hydro's proposal that overhead costs that can no longer be capitalized be deferred and transitioned into operating expenditures over ten years to avoid immediate and significant rate impacts. BCUC Order No. G-77-12A implemented this proposal and set the amortization period at 40 years, starting in fiscal 2013.

In the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application, BC Hydro included a proposal to transition the overhead costs that could no longer

be capitalized under IFRS into rates over a ten-year period. Under this proposal 100 per cent of ineligible overhead costs were charged to the IFRS Property, Plant and Equipment Regulatory Account in fiscal 2012. Starting in fiscal 2013, the percentage of the ineligible overhead costs to be charged to the regulatory account was reduced by 10 per cent each year.

The actual and forecast annual additions and amortization for the IFRS Property, Plant and Equipment Regulatory Account are set out in [Table 7-7](#) below. As indicated in the table and consistent with BC Hydro's proposal, additions to the account are forecast to be zero by fiscal 2022.

**Table 7-7 IFRS Property, Plant and Equipment
Regulatory Account**

(\$ million)	Additions	Amortization
Fiscal 2012 Actual	221.8	-
Fiscal 2013 Actual	229.6	4.7
Fiscal 2014 Actual	179.5	8.7
Fiscal 2015 Actual	156.8	15.9
Fiscal 2016 Actual	134.4	19.8
Fiscal 2017 Actual	112.0	23.2
Fiscal 2018 Actual	89.6	26.0
Fiscal 2019 Forecast	67.2	28.2
Fiscal 2020 Plan	44.8	29.9
Fiscal 2021 Plan	22.4	31.0
Fiscal 2022 Plan	0.0	31.6

In the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application, BC Hydro also proposed to amortize the additions to the IFRS Property, Plant and Equipment Regulatory Account over 40 years. This amortization period was based on the composite life of BC Hydro's assets so that the overhead costs would be matched with the benefits of the underlying assets.

If BC Hydro had recognized the impact of the transition to IFRS in rates at the time of the transition, the rate impact for customers would have been immediate and significant. Amortizing these costs over a 40-year period allows these costs to be

recovered over a similar period of time as was required under CGAAP, the accounting rules that BC Hydro followed prior to IFRS. Accordingly, a 40-year amortization period also results in approximately the same revenue requirement impact under IFRS as under the previous CGAAP rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting standards. BC Hydro believes that the existing amortization period of 40 years continues to be appropriate.

BC Hydro is not requesting any changes to this account in this application.

7.8.21 IFRS Pension Regulatory Account

Upon the transition to IFRS in fiscal 2013, BC Hydro was required to recognize all unamortized actuarial gains and losses on the pension and other post-employment benefit plans, not previously recognized in its financial statements.

In the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application, BC Hydro requested the establishment of the IFRS Pension Regulatory Account with an opening liability balance equal to the actual unamortized actuarial gains and losses on the pension and other post-employment benefit plans, which BC Hydro had to recognize in its financial statements at the time of conversion to IFRS. BCUC Order No. G-77-12A implemented this request and also set the amortization period at 20 years on a straight-line basis, starting in fiscal 2013.

Amortizing these costs over a 20-year period results in approximately the same revenue requirement impact under IFRS as under the previous CGAAP rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting standards. BC Hydro believes that the existing amortization period of 20 years continues to be appropriate.

BC Hydro is not requesting any changes to this account in this application.

...

**BC Hydro Fiscal 2022
Revenue Requirements Application**

**Appendix V
Debt Management Regulatory Account
Status Report – Fiscal 2020**

**BC Hydro Fiscal 2020 Annual Report to
the British Columbia Utilities Commission**

Appendix B

**Debt Management Regulatory Account
Annual Status Report**

April 1, 2019 to March 31, 2020

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Background

On March 30, 2016, the BCUC issued Order No. G-42-16 which authorized BC Hydro to establish a Debt Management Regulatory Account (**DMRA**) to capture mark-to-market gains and losses on financial contracts that hedge future long-term debt to mitigate interest rate risk on future long-term debt that BC Hydro intends to issue. In compliance with Directive 4 of that Order, BC Hydro provides below its annual report on the DMRA.

Report as at March 31, 2020

During fiscal 2020, BC Hydro did not enter into any further future debt hedges (**FDHs**) to mitigate interest rate risk on future long-term debt that BC Hydro intends to issue. The existing outstanding hedges consist of 10-year and 30-year interest rate swaps and 30-year Government of Canada bond locks, with remaining contract maturity dates ranging from approximately three months to 4.2 years and forecast borrowing yields ranging from 2.60 per cent to 3.67 per cent.

Since the establishment of the DMRA, a total of \$10.0 billion of FDHs have been placed, of which \$5.0 billion remain outstanding. Based on BC Hydro's 2020/21 – 2022/23 Service Plan, at March 31, 2020, BC Hydro had hedged approximately 75 per cent of forecast total borrowing requirements from fiscal 2021 to fiscal 2025. The details of all FDHs are included in [Appendix 1](#).

At March 31, 2020, the DRMA had a balance of \$953 million (after amortization), which included net unrealized losses of \$1,011 million on the \$5.0 billion of outstanding FDHs and net realized gains of \$71 million on the \$5.0 billion of settled FDHs. This was a net change of \$790 million from the balance at March 31, 2019 of \$163 million to the balance at March 31, 2020 of \$953 million. The \$790 million change was due to:

-
- 1 • \$12 million related to the amortization of net realized gains on the \$4.0 billion of
2 FDHs settled during fiscal 2017 to fiscal 2019;
 - 3 • \$35 million related to decreases in the value of the \$1.0 billion of FDHs that
4 were settled during fiscal 2020; and
 - 5 • \$743 million related to decreases in the unrealized mark-to-market value of the
6 \$5.0 billion of outstanding FDHs.

7 The decrease in the value of both the fiscal 2020 settled and outstanding FDHs is
8 due to a significant decrease in long-term interest rates during fiscal 2020.

9 Lower long-term interest rates result in lower interest costs on the associated future
10 long-term debt issues when issued. These lower interest costs on the associated
11 debt issues provide an offset to the impact of the FDH losses. This results in the net
12 effect of locking in the interest rate and mitigating interest rate risk on future
13 long-term debt that BC Hydro intends to issue.

14 The net unrealized loss of \$1,011 million relating to the \$5.0 billion in outstanding
15 FDHs remains sensitive to changes in long-term yields and will continue to change
16 until the hedges are settled. A 100-basis point change in long-term yields would
17 result in a change of approximately \$0.8 billion to \$1.0 billion in the value of the
18 \$5.0 billion in outstanding FDHs.

19 Any realized gains and losses will be amortized over the remaining term of the
20 issued debt starting at the beginning of the test period following the test period
21 during which the long-term debt associated with a particular hedge is issued. As a
22 result, the effective interest rate on hedged debt is a combination of the gain or loss
23 on the settled FDH and the yield of the underlying debt issuance.

**BC Hydro Fiscal 2020 Annual Report to
the British Columbia Utilities Commission**

Appendix B

Appendix 1

Future Debt Hedges Report

Future Debt Hedges Report

As of March 31, 2020

(in millions of Canadian dollars)

Name	Execution Date	Transaction Type	Forecast Debt Issuance & Contract Maturity Year	Contract Settlement Date	Hedge Term	Notional Amount	Forecast Borrowing Yield	Actual Yield	Fair Market Value ²	Settlement Value ²	Total DMRA Balance Before Amortization ²	Amortization	DMRA Balance ²
Hedges Placed F2017													
FDH1 ¹	2016-05-16	Bond Lock	F2017	16-Nov	10 years	200	2.24%	3.01%		2.7	2.7	(0.1)	2.6
FDH2A	2016-05-11	Bond Lock	F2017	16-Sep	30 years	200	2.97%	3.00%		(11.3)	(11.3)	0.4	(10.9)
FDH2B	2016-05-12	Bond Lock	F2017	16-Sep	30 years	100	3.01%	3.00%		(6.7)	(6.7)	0.2	(6.5)
FDH3	2016-05-18	Bond Lock	F2018	17-Mar	10 years	300	2.36%	2.35%		8.0	8.0	(1.0)	7.0
FDH4	2016-05-24	Bond Lock	F2018	17-Oct	10 years	200	2.38%	2.37%		7.4	7.4	(0.9)	6.5
FDH5	2016-05-31	Bond Lock	F2018	17-Jun	30 years	200	3.04%	2.87%		0.1	0.1	(0.0)	0.1
FDH6	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.09%	1.83%		17.0	17.0	(2.1)	15.0
FDH7	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.08%	1.82%		17.2	17.2	(2.1)	15.1
FDH8	2016-09-26	Swap	F2018	17-Sep	30 years	200	2.64%	2.27%		40.9	40.9	(1.4)	39.5
FDH9	2016-09-29	Swap	F2019	18-May	10 years	200	2.09%	1.84%		22.7	22.7	(2.3)	20.3
FDH10	2016-10-06	Swap	F2019	18-Apr	30 years	200	2.76%	2.14%		38.7	38.7	(1.3)	37.4
FDH11	2016-06-08	Swap	F2019	18-Sep	10 years	300	2.53%	2.16%		22.4	22.4	(2.3)	20.1
FDH12	2016-06-08	Swap	F2019	18-Sep	10 years	200	2.54%	2.17%		14.7	14.7	(1.5)	13.2
FDH13	2016-06-14	Swap	F2020	19-Jun	10 years	300	2.54%	2.18%		(0.4)	(0.4)	0.0	(0.4)
FDH14	2016-06-22	Swap	F2020	19-Oct	10 years	200	2.74%	2.44%		(3.1)	(3.1)	0.0	(3.1)
FDH15	2016-10-12	Swap	F2020	19-Oct	10 years	200	2.57%	2.24%		0.7	0.7	0.0	0.7
FDH16	2016-10-13	Swap	F2021		10 years	300	2.60%		(23.0)		(23.0)		(23.0)
FDH17	2016-10-13	Swap	F2021		10 years	200	2.60%		(15.3)		(15.3)		(15.3)
FDH18	2016-10-20	Swap	F2021		10 years	300	2.69%		(25.1)		(25.1)		(25.1)
FDH19	2016-10-20	Swap	F2021		10 years	200	2.69%		(16.8)		(16.8)		(16.8)
Subtotal						\$4,400			(\$80.2)	\$171.0	\$90.8	(\$14.4)	\$76.4
Hedges Placed F2018													
FDH20	2017-09-29	Bond Lock	F2019	18-Jul	10 years	200	2.96%	2.88%		(1.6)	(1.6)	0.2	(1.4)
FDH21	2017-10-03	Bond Lock	F2019	18-Jul	10 years	200	3.00%	2.92%		(2.2)	(2.2)	0.2	(2.0)
FDH22	2017-09-29	Bond Lock	F2019	18-Jul	30 years	200	3.35%	3.36%		(17.3)	(17.3)	0.6	(16.7)
FDH23A	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.84%		(0.4)	(0.4)	0.0	(0.3)
FDH23B	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.87%		(0.4)	(0.4)	0.0	(0.3)
FDH24A	2017-10-02	Bond Lock	F2019	18-Aug	30 years	100	3.36%	3.35%		(6.4)	(6.4)	0.2	(6.2)
FDH24B	2017-10-03	Bond Lock	F2019	18-Aug	30 years	100	3.38%	3.37%		(6.8)	(6.8)	0.2	(6.6)
FDH25	2017-09-28	Bond Lock	F2019	18-Aug	30 years	250	3.37%	3.36%		(16.7)	(16.7)	0.5	(16.1)
FDH26/27	2018-01-29	Swap	F2020	19-Jun	30 years	50	3.44%	3.16%		(6.7)	(6.7)	0.0	(6.7)
FDH28	2018-02-05	Swap	F2021		30 years	75	3.64%		(27.0)		(27.0)		(27.0)
FDH29	2018-02-05	Swap	F2021		30 years	75	3.64%		(27.0)		(27.0)		(27.0)
FDH30/31	2018-02-08	Swap	F2022		30 years	175	3.67%		(62.9)		(62.9)		(62.9)
FDH32	2018-02-06	Swap	F2022		30 years	100	3.60%		(33.9)		(33.9)		(33.9)
FDH33	2018-02-07	Swap	F2022		30 years	100	3.58%		(33.5)		(33.5)		(33.5)
FDH34/35	2018-02-01	Swap	F2023		30 years	250	3.52%		(76.6)		(76.6)		(76.6)
FDH36/37	2018-01-24	Swap	F2023		30 years	200	3.40%		(55.8)		(55.8)		(55.8)
Subtotal						\$2,275			(\$316.6)	(\$58.4)	(\$375.0)	\$2.0	(\$373.0)
Hedges Placed F2019													
FDH38	2018-12-07	Swap	F2022		10 years	125	3.33%		(19.1)		(19.1)		(19.1)
FDH39	2018-12-06	Swap	F2023		10 years	100	3.40%		(14.3)		(14.3)		(14.3)
FDH40	2018-12-07	Swap	F2023		10 years	125	3.41%		(17.7)		(17.7)		(17.7)
FDH41	2018-12-07	Swap	F2024		10 years	175	3.46%		(24.6)		(24.6)		(24.6)
FDH42	2018-12-06	Swap	F2024		30 years	175	3.62%		(55.1)		(55.1)		(55.1)
FDH43	2019-01-15	Bond Lock	F2020	19-Jun	30 years	150	3.13%	3.07%		(18.8)	(18.8)	0.0	(18.8)
FDH44	2019-01-16	Bond Lock	F2020	19-Sep	30 years	125	3.17%	3.24%		(23.1)	(23.1)	0.0	(23.1)
FDH45A	2019-01-17	Bond Lock	F2021		30 years	200	3.20%		(47.6)		(47.6)		(47.6)
FDH45B	2019-01-17	Bond Lock	F2021		30 years	125	3.20%		(29.8)		(29.8)		(29.8)
FDH46A	2019-01-15	Swap	F2021		30 years	100	3.43%		(30.6)		(30.6)		(30.6)
FDH46B	2019-01-16	Swap	F2021		30 years	225	3.49%		(72.1)		(72.1)		(72.1)
FDH47	2019-01-08	Swap	F2022		10 years	275	3.15%		(37.7)		(37.7)		(37.7)
FDH48	2019-01-09	Swap	F2022		30 years	100	3.41%		(29.6)		(29.6)		(29.6)
FDH49	2019-01-09	Swap	F2022		10 years	300	3.22%		(41.7)		(41.7)		(41.7)
FDH50	2019-01-10	Swap	F2022		30 years	175	3.41%		(50.9)		(50.9)		(50.9)
FDH51	2019-01-14	Swap	F2023		10 years	250	3.26%		(32.8)		(32.8)		(32.8)
FDH52	2019-01-10	Swap	F2023		10 years	125	3.27%		(16.2)		(16.2)		(16.2)
FDH53	2019-01-11	Swap	F2023		30 years	100	3.42%		(28.0)		(28.0)		(28.0)
FDH54	2019-01-09	Swap	F2024		10 years	175	3.33%		(22.6)		(22.6)		(22.6)
FDH55	2019-01-08	Swap	F2024		30 years	125	3.44%		(34.4)		(34.4)		(34.4)
FDH56	2019-01-15	Swap	F2025		10 years	75	3.39%		(9.5)		(9.5)		(9.5)
Subtotal						\$3,325			(\$614.4)	(\$41.9)	(\$656.3)	\$0.0	(\$656.3)
Total						\$10,000			(\$1,011.2)	\$70.7	(\$940.5)	(\$12.4)	(\$952.9)

¹ Actual debt was a 30 year issue.

² Gain / (loss) deferred to the Debt Management Regulatory Account

BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

Appendix B

Appendix 2

Glossary for Appendix 1

Appendix 2

Name	BC Hydro reference for each individual FDH.
Execution Date	Date the FDH was entered into.
Transaction Type	Type of Future Debt Hedge Bond Locks – contracts with financial institutions that are based on the performance of Government of Canada Treasury Bonds. Under a Bond Lock, BC Hydro will effectively sell a particular Government of Canada Bond at the current interest rate and effectively repurchase it at a pre-defined future date at the then-prevailing market interest rate Forward Swaps – contracts with financial institutions whereby BC Hydro will pay the current interest rate on the Interest Rate Swap ¹ and agree to receive the prevailing interest rate on the Interest Rate Swap at a pre-defined future date.
Forecast Debt Issuance and Contract Maturity Year	Fiscal year the FDH derivative contract is forecast to be unwound and cash settled (set at the inception of the hedge) and the related future debt is expected to be issued.
Contract Settlement Date	Date the FDH derivative was actually unwound and cash settled.
Hedge Term	The term of the future debt issue that is being hedged (i.e., either a 10-year debt issue or a 30-year debt issue).
Notional Amount	The dollar value of the FDH derivative. The notional amount of the derivative will be equal to the principal amount of the related future debt issue.
Forecast Borrowing Yield	The anticipated yield on a particular future debt issue on the day the FDH was executed. The forecast borrowing yield is subject to change based on the difference between the change in the yield on Province of BC Bonds vs. the change in the yield on the underlying FDHs (Bond lock or Forward Swap) since the inception of the hedges. The actual yield will only be known upon the cash settlement of the FDH and the issuance of the related future debt.
Actual Yield	The effective yield on the future debt issuance taking into account the gain or loss on the related FDH.
Fair Market Value	The mark to market value of the FDHs that are not yet cash settled.
Settlement Value	The amount of cash paid out by BC Hydro or received by BC Hydro upon the unwinding and cash settlement of the FDH. A loss on the FDH would involve a cash payment by BC Hydro and a gain on the FDH would involve a receipt of cash by BC Hydro.
Total DMRA Balance Before Amortization	The amount of gain or loss on FDHs recorded in the DMRA since inception. Comprised of mark to market gains and losses and settlement gains and losses.

¹ A Canadian Interest Rate Swap is an agreement between two counterparties that agree to exchange an interest payment based on the CDOR Canadian Dollar Offer Rate index.

Appendix 2

Amortization	The amount removed from the DMRA and included in Net Income. The gains or losses in the DMRA will be amortized over the remaining term of the associated long-term debt issuances, commencing at the beginning of the test period subsequent to the test period in which the long-term debt to which the Future Debt Hedge is associated is issued. The combination of the amortization of the DMRA and the interest charges on the underlying debt result in the effective yield on the debt at its hedged rate.
DMRA Balance	The balance in the DMRA at the report date.

BC Hydro Fiscal 2022
Revenue Requirements Application

Appendix W
DSM Annual Report



Fred James

Chief Regulatory Officer

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bchydroregulatorygroup@bchydro.com

July 10, 2020

Ms. Marija Tresoglavic
Acting Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Tresoglavic:

**RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2005/F2006 Revenue Requirements Application
BCUC Decision: October 29, 2004; Directive 69 (page 201)
(AMENDED pursuant to 2006 Integrate Electricity Plan and
2006 Long-Term Acquisition Plan
BCUC Decision: May 11, 2006; Directive 16 (pages 145 to 146)
2008 Long-Term Acquisition Plan
BCUC Decision: July 27, 2009; Directive 36 (page 184))
Fiscal 2017 – Fiscal 2019 Revenue Requirements Application
BCUC Decision: March 1, 2018; Directive 23 (page 84)
F2020 Demand-Side Management Activities Annual Report**

BC Hydro writes to provide its Report on Demand-Side Management Activities for the 12 months ending March 31, 2020.

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

st/ma

Enclosure (1)



Report on Demand-Side Management Activities for Fiscal 2020

July 10, 2020

July 10, 2020



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1 Introduction

This BC Hydro annual report to the British Columbia Utilities Commission (**BCUC or Commission**) on Demand-Side Management (**DSM**) activities provides information on DSM expenditures, electricity savings, plan performance and mitigation measures for the 2020 fiscal year, which is the twelve months ending March 31, 2020. This annual report is filed in compliance with the following BCUC Directives:

- Directive 69 from the BCUC Decision on BC Hydro's Fiscal 2005 - Fiscal 2006 Revenue Requirements Application (**F05-F06 RRA**);
- Directive 16 from the BCUC Decision on BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan (**2006 IEP/LTAP**);
- Directives 36 and 38 from the BCUC Decision on BC Hydro's 2008 LTAP; and
- Directive 23 from the BCUC Decision on BC Hydro's Fiscal 2017 – Fiscal 2019 Revenue Requirements Application (**F17-F19 RRA**).

Directive 69 of the F05-F06 RRA Decision directed BC Hydro “to provide information to the BCUC for on-going review of Power Smart performance through:

- Executive Summaries of milestone evaluation reports and full final evaluation reports for each program;
- Semi-annual reports on DSM activities which, amongst others, will include:
 - ▶ detailed breakdown of OMA expenses related to support activities carried out within the Power Smart group and in other departments that support the Power Smart organization;
 - ▶ detailed description of the functions of portfolio level costs and how these costs are allocated to programs;
 - ▶ summaries of the overall performance of Power Smart with reference to program objectives; and



- ▶ variances of fiscal year budgeted and actual deferred capital expenditures and explanation of variances.”

Directive 16 of the 2006 IEP/LTAP Decision directed BC Hydro “to continue to file reports on DSM performance as described in Directive 69 of the F05/F06 RRA Decision included in Order No. G-96-04 and to file its Semi Annual Demand-Side Management Reports in the same format as the June 2005 Report with the following enhancements:

Provide annual and cumulative totals since program inception;

- (i) Express these values on a per unit basis; and
- (ii) Provide the benefit to cost ratios for the three DSM tests.”

Directive 36 of the 2006 IEP/LTAP Decision directed BC Hydro to switch from semi-annual to annual DSM performance reports. Directive 38 from the same Decision directed BC Hydro to include in these reports:

“metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective.”

Directive 23 of the F17-F19 RRA Decision directs BC Hydro to “include a line item in BC Hydro’s Annual Report on DSM Activities to reflect the NIA activities that are tracked separately.”

BC Hydro files its evaluation reports pursuant to Directive 69 of the F05-F06 RRA Decision separately.

This annual report addresses the balance of Directives 69 and 16, as well as Directives 36 and 38 of the 2006 IEP/LTAP Decision and Directive 23 of the F17-F19 RRA Decision.



2 Expenditures and Electricity Savings for Fiscal 2020

BC Hydro's DSM expenditures¹ in fiscal 2020 totalled \$78.5 million, while new incremental DSM electricity savings totalled 722 GWh/year. Expenditures were \$12.4 million or 14 per cent below the Fiscal 2020 DSM Plan presented in BC Hydro's F20-F21 RRA. Overall, new incremental electricity savings as shown in [Table 1](#) were 22 GWh/year or 3 per cent above the DSM Plan.

[Table 1](#) presents planned and actual DSM expenditures and new incremental electricity savings in fiscal 2020.

¹ Comprising all DSM-related deferred operating expenditures. DSM operating expenditures are presented in [Table 6](#) of this report.

July 10, 2020



Table 1 Expenditures and New Incremental Electricity Savings for Fiscal 2020*

	Expenditures ¹				New Incremental Electricity Savings			
	Plan ² \$ 000	Actual \$ 000	Variance \$ 000	%	Plan ² GWh/yr	Actual ³ GWh/yr	Variance GWh/yr	%
Rate Structures								
Residential Inclining Block Rate	-	-	-	-	-	-	-	-
General Service Rate	-	-	-	-	-	-	-	-
Transmission Service Rate	452	294	(158)	(35%)	117	117	0	0%
Total Rate Structures	452	294	(158)	(35%)	117	117	0	0%
DSM Programs								
<u>Residential Sector</u>								
Low Income	5,819	5,165	(654)	(11%)	9	9	0	3%
Non Integrated Areas	1,208	920	(288)	(24%)	0.5	0.1	(0.3)	(69%)
Retail	2,120	2,392	272	13%	6	7	2	33%
Home Renovation Rebate	4,249	4,791	542	13%	8	9	1	12%
<u>Residential Energy Management Activities</u>	4,959	4,664	(295)	(6%)	13	19	6	42%
<i>Residential Sector Total</i>	18,354	17,932	(422)	(2%)	36	44	8	23%
<u>Commercial Sector</u>								
LEM-C	9,027	9,078	51	1%	51	48	(2)	(5%)
New Construction	3,676	3,296	(379)	(10%)	8	9	1	11%
<u>Commercial Energy Management Activities</u>	6,208	6,077	(130)	(2%)	n/a	n/a	n/a	n/a
<i>Commercial Sector Total</i>	18,910	18,452	(458)	(2%)	59	58	(1)	(2%)
<u>Industrial Sector</u>								
LEM-I	18,275	11,321	(6,954)	(38%)	132	129	(3)	(2%)
Thermo-Mechanical Pulp	-	-	-	-	-	-	-	-
<u>Industrial Energy Management Activities</u>	8,198	6,666	(1,532)	(19%)	n/a	n/a	n/a	n/a
<i>Industrial Sector Total</i>	26,474	17,987	(8,486)	(32%)	132	129	(3)	(2%)
Total Programs	63,738	54,371	(9,367)	(15%)	227	231	4	2%
Supporting Initiatives								
Public Awareness	7,423	7,328	(95)	(1%)	-	-	-	-
<u>Indirect and Portfolio Enabling</u>	7,133	6,851	(283)	(4%)	-	-	-	-
Supporting Initiatives Total	14,557	14,179	(378)	(3%)	-	-	-	-
Total Programs, Rates & Supporting Initiatives	78,747	68,844	(9,902)	(13%)	345	349	4	1%
Codes and Standards	5,185	5,246	61	1%	356	373	18	5%
Capacity Focused DSM	6,884	4,371	(2,513)	(37%)	-	-	-	-
PORTFOLIO TOTAL	90,816	78,462	(12,354)	(14%)	700	722	22	3%

* Numbers may not add due to rounding.

Notes:

¹ Including all DSM-related deferred operating expenditures.

² Plan figures are from BC Hydro's F20-F21 RRA, Appendix X.

³ Reported savings from codes and standards and residential inclining block and transmission service rate structures are based on planned estimates as well as evaluated results.

Report on Demand-Side Management Activities for Fiscal 2020

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The following provides explanations of the variances between planned and actual expenditures and savings shown in [Table 1](#) above:

<u>Rate Structures</u>	
Transmission Service Rate	Expenditures were below plan due to planned rate design activities to explore potential changes to RS 1823 being delayed. Electricity savings were on plan.
<u>DSM Programs</u>	
Residential Sector	
Low Income	Expenditures were below plan due to: - the development of a heap pump trial offer requiring more time than planned, resulting in the launch of the trial being shifted to fiscal 2021. - some activities within the Indigenous Communities Conservation program offer (in the integrated system) taking longer than planned, and thus shifting to fiscal 2021². Electricity savings were approximately on plan.
Non Integrated Areas	Expenditures and savings were below plan due to some activities within the Indigenous Communities Conservation program offer taking longer than planned to implement and thus shifting to fiscal 2021. Refer to section 3 on Non Integrated Area Activity for further detail.
Retail	Expenditures and electricity savings were above plan due to higher than expected participation in our new online smart thermostat offering.
Home Renovation Rebate	Expenditures and electricity savings were above plan due to higher than expected participation, particularly with heat pumps.
Residential Energy Management Activities	Expenditures were approximately on plan. Electricity savings were above plan due to higher than projected participation in energy reduction challenges as well as higher use of the Energy Visualization Portlet.
Commercial Sector	
LEM-C	Expenditures and electricity savings were approximately on plan.
New Construction	Expenditures were below plan due to the customer deferral of a project to fiscal 2021. Electricity savings were above plan due to updated assumptions from a recently approved program evaluation report.
Commercial Energy Management Activities	Expenditures were approximately on plan.
Industrial Sector	
LEM-I	Expenditures were below plan due to fewer Industrial customers advancing large incentive projects and energy studies than planned. Electricity savings were approximately on plan due to strategic energy management activity enabling additional energy savings at a lower cost.
Thermo-Mechanical Pulping	No expenditures or electricity savings were planned.
Industrial Energy Management Activities	Expenditures were below plan due to a number of energy manager positions becoming vacant, and the time required for customers to fill the vacancies.

² The Indigenous Communities Conservation program offer is available to communities in both the integrated system and the non-integrated areas. Refer to section [3](#) on the Non-Integrated Area Activity for more details on activities that took longer than planned.



Total Programs	Expenditures were below plan primarily due to fewer Industrial customers advancing large incentive projects and energy studies than planned. Electricity savings were approximately on plan.
Supporting Initiatives	
Public Awareness	Expenditures were approximately on plan.
Indirect and Portfolio Enabling	Expenditures were approximately on plan.
Codes and Standards	Expenditures and electricity savings were approximately on plan.
Capacity Focused DSM	Expenditures were below plan due to pilot project initiatives shifting out into future fiscal years, coming in with lower costs than budgeted, or being cancelled.
Portfolio Total	Expenditures were below plan primarily due to fewer Industrial customers advancing large incentive projects and energy studies than planned as well as Capacity Focused Demand-Side Management pilot project initiatives shifting out into future fiscal years, coming in with lower costs than budgeted, or being cancelled. Electricity savings were approximately on plan.

3 Non-Integrated Area Activity

BC Hydro's fiscal 2020 DSM expenditures, electricity savings and cost effectiveness results for the Non Integrated Areas program are shown as a line item within [Table 1](#) through [Table 5](#) and [Table 7](#) to [Table 8](#), along with all other programs.

Non-Integrated Area (NIA) activity in fiscal 2020 included the launch of new program offers for Indigenous communities, residential and commercial customers to support energy upgrades in homes and buildings. New program offers include:

- Indigenous Communities Conservation Program Offer:
 - ▶ Free energy saving products, salary support and installation training to conduct upgrades such as energy efficient lighting, high performance faucets and showerheads, and basic draft proofing.
 - ▶ Training to complete advanced energy upgrades to homes (e.g., insulation and air sealing, ventilation, heat pumps) and rebates to support the cost of those upgrades.
- Higher rebates for NIA residential customers through Home Renovation Rebates.
- Higher incentives for NIA commercial customers through Business Energy Savings Incentives.



BC Hydro's Low Income Program, including Energy Savings Kits and the Energy Conservation Assistance Program, continue to be available to NIA customers. Starting in fiscal 2020, NIA participants in these program offers were funded through the NIA program.

In addition, BC Hydro supported various capacity building activities with NIA Indigenous communities including energy-focused staff positions on Band Administrations, community energy planning and new construction policy development.

As seen in [Table 1](#), savings and expenditures in the Non-Integrated Areas program were below plan for Fiscal 2020. Expenditures were closer to plan than energy savings as a result of the capacity building activities (components of the program which do not directly generate energy savings) tracking closer to plan than the components that generate energy savings (implementation of home energy upgrade projects). For example, capacity building activities planned and undertaken in Fiscal 2020 involved support for staff positions in NIA Indigenous communities, training, planning, and analysis. While these activities do not generate savings in the short term, they are critical activities which form the foundation of the program and will enable communities to advance DSM energy savings projects over time. With these foundational activities in place, participation is expected to ramp up to the scale where cost-effectiveness aligns more closely with planned levels.

For the components of the program that generate energy savings (home energy upgrade projects), it took longer than planned for participation to gain momentum. To assist with this, BC Hydro hired a Relationship Manager in June 2019, whose role is to foster relationships with Indigenous Communities and find and assist local champions. While this approach has now gained traction, few projects were ready for implementation in time for the summer 2019 construction period. However, based on signed agreements and interest from communities, we expect an increased volume of implementation projects in fiscal 2021. This will improve the cost-effectiveness of the overall program.

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4 Expenditures to Date

BC Hydro's DSM expenditures for fiscal 2020 totalled \$78.5 million. [Table 2](#) presents DSM expenditures from April 1, 2019 to March 31, 2020.

Table 2 Expenditures since Fiscal 2020*

	F2020 (\$ 000)	F2021 (\$ 000)	Total (\$ 000)
Rate Structures			
Residential Inclining Block Rate	-	-	-
General Service Rate	-	-	-
<u>Transmission Service Rate</u>	294	-	294
Total Rate Structures	294	-	294
DSM Programs			
<u>Residential Sector</u>			
Low Income	5,165	-	5,165
Non Integrated Areas	920	-	920
Retail	2,392	-	2,392
Home Renovation Rebate	4,791	-	4,791
<u>Residential Energy Management Activities</u>	4,664	-	4,664
<i>Residential Sector Total</i>	17,932	-	17,932
<u>Commercial Sector</u>			
LEM-C	9,078	-	9,078
New Construction	3,296	-	3,296
<u>Commercial Energy Management Activities</u>	6,077	-	6,077
<i>Commercial Sector Total</i>	18,452	-	18,452
<u>Industrial Sector</u>			
LEM-I	11,321	-	11,321
Thermo-Mechanical Pulp	-	-	-
<u>Industrial Energy Management Activities</u>	6,666	-	6,666
<i>Industrial Sector Total</i>	17,987	-	17,987
Total Programs	54,371	-	54,371
Supporting Initiatives			
Public Awareness	7,328	-	7,328
<u>Indirect and Portfolio Enabling</u>	6,851	-	6,851
Supporting Initiatives Total	14,179	-	14,179
Total Programs, Rates & Supporting Initiatives	68,844	-	68,844
Codes and Standards	5,246	-	5,246
Capacity Focused DSM	4,371	-	4,371
PORTFOLIO TOTAL	78,462	-	78,462

* Numbers may not add due to rounding.

July 10, 2020



BC Hydro's DSM electricity savings since fiscal 2020 totalled 722 GWh/year at March 31, 2020, which equates to 103 per cent of the planned savings of 700 GWh/year in the F20-F21 RRA. [Table 3](#) presents actual cumulative savings as a percentage of plan in fiscal 2020.

Table 3 Cumulative Electricity Savings: Fiscal 2020

Actual as a Percentage of Plan ¹	
Rate Structures	
Residential Inclining Block Rate	n/a
General Service Rate	n/a
<u>Transmission Service Rate</u>	100%
Total Rate Structures	100%
DSM Programs	
<u>Residential Sector</u>	
Low Income	103%
Non Integrated Areas	31%
Retail	133%
Home Renovation Rebate	112%
<u>Residential Energy Management Activities</u>	142%
<i>Residential Sector Total</i>	123%
<u>Commercial Sector</u>	
LEM-C	95%
New Construction	111%
<u>Commercial Energy Management Activities</u>	n/a
<i>Commercial Sector Total</i>	98%
<u>Industrial Sector</u>	
LEM-I	98%
Thermo-Mechanical Pulp	n/a
<u>Industrial Energy Management Activities</u>	n/a
<i>Industrial Sector Total</i>	98%
Total Programs	102%
Codes and Standards	105%
Capacity Focused DSM	n/a
PORTFOLIO TOTAL	103%

Notes:

¹ Reported savings for codes and standards and rates structures are based on planned estimates as well as evaluated results.

July 10, 2020



The cumulative portfolio DSM electricity savings from April 1, 2019 through March 31, 2020 have been achieved at an average net levelized utility cost of \$25 per MWh. [Table 4](#) presents net levelized utility cost that is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings. A negative net levelized utility cost means that the subtracted capacity benefits exceed gross utility costs.

Table 4 Utility Cost of Electricity Savings: Fiscal 2020

	Net Levelized Utility Cost (\$/MWh)
Rate Structures	
Residential Inclining Block Rate	n/a
General Service Rate	n/a
<u>Transmission Service Rate</u>	-6
Total Rate Structures	-6
DSM Programs	
<u>Residential Sector</u>	
Low Income	22
Non Integrated Areas	609
Retail	2
Home Renovation Rebate	-2
Residential Sector Total	9
<u>Commercial Sector</u>	
LEM-C	11
New Construction	13
Commercial Sector Total	12
<u>Industrial Sector</u>	
LEM-I	8
Thermo-Mechanical Pulp	n/a
Industrial Sector Total	8
Total Programs	9
Energy Management Activities	n/a
Supporting Initiatives ¹	n/a
Codes & Standards	n/a
Portfolio Total²	25

Notes:

- 1 Supporting initiatives costs have not been allocated to programs. Refer to section 6 for net levelized utility cost with supporting initiative costs allocated to programs.
- 2 Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations because this initiative is still in the trial and pilot project stage and therefore the associated benefits have not yet been quantified.

[Table 5](#) presents benefit cost-ratios of actual DSM electricity savings achieved from April 1, 2019 through March 31, 2020.

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**Table 5 Benefit Cost Ratios of Electricity Savings:
Fiscal 2020**

	Benefit Cost Ratios ¹			
	LRMC (\$105 per MWh)			Market Price (\$30 per MWh)
	Modified Total Resource Cost Test ²	Total Resource Cost Test excluding NEBs	Ratepayer Impact Measure Test ³	Utility Cost Test
Rate Structures				
Residential Inclining Block Rate	n/a	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a	n/a
Transmission Service Rate	<u>4.7</u>	<u>4.7</u>	<u>1.0</u>	<u>23.2</u>
Total Rate Structures	4.7	4.7	1.0	23.2
DSM Programs				
<u>Residential Sector</u>				
Low Income ⁴	4.5	4.7	0.9	1.2
Non Integrated Areas ⁵	0.6	0.6	0.4	0.5
Retail	3.7	3.8	1.1	2.1
Home Renovation Rebate	<u>1.8</u>	<u>1.4</u>	<u>0.9</u>	<u>2.0</u>
<i>Residential Sector Total</i>	2.5	2.2	0.9	1.6
<u>Commercial Sector</u>				
LEM-C	3.4	2.1	1.1	1.8
New Construction	<u>1.8</u>	<u>1.5</u>	<u>1.1</u>	<u>1.7</u>
<i>Commercial Sector Total</i>	2.9	1.9	1.1	1.8
<u>Industrial Sector</u>				
LEM-I	5.3	3.8	1.1	2.2
Thermo-Mechanical Pulp	<u>n/a</u>	<u>n/a</u>	<u>n/a</u>	<u>n/a</u>
<i>Industrial Sector Total</i>	5.3	3.8	1.1	2.2
Total Programs	3.4	2.5	1.1	1.8
Energy Management Activities	n/a	n/a	n/a	n/a
Supporting Initiatives ⁶	n/a	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a	n/a
Portfolio Total⁷	2.5	2.0	0.9	1.1

Notes:

- ¹ To align with BC Hydro's F20-F21 RRA, this report uses a long-run marginal cost (LRMC) of \$105 per MWh. As described in BC Hydro's F20-F21 RRA, Chapter 10, this value is based on an outdated assessment of greenfield wind projects, including BC Hydro's cost to integrate and deliver energy to the load centre (Lower Mainland). BC Hydro plans to update the LRMC in the next IRP. Internal decisions on demand-side measures are based on the Utility Cost Test at market price and not on the LRMC.
- ² In accordance with the DSM Regulation, the avoided cost of natural gas is valued at BC Hydro's LRMC of acquiring electricity generated from clean or renewable resources in B.C. converted to \$/gigajoule (GJ) in all time periods. Non-energy benefits in the DSM Regulation are valued at 15 per cent of the energy and capacity benefits of electricity and natural gas, or as quantified by the Utility.
- ³ While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost-effectiveness of a demand-side measure, this benefit-cost ratio is included in the table to comply with Directive 42 from the BCUC decision on BC Hydro's 2008 LTAP.
- ⁴ The Total Resource Cost Test benefit-cost ratios for the Low Income Program include a 40 per cent adder to program benefits, in accordance with the DSM Regulation.
- ⁵ Avoided costs in all cost tests are based on NIA generation costs.
- ⁶ Supporting initiatives costs have not been allocated to programs. Refer to section 6 for benefit cost ratios with supporting initiative costs allocated to programs.
- ⁷ Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations because this initiative is still in the trial and pilot project stage and therefore the associated benefits have not yet been quantified.

July 10, 2020



Based on the experience gathered over the past few years through initiative tracking, the following are mitigation measures that have been undertaken or are planned for the future to address areas where cumulative energy savings are below plan. For some initiatives where cumulative energy savings are on or above plan, the table includes planned actions to ensure performance is maintained.

Rate Structures	
Industrial Transmission	Cumulative electricity savings in fiscal 2020 were on plan.
DSM Programs	
Residential Sector	
Low Income	Cumulative electricity savings in fiscal 2020 were approximately on plan. Promotional activities have broadened to include social media and online advertising to further raise program awareness.
Non Integrated Area	Cumulative electricity savings in fiscal 2020 were below plan. The addition of a Relationship Manager to foster relationships with Indigenous Communities and find and assist local champions has gained traction and is expected to help keep identified project opportunities progressing to completion in fiscal 2021. This will improve cost effectiveness.
Retail	Cumulative electricity savings in fiscal 2020 were above plan. The program is exploring more online sales through partnerships and means of increasing online education on efficient products.
Home Renovation Rebate	Cumulative electricity savings in fiscal 2020 were above plan. The program continues to drive contractor engagement and development of education to ensure installation best practice through Program Registered Contractors.
Residential Energy Management Activities	Cumulative electricity savings were above plan. A mobile device friendly version of the Energy Visualization Portlet was launched and a mobile device friendly version of Team Power Smart will launch in early fiscal 2021 to further align with customer migration away from desktop devices.
Commercial Sector	
LEM-C	Cumulative electricity savings in fiscal 2020 were approximately on plan. Going forward, the program will continue to make adjustments based on market feedback, working with large key account customers to remove their barriers to adoption, providing energy advisors to assist small and medium businesses, and reviewing the list of eligible energy conservation measures.
New Construction	Cumulative electricity savings in fiscal 2020 were above plan. The program is ramping down.
Industrial Sector	
LEM-I	Cumulative savings in fiscal 2020 were approximately on plan. The program will continue to leverage strategic energy management activities and the program offer will be adjusted to stimulate participation in the incentive and study offers.
Thermo-Mechanical Pulping	The Thermo Mechanical Pulp program was implemented pursuant to Government direction, and was subject to specific criteria and timelines. The deadline for project submission has passed and no further projects are planned through this program.
Capacity Focused DSM	No capacity savings in fiscal 2020 as these are pilot initiatives.



5 Operating Expenditures for Fiscal 2020

BC Hydro's DSM operating expenditures in fiscal 2020 totalled \$569,234.³ [Table 6](#) presents DSM operating expenditures in fiscal 2020.

Table 6 Operating Expenditures for Fiscal 2020

	(\$000)
Labour	504
Consultants/Contractors/Temp Labour	4
Other	61
Total	569

6 Allocation of Supporting Initiatives Costs to Programs

Directive 61 from the BCUC decision on the F05-F06 RRA requires supporting initiatives costs to be allocated to programs. In its Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, BC Hydro has requested that Directive 61 be rescinded, as costs should only be attributed to programs if they are solely connected to a specific program. As described in the application, this approach is more consistent with the Demand-Side Measures Regulation and industry practice, and also facilitates more appropriate marginal cost decision making when designing a DSM portfolio. Accordingly, [Table 4](#) and [Table 5](#) do not allocate supporting initiatives to programs.

Since the BCUC has not yet made a decision on whether to rescind Directive 61, we are also providing levelized costs and benefit cost ratios with supporting initiatives costs allocated to programs in [Table 7](#) and [Table 8](#) below.

Fiscal 2025 has been used as the year for energy savings allocation. As an example, if rate structures and programs are forecast to save roughly 700 GWh/year in fiscal 2025, a program that is forecast to save 7 GWh/year in fiscal 2025 represents 1 per cent of the total. In turn, 1 per cent of supporting initiatives costs would be allocated to that program in each year when calculating the program's levelized cost or benefit-cost ratio.

³ DSM operating expenditures are not included in earlier tables.

July 10, 2020



Table 7 **Utility Cost of Electricity Savings with
Supporting Initiative Costs Allocated to
Programs: Fiscal 2020**

	Net Levelized Utility Cost (\$/MWh)
Rate Structures	
Residential Inclining Block Rate	n/a
General Service Rate	n/a
<u>Transmission Service Rate</u>	<u>0</u>
Total Rate Structures	0
DSM Programs	
<u>Residential Sector</u>	
Low Income	32
Non Integrated Areas	618
Retail	12
Home Renovation Rebate	<u>6</u>
<i>Residential Sector Total</i>	19
<u>Commercial Sector</u>	
LEM-C	21
New Construction	<u>23</u>
<i>Commercial Sector Total</i>	21
<u>Industrial Sector</u>	
LEM-I	15
Thermo-Mechanical Pulp	<u>n/a</u>
<i>Industrial Sector Total</i>	15
Total Programs	18
Energy Management Activities	n/a
Supporting Initiatives ¹	n/a
Codes & Standards	n/a
Portfolio Total²	25

Notes:

- 1 Supporting initiatives costs have been allocated to programs.
- 2 Energy management activities and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations because this initiative is still in the trial and pilot project stage and therefore the associated benefits have not yet been quantified.

July 10, 2020



Table 8 **Benefit Cost Ratios of Electricity Savings
with Supporting Initiative Costs Allocated to
Programs: Fiscal 2020**

	Benefit Cost Ratios ¹			
	LRMC (\$105 per MWh)			Market Price (\$30 per MWh)
	Modified Total Resource Cost Test ²	Total Resource Cost Test excluding NEBs	Ratepayer Impact Measure Test ³	Utility Cost Test
Rate Structures				
Residential Inclining Block Rate	n/a	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a	n/a
Transmission Service Rate	3.8	3.8	0.9	4.7
Total Rate Structures	3.8	3.8	0.9	4.7
DSM Programs				
<u>Residential Sector</u>				
Low Income ⁴	3.6	3.7	0.8	1.0
Non Integrated Areas ⁵	0.6	0.6	0.4	0.5
Retail	2.8	2.9	1.0	1.5
Home Renovation Rebate	1.7	1.3	0.9	1.7
<i>Residential Sector Total</i>	2.2	2.0	0.9	1.3
<u>Commercial Sector</u>				
LEM-C	2.9	1.8	1.0	1.3
New Construction	1.7	1.3	1.0	1.2
<i>Commercial Sector Total</i>	2.5	1.7	1.0	1.3
<u>Industrial Sector</u>				
LEM-I	4.3	3.0	1.1	1.5
Thermo-Mechanical Pulp	n/a	n/a	n/a	n/a
<i>Industrial Sector Total</i>	4.3	3.0	1.1	1.5
Total Programs	2.9	2.1	1.0	1.4
Energy Management Activities	n/a	n/a	n/a	n/a
Supporting Initiatives ⁶	n/a	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a	n/a
Portfolio Total⁷	2.5	2.0	0.9	1.1

Notes:

- ¹ To align with BC Hydro's F20-F21 RRA, this report uses a long-run marginal cost (LRMC) of \$105 per MWh. As described in BC Hydro's F20-F21 RRA, Chapter 10, this value is based on an outdated assessment of greenfield wind projects, including BC Hydro's cost to integrate and deliver energy to the load centre (Lower Mainland). BC Hydro plans to update its LRMC in the next IRP. Internal decisions on demand-side measures are based on the Utility Cost Test at market price and not on the LRMC.
- ² In accordance with the DSM Regulation, the avoided cost of natural gas is valued at BC Hydro's LRMC of acquiring electricity generated from clean or renewable resources in B.C. converted to \$/gigajoule (GJ) in all time periods. Non-energy benefits in the DSM Regulation are valued at 15 per cent of the energy and capacity benefits of electricity and natural gas or as quantified by the Utility.
- ³ While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost-effectiveness of a demand-side measure, this benefit-cost ratio is included in the table to comply with Directive 42 from the BCUC decision on BC Hydro's 2008 LTAP.
- ⁴ The Total Resource Cost Test benefit-cost ratios for the Low Income Program include a 40 per cent adder to program benefits, in accordance with the DSM Regulation.
- ⁵ Avoided costs for all cost tests are based on NIA generation costs.
- ⁶ Supporting initiatives costs have been allocated to programs.
- ⁷ Energy management activities and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations because this initiative is still in the trial and pilot project stage and therefore the associated benefits have not yet been quantified.

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix X GGRR Annual Report

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June 29, 2020

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British Columbia Utilities Commission
 GHG Reduction (Clean Energy)
 Regulation Reporting

Email: commission.secretary@bcuc.com

**RE: Ministry of Energy, Mines and Petroleum Resources (MEMPR or Ministry)
 British Columbia Hydro and Power Authority (BC Hydro)
 Greenhouse Gas Reduction (Clean Energy) Regulation Reporting
 Fiscal 2020 Annual Report**

BC Hydro writes to submit the Business Information and Declaration (Attachment 1), the Fiscal 2020 Greenhouse Gas Reduction Regulation (**GGRR**) Annual Report (**Report**) (Attachment 2) and LCE Program Results in an excel format (Attachment 3). The Report includes results for the period from April 1, 2019 to March 31, 2020 (**Fiscal 2020**) for BC Hydro's prescribed undertakings as defined in section 4 of the GGRR.

Under section 18 of the *Clean Energy Act*, a public utility implementing prescribed undertakings defined in the GGRR, must submit to the MEMPR a report respecting the prescribed undertaking. Specifically, section 18(5) states that "a report to be submitted under section (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies."

In April 2018, Ministry staff issued the GGRR reporting requirements. The reporting requirements state that an annual report is due by June 30 of each year and prescribed the form of the report.

BC Hydro is redacting customer-specific information in this version of the Report. An un-redacted version of the Report is being filed with the Ministry and BCUC only under separate cover.

June 29, 2020

GHG Reduction (Clean Energy) Regulation Reporting Director,
Communities and Transportation
Electricity and Alternative Energy Division
Ministry of Energy, Mines and Petroleum Resources

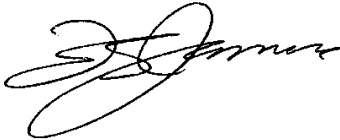
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Regulation Reporting

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting
CONFIDENTIAL Fiscal 2019 Annual Report

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For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

cu/ma

Enclosures (3)

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 1 Business Information and Declaration

Business Information and Declaration

Full Legal and Operating Name	Address Including Postal Code and Email	Telephone
British Columbia Hydro and Power Authority	333 Dunsmuir Street, Vancouver BC V6B 5R3	604-623-4046
Reporting Period:	April 1, 2019 to March 31, 2020 (Fiscal 2020)	
I understand that the information in this report is collected for the purposes of administering the Greenhouse Gas Reduction (Clean Energy) Regulation under the authority of the <i>Clean Energy Act</i> and section 26 of the <i>Freedom of Information and Protection of Privacy Act</i>. I certify that records evidencing each matter reported under the Greenhouse Gas Reduction (Clean Energy) Regulation (the Regulation) Reporting Requirements are available on request. I certify that a record evidencing my authority to submit this report on behalf of the public utility is available on request. I certify that the information in this report is true and complete to the best of my knowledge and I understand that I may be required to provide to the Ministry of Energy, Mines and Petroleum Resources or the Commission records evidencing the truth of that information.		
Signature of Authorized Signing Authority	Name and Title of Authorized Signing Authority (please print)	Date Signed YYYY/MM/DD
	Fred James Chief Regulatory Officer	June 29, 2020



Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 2

Fiscal 2020 Annual Report No. 3

April 2019 to March 2020

PUBLIC

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1 Executive Summary

This is BC Hydro's third annual report regarding its programs and projects that are "prescribed undertakings" as defined in the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) for the purposes of section 18 of the *Clean Energy Act* (**CEA**). It is provided in response to the December 2018 "British Columbia Greenhouse Gas Reduction (Clean Energy) Regulation Reporting Requirements" (**Reporting Requirements**) provided to BC Hydro by the Ministry of Energy, Mines and Petroleum Resources. The report covers the annual period from April 1, 2019 to March 31, 2020 (**Fiscal 2020**).

In Fiscal 2020, BC Hydro undertook the activities and expenditures listed below. BC Hydro collectively refers to these activities or expenditures that fall within a class of undertakings prescribed under sections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR as Low Carbon Electrification (**LCE**) Programs. The expenditure for the LCE Programs in Fiscal 2020 is approximately \$16.9 million.

- BC Hydro provided supporting resources¹ for six new LCE studies and two new LCE projects which are prescribed undertakings under section 4(3)(a) of the GGRR, further described in section [4.2](#) below;
- BC Hydro undertook public awareness campaign activities under section 4(3)(a) of the GGRR, including a rebate 'Top-up' promotion in conjunction with the Province of B.C.'s (**Province**) 'Go Electric BC' electric vehicle (**EV**) charger rebate program;
- BC Hydro provided supporting resources to seven studies that advance research related to new applications of technologies that have not yet been proven or adopted in BC, and to projects with specific customers researching

¹ Supporting resources can include: funding provided by BC Hydro to enable studies, research, pilots, public awareness campaigns, projects, and enabling the development of standards.

technology applications where the learnings will inform future BC Hydro programs and customer opportunities. These seven studies are undertakings prescribed under section 4(3)(c) of the GGRR; and

- BC Hydro provided supporting resources to enable the development of standards respecting technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions. These projects are undertakings prescribed under section 4(3)(d) of the GGRR.

BC Hydro also made significant progress on the Peace Region Electricity Supply (**PRES**) Project, which is an undertaking under section 4(2) of the GGRR. In Fiscal 2020, actual expenditure on the PRES Project was \$83.0 million, with a cumulative cost of \$152.9 million as at the end of the reporting period. It is premature to report any avoided greenhouse gas emissions for the PRES Project as it is not yet in-service. Total expenditures of \$1.7 million were incurred in Fiscal 2020 with respect to a [REDACTED] generation agreement BC Hydro entered into with [REDACTED] (hereinafter referred to as **Company X**) to ensure the provision of reliable electricity service from the transmission system [REDACTED]. This is also an undertaking under section 4(2) of the GGRR.

2 The GGRR and Cost Recovery

Section 18(1) of the CEA empowers the Lieutenant Governor in Council to prescribe, by regulation, classes of undertakings for the purpose of reducing greenhouse gas (**GHG**) emissions. Public utilities that choose to engage in undertakings that are within one or more prescribed class of undertaking are assured of being able to recover the costs of the undertaking in their rates, and may not be prevented by the British Columbia Utilities Commission from engaging in the undertaking. The GGRR was first issued in 2012, and amended in 2017 to include eight new classes of

electrification undertakings. Together, CEA section 18 and the GGRR provide one of the statutory pillars of the Province's GHG emission reduction policy.

The eight new classes of electrification undertaking prescribed by GGRR section 4 can be divided into two broad categories: (i) those that are program based, similar to BC Hydro's demand-side management programs;² and (ii) those that are infrastructure based.³ BC Hydro refers to all the prescribed undertakings it carries out as Low Carbon Electrification or LCE activities, and further refers to its undertakings that fall within one of the classes in the former category as LCE Programs, and to its undertakings that fall within one of the classes in the latter category as LCE Infrastructure Projects.

This nomenclature corresponds to the "Electrification Programs" referred to in subsection 6.8 of the GGRR Reporting Requirements, and "Transmission, Distribution and Generation" referred to in subsection 6.9 of the GGRR Reporting Requirements, respectively.

One of the legal consequences of the public utility program or project being a "prescribed undertaking" is that the public utility is entitled to recover the costs of the program or project in its rates. That legal consequence is meaningful only if the costs associated with particular programs and projects that are prescribed undertakings can be identified and thus are accounted for by the public utility.⁴ Accordingly, the prescribed undertakings described in this Fiscal 2020 GGRR Annual Report are those programs and projects with recorded costs in Fiscal 2020.

² Being the classes of undertaking prescribed by subsections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR. Under section 4(3)(c) and (d) of the GGRR, undertakings can be both projects or programs. For simplicity, BC Hydro may refer to projects under these sections as programs as well or use projects/program interchangeably.

³ Being the classes of undertaking prescribed by subsections 4(2) and 4(3)(e) of the GGRR.

⁴ BC Hydro notes that the costs it incurs with regard to its LCE programs are all deferred to the DSM Regulatory Account, pursuant to Order in Council No. 100, issued March 1, 2017. Generally, the costs it incurs in regard to its LCE Infrastructure Projects are capitalized.

3 State of the Market and Program Planning

3.1 Background

In December 2018, the Province launched the CleanBC Plan, which set out a pathway to enable the Province to meet its 2030 GHG emission targets. The CleanBC Plan calls for BC Hydro to continue to make investments in our transmission system to make it easier for large industrial operations to access clean electricity.

The February 2019 Minister's Mandate Letter to BC Hydro included an expectation for BC Hydro to continue to provide leadership in advancing the Province's climate action strategies, including through electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, oil and gas, and other sectors.

In July 2019, the Terms of Reference for Phase 2 of the Comprehensive Review (**Phase 2 Review**) were released by the Province. The objective of the Phase 2 Review is to develop recommendations that will strategically position BC Hydro for long-term success, while meeting the Province's climate goals, keeping rates affordable for British Columbians, furthering reconciliation with Indigenous Nations, and supporting quality economic development. The actions taken as part of the Phase 2 Review will support the Province's CleanBC plan, including to expand the electrification of our growing economy over the coming decades.

3.2 State of the Market Discussion

This section presents an overview of the LCE market with respect to BC Hydro's activities in Fiscal 2020. Detailed information on the LCE Programs and LCE Infrastructure Projects is set out in section [4](#) and section [5](#), respectively below.

Beginning in fiscal year ending March 31, 2018, BC Hydro moved forward with eight projects, referred to as Initial LCE Projects, to assess and support immediate low

carbon electrification opportunities among our customers. These projects are within one (or more) class of undertakings defined in subsections 4(3)(a) and 4(3)(c).

These Initial LCE Projects also

- helped us gain a greater understanding of the technology, market, and barriers that customers and BC Hydro would face when developing low carbon electrification options; and
- provided BC Hydro with the ability to act early and capture time sensitive opportunities that could help inform the development of a broader low carbon electrification plan.

The Initial LCE Projects introduced in the GGRR Annual Report filed in July 2018 have been updated in subsequent reports as the expenditures were incurred. They are also included in [Table 5](#) within this report.

In fiscal year ending March 31, 2019 (**Fiscal 2019**), BC Hydro developed and advanced a new multi-year BC Hydro funded LCE program that was designed to work in coordination with the Province's programs and is generally referred to as the BC Hydro LCE Program. The BC Hydro LCE Program is further described in section [4](#).

BC Hydro is forecast to be in an energy surplus position for an extended period of time. During this surplus period, the LCE-driven incremental electricity sales will increase BC Hydro's revenues and can make rates lower than they otherwise would have been to the extent there is a positive differential between domestic electricity rates and forecast export prices. Such incremental electricity sales are also expected to reduce GHG emissions from what they otherwise would have been, thus having an environmental benefit.

Pursuant to the Reporting Requirements, a report by a Fairness Advisor must be provided on the competitiveness of any call process held during the reporting period.

Consistent with our DSM process, opportunities for LCE Programs are solicited broadly through BC Hydro's customer and community-facing employees and our existing commercial and industrial energy manager networks. BC Hydro confirms that in Fiscal 2020 it did not hold any call processes in regard to its LCE Programs or its LCE Infrastructure Projects and therefore no Fairness Advisor report is required.

3.3 Province of B.C. Programs

In Fiscal 2019, BC Hydro became responsible for delivering the CleanBC Better Buildings program (initially called EfficiencyBC) on behalf of the Province. The CleanBC Better Buildings is a program funded by provincial and federal governments that provides financial incentives to help households and businesses save energy and reduce GHG emissions by switching to high efficiency heating equipment and making building envelope improvements. BC Hydro is delivering the component of the CleanBC Better Buildings program that helps customers switch from fossil fuels to clean electricity.

In Fiscal 2020, BC Hydro became responsible for delivering the CleanBC 'Go Electric BC' EV charger rebate program. The program provides rebates toward the cost of the purchase and installation of eligible level 2 EV charging equipment, and supports multi-unit residential buildings (**MURB**) and workplaces seeking solutions for their EV charging needs. The CleanBC program influences what programs BC Hydro funds as it seeks to align with and complement the programs and projects funded by the Province through the CleanBC program. BC Hydro's programs that complement the CleanBC programs are discussed in section [4](#) below.

4 LCE Programs

4.1 Overview

In Fiscal 2020, BC Hydro spent approximately \$16.9 million on its LCE Programs, including expenditures for Initial LCE Projects⁵ and the BC Hydro LCE Program. Particularly, expenditures for two new projects, six new studies, and public awareness campaign activities, all undertaken in accordance with section 4(3)(a) of the GGRR. Additionally, expenditures were incurred for seven new studies undertaken under section 4(3)(c) of the GGRR. BC Hydro also incurred expenditures to enable the development of standards under section 4(3)(d) of the GGRR. These LCE undertakings listed above are discussed in section [4.2](#).

In Fiscal 2020, BC Hydro made new funding commitments of approximately \$1.1 million, but there are no expenditures for the projects associated with those commitments in the financial reporting for Fiscal 2020. As noted in the previous Annual Reports, all funding commitments that do not result in expenditures in Fiscal 2020 will not be included in this document and will be included in future GGRR reports in the fiscal year when the expenditures are incurred.

As discussed above, since Fiscal 2019, BC Hydro delivers the CleanBC Better Buildings program on behalf of the Province. To complement the Province's program, in Fiscal 2019, BC Hydro developed and advanced a new multi-year BC Hydro funded LCE Program which was designed to reach customers and to enable opportunities not covered by GHG emissions reduction programs funded by the Province or the federal government.⁶ BC Hydro approved expenditures of \$16.6 million for this multi-year program, focusing on opportunities in industrial process, transportation, and new construction. In Fiscal 2020, the Province working

⁵ The Fiscal 2020 expenditures referenced as Initial LCE projects include two projects classified under section 4(3)(a) and one study classified under section 4(3)(c). All other expenditures are referenced as BC Hydro LCE Program.

⁶ This multi-year program may sometimes be referred to as "BC Hydro LCE Program" to distinguish it from the programs funded by the Province.

in co-ordination with BC Hydro made a decision to direct a portion of the CleanBC funding to support the design and construction of new high-performance buildings that use high-efficiency electricity in place of fossil fuels in order to reduce GHG emissions. The introduction of the CleanBC funding prompted BC Hydro to re-consider the funding originally included within the multi-year BC Hydro LCE Program. BC Hydro was able to apply funds originally intended to support new construction opportunities to support additional energy management study and implementation opportunities for industrial and large commercial customers. As part of this multi-year program, in Fiscal 2020, BC Hydro undertook activities as prescribed undertakings falling under section 4(3)(a), section 4(3)(c), and section 4(3)(d) of the GGRR. These undertakings are discussed in section [4.2](#) below.

4.2 Fiscal 2020 LCE Programs

The projects and activities within the LCE Programs (i.e., classes of undertaking prescribed by subsections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR) that incurred expenditures in Fiscal 2020 are listed below. [Table 5](#) includes the LCE Program results for Fiscal 2020, and [Figure 1](#) and [Figure 2](#) show LCE Program activities and expenditures by geographic distribution and sector distribution, respectively.

Consistent with the reporting requirements, two larger, upstream natural gas projects have been described at a project level, while the remaining Fiscal 2020 activities are components of the BC Hydro LCE Program, and these activities have been aggregated and summarized at the program level.

- (i) [REDACTED] (Project 3 in [Table 5](#)): This project is interconnected to BC Hydro transmission line [REDACTED] in Northeastern B.C. It is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR. There are multiple project phases. The first

two phases achieved Facility Commercial Operation Date (**Facility COD**)⁷ in Fiscal 2019 and Fiscal 2020, respectively, pursuant to the terms of the LCE Incentive Agreement. Further project phases are expected to achieve Facility COD in subsequent fiscal years. The purpose of the supporting funds from BC Hydro is to assist Company X in the acquisition, installation, and use of equipment that will use BC Hydro's electricity instead of natural gas to power natural gas extraction, processing and production operations.

- (ii) [REDACTED] (**Project 4** in [Table 5](#)): BC Hydro also has an LCE Incentive Agreement for the [REDACTED] site. This project is interconnected to BC Hydro transmission line [REDACTED] in Northeastern B.C. There are multiple project phases. Similar to Project 3, this project is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR. Project 4 was energized in Fiscal 2019 and the first two phases achieved Facility COD in Fiscal 2020 in accordance with the LCE Incentive Agreement.
- (iii) The BC Hydro LCE Program: [Table 1](#) outlines the components of the BC Hydro LCE Program and the relevant subsections of the GGRR.

Table 1 Components of the BC Hydro LCE Program

Components	GGRR Subsection
Energy Management Studies and Incentives	4(3)(a), 4(3)(b)
Public Awareness Campaigns	4(3)(a), 4(3)(b)
Research and Pilots	4(3)(c)
Standards Enabler	4(3)(d)
Education & Training	4(3)(b)

An overview of activities in Fiscal 2020 for each of the components of the BC Hydro LCE Program is provided below.

⁷ Under the Incentive Agreement, Facility COD is required before an incentive fund payment can be made to the customer.

Energy Management Studies and Incentives: BC Hydro provided supporting resources to studies of low carbon electrification opportunities in the built environment, industrial process, and transportation sectors. [Table 2](#) provides descriptions. In Fiscal 2020, expenditures for Energy Management Studies and Incentives are reflected in the BC Hydro LCE Program, row 10 in [Table 5](#).

Table 2 Energy Management Studies and Incentives

Sector	Description	Location	Studies Completed	GGRR Subsection
Built Environment	There were three studies in the built environment sector completed in Fiscal 2020. Two of the three studies were for large commercial re-development sites in the Lower Mainland (North Vancouver and Burnaby). Each study investigated low carbon electrification district energy options which could be used in place of fossil fuel-based systems for providing space heating and domestic hot water. The two concluded studies are with customers for their consideration on further study or investment decisions. The third study was for a post-secondary institution located in the Lower Mainland. The study examined electrification opportunities for campus building retrofits as well as future construction. Recommendations from the study will feed into the customer's plan to meet Carbon Neutral Government ⁸ targets for public sector GHG reduction (50 per cent reduction from the 2007 baseline by 2030), while the post-secondary institution continues to grow. The recommendations are with the customer for presentation to a committee within the institution for review and direction.	Lower Mainland	3	4(3)(a)

⁸ The Carbon Neutral Government program is further described at the following link:
<https://www2.gov.bc.ca/gov/content/environment/climate-change/public-sector/carbon-neutral>.

Sector	Description	Location	Studies Completed	GGRR Subsection
Industrial Process	There were two studies in the industrial process sector completed at two separate industrial customer sites in Fiscal 2020. One of the studies examined options to utilize electric boilers to reduce or completely remove the use of natural gas-fired boilers in steam production. The study is complete and now with the customer for consideration on further study or investment decision. The other study examined options for the replacement of diesel-powered pumping systems used within mining operations with BC Hydro electricity powered pumps. This completed study enabled the customer to move forward with project implementation which is expected to be completed in Fiscal 2021.	Vancouver Island Sunshine Coast, North	2	4(3)(a)
Transportation	There was one study in the transportation sector completed in Fiscal 2020. This study provided an assessment of electric vehicle charging infrastructure that could address the charging requirements for fleet vehicle conversion as well as employee charging needs. The study is complete and with the customer for consideration on further study or investment decision.	Lower Mainland	1	4(3)(a)

Research and Pilot Projects and Studies: BC Hydro provided supporting resources to advance research and pilot projects and studies involving low carbon electrification opportunities in the built environment, industrial process, and transportation sectors. Projects and studies supported research, development, or application of a technology that was new or unique and had not been proven in or adopted in B.C., or provided information that may inform future BC Hydro programs and customer opportunities to use electricity instead of other sources of energy that produce more GHG emissions. [Table 3](#) below provides descriptions of the research and pilot projects and studies. In

Fiscal 2020, expenditures for Research and Pilot projects and studies are reflected in the BC Hydro LCE Program, row 9 and 11 in [Table 5](#).

Table 3 Research and Pilots

Sector	Description	Location	Studies Completed	GGRR Subsection
Built Environment	There were two projects completed in Fiscal 2020 which examined LCE technology options for the built environment. One project consisted of six individual buildings selected to represent a sampling of various building types, building code requirements, technologies, and studies the low carbon electrification opportunities that we may see come forward as implementation projects in these building types. The information gained from this project was used by BC Hydro and Province to inform the development of the CleanBC Better Buildings program. The focus of the second project was for the customer to have research completed on the potential of a five-year “building by building” retrofit approach, considering a number of technologies that could enable electrifying building systems instead of using other sources of energy that produce more greenhouse gas emissions. The project is complete and has facilitated the customer to advance a detailed feasibility study for campus wide heating system electrification.	Lower Mainland, Interior	2	4(3)(c)
Industrial Process	There was one industrial process research study completed at a customer site in Fiscal 2020. The study examined options for alternative fuel vehicles in place of diesel fueled vehicles for use in mining operations. The study provided a recommendation that the tethered electric vehicle could be feasible among the potential low carbon vehicle types analyzed and should progress to a detailed feasibility study. The recommendation is with the customer for their consideration on further study or investment decision.	Interior	1	4(3)(c)

Sector	Description	Location	Studies Completed	GGRR Subsection
Transportation	In Fiscal 2020, there were four studies which examined low carbon electrification technology options in the Transportation sector. Two of the four studies completed were for large sea port operations, and the outcome of each was the development of low carbon electrification road maps which assessed the individual port operations and identified electrification scenarios and technologies that could be implemented in the near and long term. The third study assessed options for the installation of battery electric yard tractors and the associated electric vehicle (EV) charging equipment and supporting electrical infrastructure at a Lower Mainland sea port to replace an existing fleet of diesel-powered yard tractors. A technical trial was recommended as the next step from this study and is being considered by the customer. The fourth study is a pilot project in the Lower Mainland, which studies the replacement of four diesel buses with four electric-battery buses and two charging stations. The two-year pilot was developed to evaluate the feasibility of technology using electric battery buses and charging stations on a broader basis. In September 2019, the first of four battery electric buses and two high-powered, standardized overhead charging systems began operation.	Lower Mainland, North	4	4(3)(c)

Public Awareness Campaign: In Fiscal 2020, as part of the multi-year BC Hydro LCE Program, BC Hydro continued public awareness efforts with respect to owning and using electric vehicles in B.C. The campaign ran from September 2019 to November 2019, and focused on raising awareness of electric vehicles as a clean, practical choice for British Columbians. The campaign also promoted the availability of EV home charging solutions and charger rebates. In co-ordination with the Province, the 'Go Electric BC' EV charger rebate 'Top-up' promotion was developed, and BC Hydro supported

customers with rebate ‘top-ups’ directed toward the cost of purchase and installation of eligible level 2 EV charging equipment for homeowners. In Fiscal 2020, expenditures for this public awareness campaign including the ‘Go Electric BC’ EV charger rebate ‘Top-up’ promotional program are included in the BC Hydro LCE Program, row 10 in [Table 5](#). The public awareness campaign program and ‘Go Electric BC’ EV charger rebate ‘Top-up’ promotional program are undertakings within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR.

Standards Enabler: BC Hydro has been working with local governments to support the development and implementation of policies, bylaws, and strategies for energy efficient buildings and local communities.

- ▶ Targeting transportation electrification, BC Hydro supported the development of electric vehicle and low carbon mobility planning and implementation in Township of Langley, City of Surrey, City of Kamloops, Capital Regional District, City of Vancouver, District of Saanich, and the Regional District of East Kootenays. A local government EV peer network was coordinated to advance adoption and implementation of EV-ready new construction requirements for residential buildings. These requirements have now been adopted by 17 local governments. This work has provided a template for the development of similar EV-ready new construction requirements for non-residential buildings (commercial, office, and institutional).
- ▶ Targeting the built environment, BC Hydro worked on a roadmap with local, provincial, and federal governments and industry partners to understand and remove barriers for heat pump adoption. This work included identification of policy, bylaw and compliance tools available to local governments to make it easier for private building owners to install heat pump within new and

existing buildings. Tools being explored include new construction requirements, siting guidelines, and bylaw requirements.

- For new construction, five local governments (City of Richmond, City of Surrey, City of New Westminster, City of Port Moody, City of Burnaby) have taken steps to encourage low carbon electrification by implementing measures relating to the Energy Step Code in Part 3 buildings⁹. In Fiscal 2020, the District of West Vancouver implemented measures to support low carbon electrification of the new construction of residential Part 9 buildings.¹⁰ Actions taken are shared through the BC Energy Step Code local government peer networks to encourage policy consistency.

Standards Enabler undertaking expenditures fall under section 4(3)(d) of the GGRR. In Fiscal 2020, expenditures for Standards Enabler undertakings are reflected in the BC Hydro LCE Program, row 12 in [Table 5](#). Ratepayer impacts and estimated GHG emission reductions respecting these undertakings are also shown in [Table 5](#) below.

4.3 Methodology and Verification Methods

Depending on individual projects or programs within the LCE Programs, there can be up to four distinct activities that BC Hydro may use to review and verify estimates of incremental electrical load and emission reductions arising from electrification. These are: (i) technical review; (ii) site inspection; (iii) measurement and verification; and (iv) evaluation. Results from each area may be used in project or program management to ensure that BC Hydro receives the expected benefits. BC Hydro will be selective in the use of these processes, and focus its efforts where warranted to improve the accuracy of estimates and reduce exposure to risk. This approach mirrors BC Hydro's current approach to demand-side management electricity

⁹ As classified within the BC Building Code, these are buildings that are at least four storeys and have a building area greater than 600 square metres.

¹⁰ As classified within the BC Building Code, these are buildings that are no more than three storeys and have a building area no more than 600 square metres.

savings, and provides estimates for both additional electricity demand and greenhouse-gas emission reductions.

The GHG emission reduction estimates are developed as part of the technical review for each project or program application and may be adjusted based on the outcome of site inspections and the electricity demand findings resulting from the measurement and verification activities.

The methodology BC Hydro has used to estimate GHG emission reductions involves developing engineering estimates of the amount of carbon-based fuel that will be offset by electricity, and quantifying the associated GHG emission reductions using the 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions. The calculation nets out the GHG emissions associated with BC Hydro's electricity, which are also quantified using the 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions.

BC Hydro notes that this estimate may differ from actual GHG emission reductions as determined by the customer specific to their unique electrification project(s). Where an actual value has been provided to BC Hydro by the customer, or reported by the customer to the government through an Industrial Emissions Report, BC Hydro will show the customer-reported value in Column H (i) of [Table 5](#). BC Hydro may also conduct a technical review of baselines, calculations, and assumptions used to determine the GHG reductions in the Industrial Emissions Report. Any changes to the value reported in a previous reporting period will be reflected in the cumulative values in Column H (ii) of [Table 5](#). The methodology used for typical electrical energy impact calculations for LCE projects is as follows:

- total annual energy consumption = facility baseline electricity consumption + incremental LCE electricity consumption +/- baseline energy adjustments; and

- total average monthly electrical demand = baseline average monthly electrical demand + incremental LCE average monthly electrical demand +/- baseline demand adjustments.

Baseline adjustments are determined based on any net baseline energy consumption impacts that may be a result of the LCE project.

The two LCE projects (Project 3 and Project 4) completed in Fiscal 2020 have gone through a technical review and had a site specific measurement and verification plan for the estimated additional electricity consumption and demand. The plan was developed and included as part of the funding agreement between BC Hydro and the recipient. The respective methodology used for these two projects generally follow 'Option B, Retrofit Isolation: All Parameter Measurement', as set out in the International Performance Measurement & Verification Protocol (IPMVP) – Core Concepts October 2016 EVO 10000 – 1:2016.

4.4 Performance Metrics

BC Hydro outlines separately the different performance metrics used for the projects, studies, public awareness campaigns, and standards enablers described in section [4.2](#) above.

4.4.1 LCE Projects

For the two projects (Project 3 and Project 4) completed in Fiscal 2020, using above mentioned methodologies for electricity consumption, demand and GHG emission reductions, BC Hydro will consider the following to verify project performance:

1. Project completion – has the project progressed as described in the application?;
2. Electrical energy consumption – did the project consume the amount of electrical energy as described in the LCE Agreement?; and

3. GHG emission reduction – was fossil fuel consumption replaced with BC Hydro electricity? Was an associated GHG emission reduction realized?

Measurement and verification activities for the projects are underway.

4.4.2 LCE Studies, Research and Pilots

As discussed in section [4.2](#) above, BC Hydro provided funding to support six studies and seven research/pilot projects. Those studies are critical in enabling customers to build the business case for project implementation as well as providing key inputs on barriers, costs, and benefits into BC Hydro program development and design.

Performance metrics for LCE studies consider whether the study/project may yield the following information, such as

1. information which could inform and improve accuracy of the project modeling assumptions;
2. information which could inform and improve understanding of market barriers and customer drivers;
3. site specific investigation and engineering analysis at a level sufficient to determine if advancing the project would provide tangible benefits that would make business sense for the customer and BC Hydro to continue supporting the project; and
4. learnings that may inform future BC Hydro programs and customer opportunities.

The six studies and seven research/pilot projects completed in Fiscal 2020 performed well against the above performance metrics.

4.4.3 Public Awareness Campaign

For public awareness campaigns, BC Hydro may track the performance of awareness activities through measures such as:

- Reach measures that are volume-based and support building awareness through impressions (TV, out of home advertising, online), video views, and media pickups;
- Traction measures that are sentiment-based and support receptiveness such as favourability, likability, changes pre to post; and
- Action measures that drive participation through clicks, sessions, contest entries, social engagement, and customer intercepts at events or program participation.

The public awareness campaign completed in Fiscal 2020 performed well against the above performance metrics.

4.4.4 Standards Enabler Undertakings

BC Hydro works with standards making bodies such as various levels of government that are responsible for land use, building codes, product and equipment standards, land use policies, bylaws, and community plans, to advance standards for technologies that use electricity instead of other sources of energy that produce more GHG emissions, or technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more GHG emissions. Performance metrics for standards enabler undertakings consider whether the project/activity may yield information to or enable advancement of the government efforts in standards, policies, bylaws, and community plans, which enable electrification of new construction and retrofits within the built environment and transportation sector.

The standards enabler undertakings completed in Fiscal 2020 performed well against the above performance metrics.

4.5 Cost-Effectiveness

As required under section 4(4) of the GGRR, undertakings are in the class of undertakings prescribed by sections 4(3)(a) or 4(3)(b) of the GGRR only if they satisfy a cost-effectiveness test. That cost-effectiveness test is defined in section 4(1) of the GGRR and requires that each undertaking that is an undertaking within the class of undertakings prescribed by subsections 4(3)(a) or 4(3)(b) of the GGRR have a positive net present value (NPV), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) and 4(3)(b) of the GGRR. The GGRR cost-effectiveness test is measured only at the time BC Hydro decides to carry out the program.

[Table 5](#) shows the GGRR net present value (**NPV**) of the various LCE projects or programs prescribed under section 4(3)(a) and 4(3)(b) of the GGRR. The total GGRR NPV of these undertakings is \$118.6 million which includes actual and committed expenditures and benefits from past, current, and future reporting periods. The GGRR NPV indicates that these undertakings are cost-effective.

4.6 Summary of Results

4.6.1 Explanation of Terms

[Table 4](#) includes a description of the information provided in [Table 5](#) below with regard to the LCE Programs.

**Table 4 LCE Programs Results Table:
Explanation of Terms**

Column	Heading	Descriptions
A	GGRR	Applicable section of the GGRR.
B	Project / Program/Contract / Expenditure	Low-carbon electrification activities to encourage or enable the use of electricity in place of other sources of energy that produce more greenhouse gas emissions.
C ⁽ⁱ⁾	Actual Expenditure (\$ million)	Costs incurred at the end of the current reporting fiscal year.
C ⁽ⁱⁱ⁾	Cumulative: Actual Expenditures (\$ million)	The sum of successive costs incurred as at the end of the reporting fiscal year.
D	Cost Effectiveness (\$ million): NPV to 2030 (Fiscal 2031)	The present value of the costs and benefits are determined using a discount rate equal to BC Hydro's weighted average cost of capital. The present value of the costs are subtracted from the present value of the benefits from the project start year to last year in the calculation period (Fiscal 2031) to determine the net present value for the project.
E	Cost Effectiveness (\$ million): GGRR NPV to 2030 (Fiscal 2031)	The calculation of the GGRR NPV is based on costs and benefits as defined in the GGRR as of Fiscal 2018. Per that definition, benefits mean all revenues BC Hydro expects to earn as a result of implementing LCE programs falling under subsections 4(3)(a) or 4(3)(b), less revenues that would have been earned from the sale of that electricity to export markets. Costs mean all the costs BC Hydro expects to incur to implement LCE programs falling under subsections 4(3)(a) or 4(3)(b), including development and administration costs. For clarity, costs includes historic and future cost, committed expenditures and benefits from past, current and future reporting periods.
F ⁽ⁱ⁾	Actual: Additional Energy Consumption (MWh/year)	The average annual additional energy consumption estimated to be delivered from the project in the current reporting fiscal period.
F ⁽ⁱⁱ⁾	Cumulative: Additional Energy Consumption (MWh/year)	The sum of the successive average annual additional energy consumption estimated to be delivered from the project as at the end of the reporting fiscal period.
G ⁽ⁱ⁾	Actual: Additional Capacity Demand (MW)	The total energy demand added.

Column	Heading	Descriptions
G(ii)	Cumulative: Additional Capacity Demand (MW)	The sum of the successive energy demand addition.
H(i)	Actual: Estimated GHG Emission Reductions (tonnes CO ₂ e/year)	The average annual tonnes per year of carbon dioxide equivalent reductions from the project in the current reporting fiscal period.
H(ii)	Cumulative: Estimated GHG Emission Reductions (tonnes CO ₂ e/year)	The sum of the successive additional average annual tonnes per year of carbon dioxide equivalent reductions from the project as at the end of the reporting fiscal period.

4.6.2 Results Table

[Table 5](#) summarizes information regarding the LCE Programs that are undertakings prescribed by sections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR. The indications of "n/a" in [Table 5](#) are due to: (1) the nature of the project, study or program, such that requested information cannot be obtained; or (2) the project, study, or program are prescribed by sections 4(3)(c) and 4(3)(d) of the GGRR and thus the cost-effectiveness test does not apply. BC Hydro provides as Attachment 3 an excel spreadsheet with annual expenditures, in total and by project, study, or program, as outlined in the GGRR Reporting Requirements.

1 **Table 5 LCE Programs¹ Results for Year Ending March 31, 2020**

	A GGRR	B Project/Program/Contract/Expenditure	C Expenditure (\$ million)		D Cost Effectiveness (\$ million)		E Additional Energy Consumption ³ (MWh/year)		F Additional Demand (MW)		G GHG Emission Reductions (tonnes CO ₂ e/year)	
			Actual (i)	Cumulative (ii)	NPV to 2030 (Fiscal 2031)	GGRR NPV to 2030 (Fiscal 2031) ²	Actual (i)	Cuml (ii)	Actual (i)	Cumulative (ii)	Actual (i)	Cumulative (ii)
1	4(3)(c)	Vancouver Fraser Port Authority	0.00	0.07	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	4(3)(c)	██████████ (Project 1) ⁵	0.00	0.01	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3	4(3)(c)	██████████ (Project 2) ⁵	0.00	0.01	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4	4(3)(c)	BC Hydro Program Staff Labour	0.00	0.12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	4(3)(a)	██████████ (Project 3)	1.42	7.77	64.3	64.3	26,061	130,305	3.5	17.5	15,582 ⁴	77,911
6	4(3)(a)	██████████ (Project 4)	11.25	11.25	45.9	110.2	186,150	186,150	25.0	25.0	111,302 ⁴	111,302
7	4(3)(a)	Thompson Rivers University	0.00	0.28	0.3	110.5	0	2,737	0.0	0.0	0	562
8	4(3)(c)	Copper Mountain Mine	0.00	0.07	n/a	110.5	n/a	n/a	n/a	n/a	n/a	n/a
9	4(3)(c)	Translink	0.50	0.50	n/a	110.5	1,254	1,254	0.8	0.8	215	215
10	4(3)(a)(b)	BC Hydro LCE Program	3.17	3.57	8.2	118.6	0	0	0.0	0.0	0	0
11	4(3)(c)	BC Hydro LCE Program	0.36	0.37	n/a	118.6	0	0	0.0	0.0	0	0
12	4(3)(d)	BC Hydro LCE Program	0.23	0.26	n/a	118.6	0	0	0.0	0.0	0	0
		Total	16.93	24.27	118.6	118.6	213,465	320,446	29.3	43.3	127,099	189,989

2 ¹ LCE Programs shown in the table include both LCE Initial Projects (rows 1 to 9) and associated expenditure and the BC Hydro LCE Program (rows 10 to 12). LCE Initial Projects are reported individually, with the introduction of the BC Hydro LCE Program
3 individual project expenditure has been aggregated.

4 ² Where a project/program has no actual or cumulative expenditures, but has an NPV, this means that the decision to go ahead with that project/program was made in this (or previous) reporting periods, but that the project/program is not expected to be
5 implemented until a future year.

6 ³ Values reported in column F represent the 'run rate' or annualized rate of additional energy consumption.

7 ⁴ The GHG emission reductions shown are associated with the electrification of Project 3 and 4 and they represent estimates based on engineering calculations at the time BC Hydro made the decision to carry out offering incentive funding to the project. The GHG
8 emission reductions associated with these projects are also referenced in section 5 of this report.

9 ⁵ Project 1 and 2 were described in the Fiscal 2018 Annual Report filed in July 2018.

4.7 LCE Programs by Region and Sector

The GGRR Reporting Requirements also request graphical depictions of the distribution by region in the Province and the distribution by customer sector where possible. The sectors (built environment, industrial process, and transportation) shown in the chart below align with those reflected in the CleanBC plan and in the description in section [4.2](#) of this report. The requested graphical depictions are provided below. For the purpose of showing activities distributed by region and by sector we have used the term ‘Project’ to represent individual studies, research or pilot activities, or implementation projects where customers have acquired and installed equipment that uses electricity instead of other sources of energy that produce more GHG emissions as described in section [4.2](#). We did not include Public Awareness Campaigns in [Figure 1](#) or [Figure 2](#) as those activities were carried out Province-wide and targeted a single sector (transportation) and as such would not be meaningful in a graphical depiction.

[Figure 1](#) highlights that the highest number of projects are in the Lower Mainland, while [Figure 2](#) highlights that projects are equally distributed across sectors.

Figure 1 Projects by Geographic Region

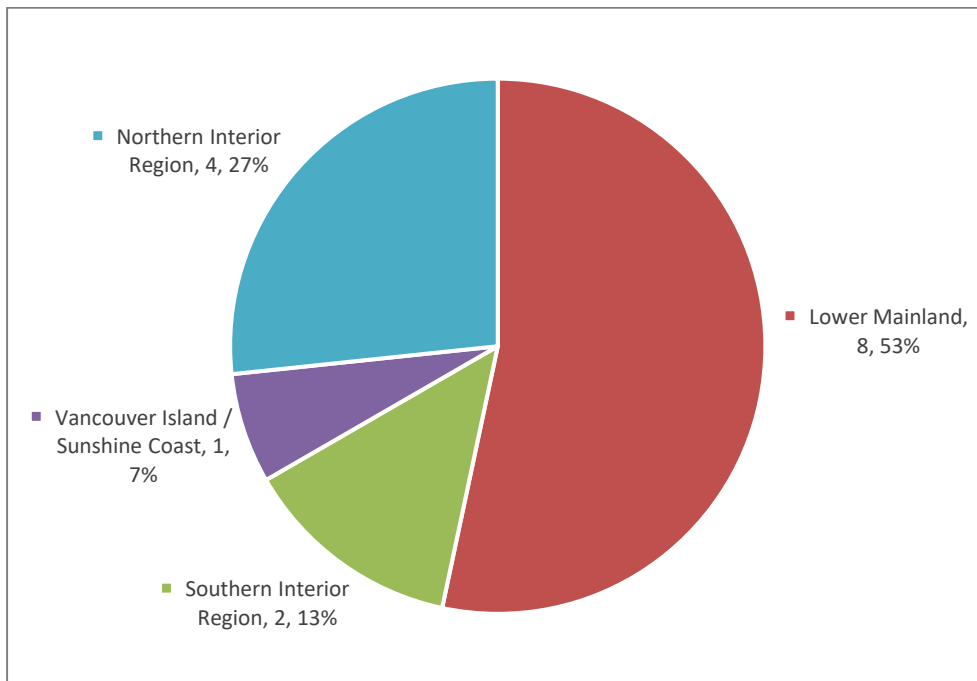
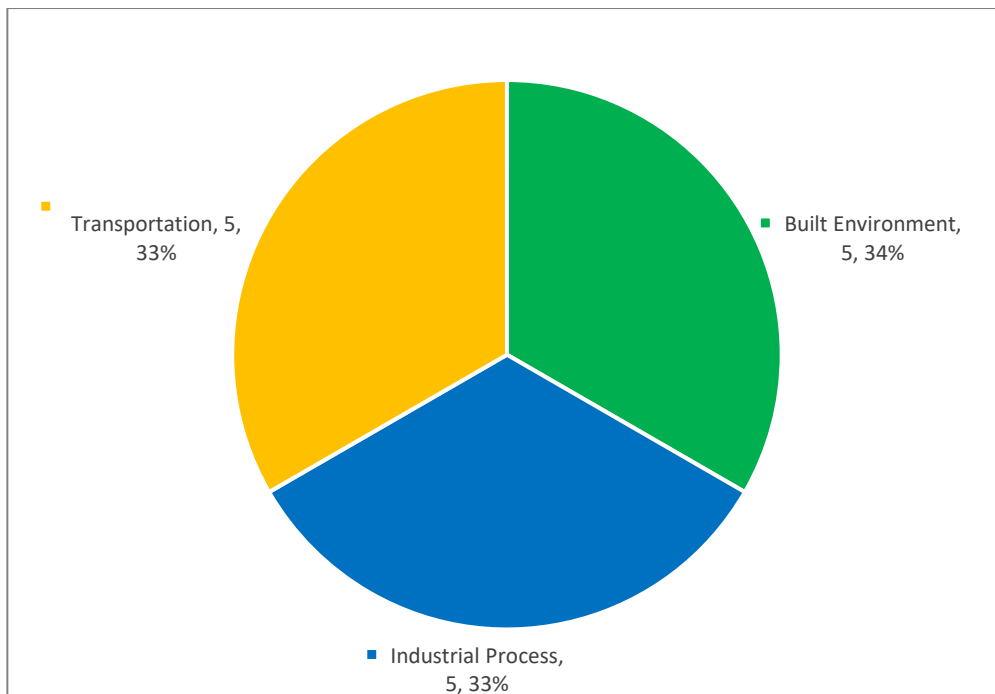


Figure 2 Projects by Sector



5 LCE Infrastructure Projects

5.1 Overview

In this section, we describe the LCE Infrastructure Projects (i.e., being projects within the classes of undertaking prescribed by subsections 4(2) or 4(3)(e) of the GGRR) and available evaluation results.

Northeast British Columbia is forecasted to experience a significant increase in natural gas production and processing capacity, primarily in the Montney region. In the absence of adequate electricity supply, much of this development will be powered by natural-gas fired production processes. Meanwhile, BC Hydro's transmission system in this region is constrained. Further, the transmission system's ability to supply new loads in the South Peace region at all, even with a reduced level of reliability, is expected to be exceeded in summer 2021. Accordingly, BC Hydro will construct and operate new transmission and distribution facilities, and/or provide for [REDACTED] generation until such system upgrades are completed. These LCE Infrastructure Projects will enable the provision of reliable electricity service as a power supply alternative to carbon-based fuels, which will enable the reduction of existing GHG emissions or avoidance of future incremental GHG emissions.

5.2 Fiscal 2020 LCE Infrastructure Projects

In Fiscal 2020, BC Hydro incurred expenditures of \$84.7 million in regard to two LCE Infrastructure Projects. Expenditures incurred and recorded in future fiscal years will be included in the applicable future GGRR annual report.

5.2.1 Peace Region Electricity Supply (PRES) Project

The PRES Project was introduced in the Fiscal 2018 GGRR Annual Report. As explained in the Fiscal 2018 report, the PRES Project will enable natural gas producers and processors to electrify their existing and new operations, rather than self-supplying with natural gas. This includes natural gas producers and processors

as defined in GRRR sections 4(2)(a)(i) and (ii). The PRES Project is expected to reduce GHG emissions in B.C. from any existing plant or from any prospective new plant that elects to take supply from BC Hydro rather than self-supply using natural gas.

The PRES Project was approved by BC Hydro's Board of Directors for implementation in June 2018. When BC Hydro's Board of Directors approved the PRES project, BC Hydro reasonably expected that the PRES project would have an in-service date no later than December 31, 2022. Therefore, the PRES Project is a prescribed undertaking pursuant to GRRR section 4(2). As of this report, the PRES Project has an expected in-service date of October 2021.

The PRES Project is currently in the Implementation Phase and has an estimated total capital cost of \$285 million. As of the end of Fiscal 2020, BC Hydro has incurred \$152.9 million in total capital expenditures on developing the PRES Project, of which \$83.0 million was incurred in Fiscal 2020.

During Fiscal 2020, BC Hydro completed the detailed design work for the PRES Project, and completed clearing and access road construction for the new transmission line right-of-way. BC Hydro also started construction work on the transmission line, continued work at South Bank Substation and completed construction work at Shell Groundbirch Substation.

BC Hydro will report on performance metrics and environmental benefits of undertaking the PRES Project when it is in-service, and existing and new natural gas producing or processing plant operations are connected to the BC Hydro's system.

5.2.2 [REDACTED] Generation Agreement

As reported in the Fiscal 2018 GRRR Annual Report, BC Hydro entered into a Generation Agreement with Company X to provide [REDACTED] generation as a [REDACTED]

During periods of actual or anticipated system constraint, under the Generation Agreement, BC Hydro has the right to direct Company X to [REDACTED] island its facilities in Northeast B.C. [REDACTED] from the grid and self-supply with electricity produced by Company X's on-site generating units. BC Hydro treats Company X's generation as a system resource, such that any self-generated electricity [REDACTED] replaces electricity that would otherwise be provided from the BC Hydro transmission system. The Generation Agreement achieves the purpose of providing reliable electricity supply to electrified Company X's facilities during events of system constraint [REDACTED].

The total forecast nominal value of the Generation Agreement is \$12.0 million. Total expenditures incurred in Fiscal 2020 with respect to this [REDACTED] agreement are \$1.7 million.

5.3 Quantitative Data – Methodology & Assumptions

BC Hydro has developed criteria to qualify customer loads for inclusion in its estimates for GHG emissions reduced or avoided due to the PRES Project.

The customer load to be included:

- Must be a new natural gas processing plant (including associated gas gathering and wellpad facilities) or existing plant converting to take grid service which takes, or commits to take, electricity service from BC Hydro in Fiscal 2018 or later;
- Would have used natural gas for power supply in the absence of BC Hydro's commitment to construct and operate new facilities; and
- Will be served by the PRES Project once it is placed in service.

These criteria thus include: (i) existing "brownfield" loads which fuel-switch from carbon-based fuel to grid electricity; and (ii) new "greenfield" loads that make

the investment decision to take grid electricity as an alternative to carbon-based fuels for power supply.

BC Hydro notes that these criteria differ from the current British Columbia Greenhouse Gas Offset Protocol (*Fuel Switch Version 1.0, dated August 16, 2018*) which is specific to the replacement of existing gas-powered turbines with electrical grid power. Under the current protocol, GHG emission reductions would only arise where an existing customer facility fuel switches from a carbon-based fuel (such as natural gas) to low-carbon grid electricity and would not apply to any new plant that elects to be served with grid electricity in the first instance.

5.4 Performance Metrics

The GGRR performance metrics for the PRES Project are listed in [Table 6](#) below.

Table 6 PRES Project: GGRR Performance Metrics

Type of Facility	Project(s)	Performance Metrics
Transmission & Distribution	PRES Project	New load served GHG emissions reduction
Generation	Generation Agreement	New load served Mitigation of system constraints GHG emissions reduction

A key purpose of the PRES Project is to enable a clean, reliable source of electrical power supply to existing and new natural gas processing operations. In the absence of the PRES Project, there would be no grid service alternative. These plant operations would otherwise need to use natural gas (or other fossil fuels) for power supply. Since greenhouse gases are emitted when fossil fuels are burned to create power, the PRES Project will reduce GHG emissions in British Columbia for any existing plant that elects to take grid service rather than self-supply using natural gas.

GHG Emission Reduction Methodology

BC Hydro will estimate the impact the PRES Project will have on GHG emission reductions in British Columbia based on the assumptions and methodology set out in section [4.3](#) of this report. BC Hydro will apply these same assumptions and methodology to estimate the impact that [REDACTED] generation will have on GHG emission reductions in British Columbia until the PRES Project is in-service. For Fiscal 2020, the GHG emissions intensity factors determined in accordance with this methodology are listed below for convenience:

- Average emissions intensity factor for natural gas turbine [REDACTED].¹¹
- Less emissions intensity factor for BC Hydro grid electricity:
[REDACTED].¹²
- Net emissions intensity factor for electrified loads: [REDACTED].

Determination of Eligible Loads for GHG Emission Reduction

In Fiscal 2020, certain Company X facilities were electrified with the support provided through the Generation Agreement (to ensure reliable electricity supply) and the Incentive Agreement (to provide supporting funds for investment in electrical infrastructure) described in the previous sections. Absent these agreements, BC Hydro considers that the Company X loads would not have connected to the BC Hydro transmission system and taken grid service.

As discussed in section [4.2](#) above, Company X has two sites which are relevant to the prescribed undertakings, the [REDACTED] (Project 3) and the [REDACTED] (Project 4) sites.

¹¹ The efficiency assumption of 29.5 per cent for gas turbines was developed by calculating the weighted average efficiency from metered data of two customer operated gas turbine electrical generation units.

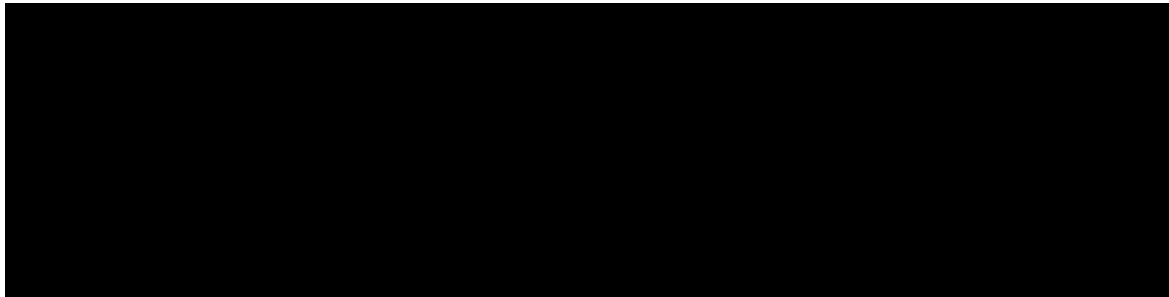
¹² Source: British Columbia Government: 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, page 17.

The Project 3 site was energized from the BC Hydro transmission system in Fiscal 2019. This site comprises three discrete load centres: three gas processing plants and one field/gathering system.

Of the three gas processing plants: one gas processing plant's (Gas Plant 1) load is not eligible for GHG emission calculation because it was previously served from the BC Hydro distribution system; one gas processing plant's (Gas Plant 2) load was new to the BC Hydro system in Fiscal 2019; and the final gas processing plant has not yet been constructed.

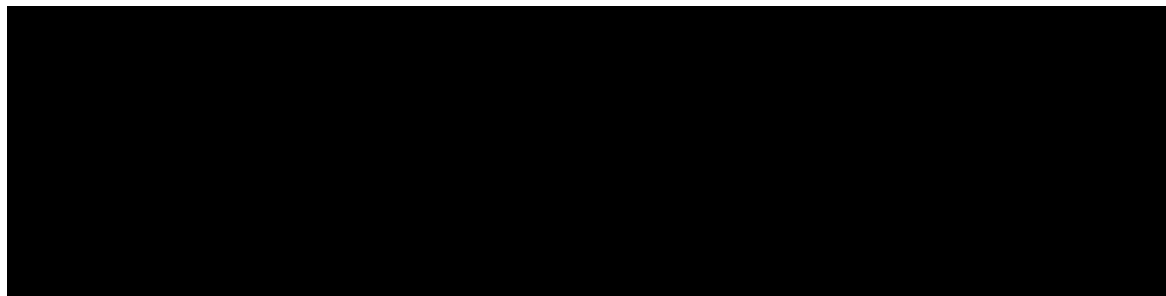
The load associated with the field/gathering system is being phased into the BC Hydro system. One phase of the field/gathering system load was introduced to the BC Hydro system in Fiscal 2019. Another phase of the field/gathering system load is new to the BC Hydro system in Fiscal 2020. Further phases of the field/gathering system are expected to join the system in future fiscal years.

For Fiscal 2020, total new load served by BC Hydro was 120,156 MWh, with an estimated GHG emission reduction of 71,853 tonnes CO₂e.



The Project 4 site was energized from the BC Hydro transmission system in Fiscal 2019. This site comprises two gas processing plants, one of which was operational in Fiscal 2019 (Gas Plant 1), while the other was under construction (Gas Plant 2). Project 4's Gas Plant 2 is joining the BC Hydro system in phases. The first phase connected to the grid in Fiscal 2020. For Fiscal 2020, total new load

served by BC Hydro was 148,668 MWh, with an estimated GHG emission reduction of 88,903 tonnes CO₂e.



BC Hydro notes that for each site, electrical energy consumption arising from the electrification of new loads is used to determine associated GHG emission reductions pursuant to the methodology described in section [4.3](#). These values have been incorporated into Summary of Results

5.4.1 Explanation of Terms

[Table 7](#) includes a description of the information provided in the results table for LCE Infrastructure Projects. The reason for the indications of "n/a's" is due to the nature of the PRES Project as of March 31, 2020, as described above.

Table 7 LCE Infrastructure Projects Results
Table: Explanation of Terms

Column	Heading	Descriptions
A	Prescribed Undertaking	Type of prescribed undertaking.
B	Name	Project, program, or customer name.
C (i)	Actual (\$ million)	Actual costs in millions incurred at the end of the current reporting fiscal.
C (ii)	Cumulative Costs (\$ million)	Cumulative actual costs in millions incurred from first year of expenditure to the end of the current reporting fiscal.
C (iii)	Forecast Total (\$ million)	Approved Anticipated Total Capital Cost of Project.
D	Capacity of Facility (MW)	Planned facility capacity in megawatts at N-1 and N-0.
E	Total Capacity Committed/Secured (MW)	Cumulative total capacity committed and secured until the end of the current fiscal year in megawatts.
F	Total Customer Load(s) Served (MW)	Cumulative total customer loads served as at the end of the current fiscal year in megawatts.

Column	Heading	Descriptions
G	Total Energy Provided to Customers (MW/h)	Cumulative total energy provided to customers as at the end of the current fiscal year in megawatts per hour.
H (i)	Actual: GHG Emissions Reduction Estimates (tonnes CO ₂ e/year)	Actual GHG Emissions Reduction at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
H (ii)	Cumulative: GHG Emissions Reduction Estimates (tonnes CO ₂ e/year)	Cumulative GHG Emissions Reduction as at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
I (i)	Type: Fossil Fuel(s) Avoided Or Displaced	Type of fossil fuels avoided or displaced or likely to be avoided or displaced.
I (ii)	Amount: Fossil Fuel(s) Avoided Or Displaced	Amount of fossil fuels avoided or displaced or likely to be avoided or displaced.

5.4.2 Results Table

[Table 8](#) provides the results for LCE Infrastructure Projects with expenditures in Fiscal 2020.

1 **Table 8 LCE Infrastructure Projects Results for Year Ending March 31, 2020**

	A	B	C			D	E	F	G	H		I	
	Prescribed Undertaking	Name	Cost			Capacity of Facility (MW)	Total Capacity Committed/ Secured (MW)	Total Customer Load(s) Served (MW)	Total Energy ¹ Provided to Customers (MW/h)	GHG Emissions Reduction Estimates ² (tonnes CO ₂ e/ year)		Fossil Fuel(s) Avoided or Displaced	
			Actual (\$ million) (i)	Cumulative (\$ million) (ii) ³	Forecast Total (\$ million) (iii)					Actual (i)	Cumulative (ii)	Type (i)	Amount (ii)
1	T&D	PRES Project	83.0	152.9	285	800 - 950	24	n/a	n/a	n/a	n/a	n/a	n/a
2	Generation	(Company X)	1.7	3.3	12	24	24	38	268,824	160,756	238,568	n/a	n/a

2 ¹ Reflects total new facility load served from the BC Hydro transmission system in F2020. 169,636 MWh of load is from existing brownfield facilities that fuel-switched to grid power. 99,188 MWh of load is from new greenfield facilities that electrified.

3 ² The GHG Emissions Reduction Estimates are specific to eligible Project 3 and Project 4 plant loads that were served by BC Hydro in Fiscal 2020 in place of natural gas-fired supply.

4 ³ An additional expenditure of \$0.3 million was incurred for generation dispatched as an energy resource over 11 days in March 2019. BC Hydro does not consider the associated dispatch costs to be reportable GGRR costs because they were

5 incurred for a purpose ancillary to proving reliable network service.

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

BC Hydro Fiscal 2022 Revenue Requirements Application

Appendix Y

Proposed Fiscal 2022 Rates

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1 Introduction

Section [2](#) of this appendix describes how the requested rate increase will be applied to the default, tiered rates for BC Hydro's residential and transmission service rate classes using BCUC-approved pricing principles. The default rates for the other rate classes do not require the use of the BCUC-approved pricing principles and have been determined by increasing each component of the rate by the requested rate increase.

Section [3](#) contains the fiscal 2022 rates which are requested to be effective April 1, 2021 on an interim and refundable basis.

[Table Y-1](#) of this appendix sets out the rates that will be applicable to each of the Rate Schedules in each rate class for fiscal 2022 and compares them to the fiscal 2021 rates, which were approved on a final basis by BCUC Order No. G-246-20.

BC Hydro's Open Access Transmission Tariff (**OATT**) rates are explained in Chapter 9 of the Application. [Table Y-2](#) of this appendix sets out the applicable OATT rates for fiscal 2022 and compares them to the fiscal 2021 rates, which were approved on a final basis by BCUC Order No. G-246-20.

2 Application of Rate Increases

2.1 Residential Rates

2.1.1 Rate Schedules (RS) 1101, 1121 – Residential Service

Rate Schedule 1101 is the Residential Inclining Block (**RIB**) rate, which is the default Residential rate, while Rate Schedule 1121 is the RIB rate for Multiple Residential Service. The RIB rate structure for Rate Schedules 1101 and 1121 is a Basic Charge and a two-step inclining block rate, with the first step called the Step-1

energy rate and the second step called the Step-2 energy rate. The RIB rate was implemented on October 1, 2008.

The term “pricing principles” refers to how revenue requirements rate increases are applied to each of the RIB rate’s pricing elements (Step-1 energy rate, Step-2 energy rate and Basic Charge). The approved RIB pricing principles for fiscal 2022 for Rate Schedules 1101 and 1121 are to uniformly increase the three pricing elements of the RIB rate by the amount of the approved rate increases. These pricing principles have been in place for a number of years and were most recently approved for fiscal 2021 and fiscal 2022 by BCUC Order No. G-62-20.

BC Hydro uses the approved pricing principles to derive the RIB rates shown in [Table Y-1](#) below. To derive fiscal 2022 RIB rates, each of the three components of the RIB rate are increased by the proposed rate increase of 1.16 per cent.

2.2 Transmission Service Rates

2.2.1 Rate Schedule (RS) 1823 – Transmission Service – Stepped Rate

The pricing principles for the Rate Schedule 1823 Stepped Rate were first approved for fiscal 2017 to fiscal 2019 by Directive 9 of BCUC Order No. G-5-17. The pricing principles were extended to fiscal 2020 and fiscal 2021 by BCUC Order No. G-93-19.

Under the pricing principles:

- For fiscal 2017, the Tier 2 rate was set to the lower end of BC Hydro’s energy long run marginal cost and the Tier 1 rate was set to reflect the 4.0 per cent revenue requirements rate increase according to the bill neutrality approach i.e., 90 per cent of the Tier 1 rate plus 10 per cent of the Tier 2 rate is equal to the flat rate (Rate Schedule 1827 energy rate or the Rate Schedule 1823 Energy Charge A); and

-
- For fiscal 2018 to fiscal 2021, the applicable revenue requirements rate increases were applied equally to both Tier 1 and Tier 2 energy rates.
- BC Hydro intends to file a RS 1823 Stepped Rate pricing principles application to extend the current fiscal 2021 approved pricing principles for fiscal 2022 in February 2021.
- The fiscal 2022 Transmission Service stepped rates in [Table Y-1](#) are based on the assumption that the BCUC approves BC Hydro's application to extend the pricing principles to the end of fiscal 2022. Therefore, the proposed fiscal 2022 rate increase of 1.16 per cent is applied equally to the RS 1823 Tier 1 energy rate and the Tier 2 energy rate.

3 Summary of Fiscal 2022 Rates

[Table Y-1](#) below provides the rates in each BC Hydro rate schedule for fiscal 2022 and a comparison to the fiscal 2021 rates which were approved on a final basis by BCUC Order No. G-246-20.

Table Y-1 Fiscal 2021 and Fiscal 2022 Rates

Rate Class	Rate Schedule	Rate	Fiscal 2021 Approved -1.62%	Fiscal 2022 Rate Increase 1.16%
Residential	1101/1121	Basic Charge (\$/day)	0.2056	0.2080
		Step-1 energy rate (\$/kWh)	0.0930	0.0941
		Step-2 energy rate (\$/kWh)	0.1394	0.1410
Residential	1105 (closed)	Energy rate (\$/kWh)	0.0787	0.0858

Rate Class	Rate Schedule	Rate	Fiscal 2021	Fiscal 2022
			Approved -1.62%	Rate Increase 1.16%
Residential Zone II	1107/1127	Basic Charge (\$/day)	0.2193	0.2218
		Step-1 energy rate (\$/kWh)	0.1114	0.1127
		Step-2 energy rate (\$/kWh)	0.1913	0.1935
Residential	1148 (closed)	Basic Charge (\$/day)	0.2193	0.2218
		Energy rate \$/kWh	0.1114	0.1127
Residential	1151/1161	Basic Charge (\$/day)	0.2193	0.2218
		Energy rate \$/kWh	0.1114	0.1127
Exempt General Service	1200/1201/1210/ 1211	Basic Charge (\$/day)	0.2630	0.2661
		Demand rate - Step-1 (\$/kW)	0	0
		Demand rate - Step-2 (\$/kW)	6.41	6.48
		Demand rate - Step-3 (\$/kW)	12.29	12.43
		Energy Rate - Tier 1 (\$/kWh)	0.1251	0.1266
		Energy Rate - Tier 2 (\$/kWh)	0.0601	0.0608
General Service	1205/1206/1207	Energy Rate - Tier 1 (\$/kWh)	0.0609	0.0616
		Energy Rate - Tier 2 (\$/kWh)	0.0398	0.0403
Small General Service Zone II	1234	Basic Charge (\$/day)	0.263	0.2661
		Energy Rate - Tier 1 (\$/kWh)	0.1251	0.1266
		Energy Rate - Tier 2 (\$/kWh)	0.2083	0.2107

Rate Class	Rate Schedule	Rate	Fiscal 2021	Fiscal 2022
			Approved -1.62%	Rate Increase 1.16%
Distribution Service	1253	Monthly Minimum energy charge(\$/month)	48.22	48.78
Large General Service Zone II	1255/1256/1265/1266	Basic Charge (\$/day)	0.263	0.2661
		Energy Rate - Tier 1 (\$/kWh)	0.1251	0.1266
		Energy Rate - Tier 2 (\$/kWh)	0.2083	0.2107
Distribution Service	1268	Energy charge (\$/kWh)	0.00194	0.00196
Shore Power Service (Distribution)	1280	Monthly Charge (\$/month)	150	150
		Energy Rate (\$/kWh)	0.10339	0.10459
Small General Service	1300/1301/1310/1311	Basic Charge (\$/day)	0.3586	0.3628
		Energy Rate (\$/kWh)	0.1233	0.1247
Irrigation	1401	Irrigation season energy rate (\$/kWh)	0.0602	0.0609
		Non-irrigation season energy rate - Tier 1 (\$/kWh)	0.0602	0.0609
		Non-irrigation season energy rate - Tier 2 (\$/kWh)	0.4773	0.4828
		Minimum charge irrigation season \$/kW	6.02	6.09
		Minimum charge non-irrigation season if consumption >500 kWh (\$ per kW)	48.15	48.71

Rate Class	Rate Schedule	Rate	Fiscal 2021	Fiscal 2022
			Approved -1.62%	Rate Increase 1.16%
Medium General Service	1500/1501/1510/ 1511	Basic Charge (\$/day)	0.263	0.2661
		Demand rate - all kW (\$/kW)	5.33	5.39
		Energy rate - all kWh (\$/kWh)	0.0952	0.0963
Large General Service	1600/1601/1610/ 1611	Basic Charge (\$/day)	0.263	0.2661
		Demand rate – all kW (\$/kW)	12.14	12.28
		Energy rate - all kWh (\$/kWh)	0.0596	0.0603
Large General Service	1640 / 1641 / 1642 / 1643	Basic Charge (\$/day)		0.2661
		Demand rate - all kW		12.28
		Energy rate - all kWh		0.0741
Large General Service	1650 / 1651 / 1652 / 1653	Basic Charge (\$/day)	0.2630	0.2661
		Demand rate - all kW	0.00	0.00
		Energy rate - all kWh	0.0903	0.0913
Street Lighting	1701	50 W or less LED (\$/month)	15.08	15.25
		51-80 W LED (\$/month)	18.77	18.99
		81-120 W LED (\$/month)	23.50	23.77
		>120 W LED (\$/month)	27.57	27.89
		100 SV fixture rate (\$/month)	19.28	19.50
		150 SV fixture (\$/month)	23.00	23.27
		200 SV fixture (\$/month)	26.55	26.86

Rate Class	Rate Schedule	Rate	Fiscal 2021	Fiscal 2022
			Approved -1.62%	Rate Increase 1.16%
		175 MV fixture (\$/month)	21.19	21.44
		250 MV fixture (\$/month)	24.42	24.70
		400 MV fixture (\$/month)	31.47	31.84
Street Lighting	1702	Each Unmetered fixture (\$/watt per month)	0.0371	0.0375
		Each Metered fixture (\$/kWh)	0.1114	0.1127
Street Lighting	1703	Energy rate (\$/watt per month)	0.0371	0.0375
		Contact rate (\$/contact per month)	1.11	1.12
Street Lighting	1704	Energy rate \$/kWh	0.1114	0.1127
Street Lighting	1755 (closed)	1. Pole owned by Customer		
		175 MV or 100 SV fixture charge (\$ per month)	18.07	18.28
		400 MV or 150 SV fixture charge (\$ per month)	31.15	31.51
		2. Pole on public property		
		175 MV or 100 SV fixture charge (\$ per month)	19.19	19.41
		400 MV or 150 SV fixture charge (\$ per month)	32.28	32.65

Rate Class	Rate Schedule	Rate	Fiscal 2021 Approved -1.62%	Fiscal 2022 Rate Increase 1.16%
		3. Pole paid by BC Hydro		
		175 MV or 100 SV fixture charge (\$ per month)	23.63	23.90
		400 MV or 150 SV fixture charge (\$ per month)	37.20	37.63
Transmission Service	1823	Demand rate (\$/kVA)	8.556	8.655
		Energy rate A (\$/kWh)	0.05015	0.05073
		Energy rate B - Tier 1 (\$/kWh)	0.04462	0.04514
		Energy rate B - Tier 2 (\$/kWh)	0.09995	0.10111
		Minimum demand (\$/kVA)	8.556	8.655
Transmission Service	1825	Demand rate (\$/kVA)	8.556	8.655
		Winter HLH energy rate (below 90%) (\$/kWh)	0.04462	0.04514
		Winter HLH energy rate (above 90%) (\$/kWh)	0.11153	0.11282
		Winter LLH energy rate (below 90%) (\$/kWh)	0.04462	0.04514
		Winter LLH energy rate (above 90%) (\$/kWh)	0.10109	0.10226
		Spring energy rate (below 90%) (\$/kWh)	0.04462	0.04514
		Spring energy rate (above 90%) (\$/kWh)	0.09003	0.09107

Rate Class	Rate Schedule	Rate	Fiscal 2021	Fiscal 2022
			Approved -1.62%	Rate Increase 1.16%
		Remaining energy rate (below 90%) (\$/kWh)	0.04462	0.04514
		Remaining energy rate (above 90%) (\$/kWh)	0.09872	0.09987
Transmission Service	1827	Demand rate (\$/kVA)	8.556	8.655
		Energy rate (\$/kWh)	0.05015	0.05073
		Minimum demand (\$/kVA)	8.556	8.655
Transmission Service	1852	Excess Demand rate (\$/kVA)	8.556	8.655
Transmission Service	1853	Minimum Monthly Charge (\$/month)	48.22	48.78
Transmission Service	1880	Administrative Charge per Period of Use (\$)	150.00	150.00
		Energy Rate (\$/kWh)	0.09995	0.10111
Shore Power Service (Transmission)	1891	Monthly Charge (\$/month)	150	150
		Energy Rate (\$/kWh)	0.09995	0.10111
Transmission Service FortisBC	3808	Demand rate (\$/kW)	8.556	8.655
		Energy rate - tranche 1 (\$/kWh)	0.05015	0.05073
		Energy rate – tranche 2 (\$/kWh)	0.09509	0.09509
Deferral Account Rate Rider	1901	Per cent	0	0

- 1 [Table Y-2](#) below provides the OATT rates for fiscal 2022 and a comparison to the
- 2 fiscal 2021 OATT rates which were approved on a final basis by BCUC Order
- 3 No. G-246-20 in the Previous Application.

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Table Y-2 Fiscal 2021 and Fiscal 2022 Rates

Rate Schedule	Rate Class	Fiscal 2021 Approved	Fiscal 2022
Attachment H	NITS Revenue Requirement (\$)	964,849,000	985,900,800
00	NITS Monthly Rate (\$)	80,404,000	82,158,400
01	Long Term Firm Point-to-Point		
	Yearly - \$/MW of Reserved Capacity per year	81,531	78,862
	Short Term Firm and Non-Firm Maximum Price for Delivery		
	Monthly - \$/MW of Reserved Capacity per month	6,794.28	6,571.79
	Weekly - \$/MW of Reserved Capacity per week	1,567.91	1,516.57
	Daily - \$/MW of Reserved Capacity per day	223.37	216.06
	Hourly - \$/MW of Reserved Capacity per hour	9.31	9.00
03	Scheduling, System Control and Dispatch Service (\$)		
	per MW of Reserved Capacity per hour	0.139	0.155