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April 27, 2017

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck
Commission Secretary and Manager, Regulatory Support

Dear Sirs/Mesdames:

Re: FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan) - Project No. 3698896

We are counsel to the Commercial Energy Consumers Association of British Columbia (CEC). Attached please find the CEC's second set of Information Requests with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: FortisBC Inc.
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

INFORMATION REQUEST #2

FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan) - Project No. 3698896

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33. **Reference: Exhibit B-9 Shadrack IR 17.i – 17ii**

17. With reference to A3 BCUC IR #1.19 has FBC experienced any time, since 2010, an inability to purchase power on the spot market at any price?

Response:

Yes, on April 22, 2013 FBC attempted to secure market power for one hour in the morning, and could not at any cost.

i. On what dates and for what length of hours did this occur?

Response:

Please refer to the response to Shadrak IR1.17i.

ii. Did this situation result in power outages or forced shut down of certain customers' electricity supply? Please elaborate.

Response:

In this situation, FBC was attempting to purchase a relatively small volume of 10 MW in order to meet forecast demand plus a reasonable buffer, which is typically 15 to 30 MW, depending on the hour. Actual load for the hour was such that the 10 MW was not required to meet load, and therefore it did not cause an imbalance on the FBC system. Had it caused an imbalance, it would not have resulted in a forced shut down of any customer's electricity supply, as FBC has contractual methods of dealing with any imbalance transfer with BC Hydro.

33.1. There was only one hour in more than six years when FBC was unable to secure market power. That is a historical probability of less than 1/52560 or 0.000019. Does FBC expect that probability to increase or decrease over the next 10 years? Please explain why or why not and provide a discussion of the factors that are expected influence the availability of market power.

33.1.1. If FBC expects that probability to change in the next t ten years, please provide FBC's expected probability that it will be unable to access market power at any price.

33.2. In answer to Shadrack 17ii, FBC states it has contractual methods with BC Hydro to deal with any imbalance transfer problem. Please provide an overview of the contracts with BC Hydro that mitigate the risk of imbalance transfer to BC Hydro, and identify any limitations within these contracts.

33.3. Please provide FBC's views as to the reliability of these contractual methods for dealing with imbalance transfer, and provide the hourly probability that in the next ten years that BC Hydro will be unable to provide power in the event FBC is unable to access market power.

33.4. Please provide FBC's calculated joint probability that both of the following circumstances will occur in the same hour in the next ten years.

a) market power will be unavailable to FBC and

b) BC Hydro will be unable to provide power to deal with an imbalance transfer problem

33.5. Please provide a similar calculation for the next twenty years.

34. Reference: Exhibit B-9 Shadrack IR 9ii

Response:

As a result of the Canal Plant Agreement (CPA), the overall physical balancing of generation and load in BC is done by BC Hydro. Typically, BC Hydro does not use FBC's Kootenay River facilities as a balancing resource for the province. On an hourly basis, FBC must ensure it has resources in place to meet overall customer needs, which includes using the maximum amount of generating capability from the Kootenay River facilities derived from entitlement under the CPA, even though those units may not be generating at their maximum capability. If FBC does not have sufficient resources in place to meet overall customer power needs, unauthorized inadvertent power will flow from BC Hydro to FBC, and FBC must pay financial penalties to BC Hydro.

ii. How does FBC currently adjust load production from its facilities on the Kootenay River, in accord with overall customer power needs?

34.1. Please define an average unauthorized inadvertent power flow over the last ten years.

34.2. Please detail the financial penalties FBC would have to pay to BC Hydro in the event of an unauthorized inadvertent power flow.

34.2.1. Please provide context for the financial penalties in terms of the size of rate impact that would likely accrue as a result of unauthorized, inadvertent power flows.

34.3. Please confirm that unauthorized inadvertent power flow would occur automatically and that electrical service to FBC customers would not be affected in any way.

34.4. Is it the case that at any time that FBC does not have sufficient resources in place to meet overall customer power needs, anywhere on its system, that inadvertent power will flow from BC Hydro or other utilities on the interconnected grid to FBC? Please explain.

34.5. Please confirm that the only consequence to FBC in the case described above is a financial penalty.

34.6. If there are other consequences, please describe fully and provide quantification where applicable.

35. Reference: Exhibit B-3, BCOAPO 1.25.2, BCUC Order E-10-15, Appendix A pages 3 and 11

25.2 Please explain why "additional firm transmission cannot be reliably obtained on the U.S. side of the border".

Response:

Additional firm transmission cannot be reliably obtained on the U.S. side of the border because all of the long-term firm transmission rights have been acquired. However, U.S. transmission can generally be obtained through short-term non-firm reservations, when it is available, which can be used to deliver firm energy. For the most part, FBC has been able to secure non-firm transmission when required, although there have been times when no transmission was available. At this time, FBC has been able to mitigate this risk by entering into the Capacity and Energy Purchase and Sale Agreement with Powerex, as Powerex is a significant holder of firm transmission capacity from the U.S. to the B.C./U.S. border.

FBC describes the CEPSA as a master agreement in that it sets out the terms and conditions for future market transactions entered into by FBC with Powerex. Under the CEPSA, FBC will purchase all of its market energy requirements from Powerex and will sell any surplus capacity that may be available after meeting FBC's load requirements to Powerex. FBC states the benefits of this arrangement include increased certainty of energy access as well as surplus capacity sales at prices that are potentially better than could be achieved elsewhere, optimizing FBC's resource portfolio.[1]

3.1.3 The availability of supplies of the energy

FBC submits that while the CEPSA is not required in order for FBC to have access to market supply, the CEPSA increases FBC's ability to purchase energy based on market prices and is therefore expected to increase the overall reliability of FBC purchases of energy to serve load.[18] FBC states that:

> [T]ransmission from within the US to the border can be difficult at times to obtain and firm transmission rights are rarely available. Currently FBC's counterparties generally rely on the availability of non-firm transmission capacity to deliver to the border to serve FBC purchases.
>
> Under the Agreement, Powerex will be responsible for obtaining transmission capacity to deliver to the BC/US border to the degree it is necessary. FBC expects that Powerex will determine any transmission requirements to fulfill FBC's energy purchases as part of its market activities to support the optimisation of the BC Hydro system. As such it is expected that Powerex will be able to deliver energy purchases to the BC/US border or to the Kootenay Interconnection with a higher degree of certainty than FBC could achieve under its existing market arrangements, at comparable or lower cost.[19]

35.1. Please confirm the CEPSA is in place until 2018 and renewable annually thereafter until 2025.

35.1.1. If not confirmed, please provide the terms for the CEPSA and/or a copy of the agreement.

35.2. Please confirm that FBC will purchase all of its market energy requirements from Powerex under the CEPSA.

35.2.1. If not confirmed, please explain why not and clarify from where and how much energy FBC would be likely to purchase from alternative sources.

35.3. Please explain why the CEPSA was not mentioned in the LTERP application, particularly in sections 2.4.4 Regional market Opportunities, 8.2.4 Market Purchases, and Appendix J section 3.5 Market Purchases.

35.4. Please provide FBC's best estimate to quantify the higher degree of certainty referred to in the order (reference above).

35.5. What is the probability that, under the CEPSA agreement, FBC will be unable to access market power when it is needed for the period until 2025?

35.6. Under the CEPSA, is FBC able to access surplus power from BC Hydro in addition to or in place of PPA power? Please explain.

36. **Reference: British Columbia Hydro and Power Authority ~ F2017 to F2019 Revenue Requirements Application ~ Project No. 3698869 Exhibit B-15 CEC IRs 2.135.3; 2.145 and British Columbia Hydro and Power Authority ~Exhibit B-17, 2016 Rate Design Application Evidentiary Update; BC Hydro ~F2017 to F2019 Revenue Requirements Application~ B-1-1 page 1320 of 1571 Appendix X Demand Side Management Assumptions page 2**

2.135.3 Please provide the complete dataset for BC Hydro's surplus and deficit by year dating back to 1961, and include the value of market sales and market purchases for each year.

	1964	1965	---	---	2016	Total
Surplus (kwh)						
Market Sales (kWh)						
Market Sales $						
Deficit (kwh)						
Market Purchases (kwh)						
Market Purchases ($)						
Total Identify KWh						

RESPONSE:

The Transfer Price Agreement between BC Hydro and Powerex came into effect April 1, 2003, at the start of fiscal 2004. Prior to this date, electricity purchases and sales were not split between trade and domestic and as a result the information requested for before fiscal 2004 is not available. BC Hydro is providing the net annual surplus or deficit in a given fiscal year.

BC Hydro is not able to provide Total Identify (KWh) as part of this response, because we are not certain as to what the term refers to.

Fiscal Year	Energy Surplus[1] (GWh)	Market Electricity Sale Energy (Surplus Sales) (GWh)	Market Electricity Sale Revenue (MCAD)	Energy Deficit[1] (GWh)	Market Electricity Purchase Energy (GWh)	Market Electricity Purchase Cost (MCAD)
2004		0	0.0	5200	5349	270.0
2005		0	0.0	4000	6896	393.2
2006		0	0.0	4000	5853	351.1
2007		0	0.0	9000	5698	249.7
2008	1600	811	31.9		2258	153.3
2009		196	9.7	3500	5020	272.6
2010		0	0.0	6400	2161	80.5
2011		53	0.1	4600	3791	128.4
2012	5600	710	12.7		840	18.6
2013	5700	6020	80.2		359	10.1
2014		1008	36.7	1700	918	41.9
2015	5500	15	0.2		207	6.0
2016	3300	6277	174.1		122	2.8

1.32.3 What would be the RRA impact of reducing the excess of energy during the test period?

RESPONSE:

The amount of consolidated net energy generated in excess of the load forecast is estimated at 4,945 GWh in fiscal 2017, 4,928 GWh in fiscal 2018 and 3,524 GWh in fiscal 2019. BC Hydro expects to optimize the value of this energy by selling this energy into neighboring electricity markets and the estimated sales revenue is reflected in the revenue requirement calculation in the Application.

Table 3 Energy LRB After Planned Resources

Operating | Planning

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025
Existing and Committed Heritage Resources		46,936	46,164	46,226	48,671	48,671	48,671	48,671	48,671	48,671
Site C									386	2,435
Sub-total	(a)	46,535	46,024	46,226	48,671	48,671	48,671	48,671	49,058	53,106
Existing and Committed IPP Resources	(b)	13,919	14,735	14,506	16,272	15,945	15,358	13,335	12,086	12,319
Future Supply-Side Resources										
IPP Renewals		64	241	565	865	811	1,100	3,169	3,596	3,850
Standing Offer Program		75	168	270	306	500	811	721	932	943
North Coast Capacity Additions		0	0	[illegible]	0	0	154	154	154	154
Sub-total	(c)	159	406	648	1,072	1,311	1,073	4,043	4,572	4,947
Total Supply	(d) = a + b + c	61,012	61,198	61,264	65,946	65,900	65,965	66,949	67,326	70,372
Demand - Integrated System Total Gross Requirements										
2016 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,162	-65,432	-66,676	-67,843	-68,050	-69,650	-70,421
Expected LNG Load		-389	-355	-598	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000
Sub-total	(e)	-60,620	-62,221	-64,050	-67,452	-69,220	-70,413	-71,050	-72,650	-73,420
Demand Side Management & Other Measures										
SIM Theft Reduction		193	193	193	193	193	193	193	193	193
Voltage and VAR Optimization		111	200	220	237	266	269	302	307	312
2016 DSM Plan F15 and F16 savings		1,340	1,350	1,067	1,355	1,357	1,383	1,301	1,131	1,397
2016 DSM Plan F2017+ savings		630	1,289	1,788	2,406	2,958	3,315	3,814	4,153	4,474
Sub-total	(f)	2,276	3,072	3,064	4,212	4,735	5,276	5,701	6,054	6,325
		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025
Surplus / Deficit	(g) = d + e + f	**2,619**	**2,048**	**455**	**2,769**	**1,486**	**765**	**(205)**	**(276)**	**3,277**
Small Gap Surplus / Deficit		5,611	6,137	5,903	9,251	8,743	8,654	7,617	6,961	11,609
Large Gap Surplus / Deficit		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

(GWh)		F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Site C		5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	11,928	11,819	11,500	10,985	10,187	9,723	9,054	9,608	9,447
Future Supply-Side Resources										
IPP Renewals		4,171	4,255	4,447	4,650	5,581	6,048	6,093	6,141	6,302
Standing Offer Program		1,053	1,131	1,275	1,305	1,495	1,607	1,717	1,628	1,606
North Coast Capacity Additions		154	154	154	154	154	154	154	154	154
Sub-total	(c)	5,378	5,573	5,871	6,309	7,233	7,606	7,970	8,123	8,265
Total Supply	(d) = a + b + c	71,077	71,152	71,142	71,125	71,132	71,302	71,305	71,501	71,613
Demand - Integrated System Total Gross Requirements										
2016 Oct Mid Load Forecast Before DSM*		-71,440	-72,239	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,550
Expected LNG Load		-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(e)	-74,440	-75,239	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,550
Demand Side Management & Other Measures										
SIM Theft Reduction		193	193	193	193	193	193	193	193	193
Voltage and VAR Optimization		316	334	339	344	348	353	358	363	369
2016 DSM Plan F15 and F16 savings		1,242	1,107	1,103	1,072	1,021	1,003	1,018	1,016	1,006
2016 DSM Plan F2017+ savings		4,853	5,201	5,396	5,628	5,869	6,067	6,172	6,095	6,077
Sub-total	(f)	6,634	6,837	7,039	7,235	7,431	7,637	7,746	7,661	7,643
		F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Surplus / Deficit	(g) = d + e + f	**3,241**	**2,711**	**1,856**	**1,082**	**331**	**(447)**	**(1,370)**	**(2,372)**	**(3,034)**
Small Gap Surplus / Deficit		12,102	11,551	11,230	10,782	10,050	8,704	8,032	9,698	7,829
Large Gap Surplus / Deficit		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Market price of electricity: 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, updated with 2015 exchange rates, has a levelized value of approximately $36/MWh (F2016 $) over a 20-year period from F16 to F35.

36.1. Given that BC Hydro has been in a surplus energy position for 4 of the past 5 years, and is forecast to be in a surplus energy position for the next three years at least, and possibly up to 20 years or longer with the first Site C energy expected to come on line as planned in December 2023[1], please advise what efforts FBC has made to engage with BC Hydro to secure long term access to this clean electricity.

36.2. Please describe what options FBC may have to access to this surplus energy, besides the existing PPA.

36.3. Has FBC considered the possibility of meeting all of its energy and capacity needs over the LTERP period with surplus power from BC Hydro?

36.3.1. If yes, please provide FBC's views as to the possibility of meeting its energy and capacity needs with surplus power from BC Hydro.

36.3.2. If no, please explain why not.

36.4. Please provide BC Hydro's most recent Load Resource Balance.

36.5. Please comment on the likelihood that, when BC Hydro is in surplus, their cost value of energy will be in the range of market energy price.

36.6. Please provide BC Hydro's forecast of market energy prices for the next 20 years.

36.7. Please confirm that Mid C electricity prices are sensitive to natural gas prices, as one of the determinants of price. Please discuss other factors impacting future electricity prices.

36.8. Please provide the data and graphic for CME futures prices for natural gas at Henry Hub for the next 10 years.

[1] BC Hydro, Site C Clean Energy Project Quarterly progress Report No. 5 https://www.sitecproject.com/sites/default/files/quarterly-progress-report-no5-f2017-q2-july-september-2016.pdf

37. Reference: Exhibit B-5, CEC IR 5.1; 5.2

5. Reference: Exhibit B-1, page 53

> 3.2.1 Gross Load Forecast
>
> FBC's reference case load forecast anticipates a modest rate of load growth over the twenty-year planning horizon of the LTERP. The Company is forecasting an increase in gross load from 3,544 GWh in 2016 to 4,334 GWh by 2035, a compound annual growth rate of 1.1 percent.

5.1 Please provide FBC's Actual gross load, and the Actual growth rates for the last 30 years by customer class. Please break out data from the City of Kelowna to the extent that FBC has the data since purchase and as wholesale customer before purchase. Please provide the information both Before and After DSM.

Response:

FBC's actual historic load and growth rates by customer class are provided in Table 1 below. The City of Kelowna data has been broken out from the Wholesale class for the years 2001 to 2013. FBC is able to provide data for the former City of Kelowna electric utility for the period 2001 to 2013; after 2013 the former City of Kelowna customers are direct customers of FBC. The information provided in Table 2 below is after DSM since savings are embedded in the actual data.

Table 1: FBC Actual Data

FBC Actual Sales (GWh)										
Year	Residential	Commercial	Wholesale	Kelowna	Industrial	Lighting	Irrigation	Net Load	Losses	Gross Load
1986	721	294	663		280	14	42	2,014	263	2,277
1987	682	298	649		360	13	52	2,054	277	2,331
1988	740	319	695		417	13	45	2,229	281	2,510
1989	768	337	714		453	13	48	2,327	294	2,621
1990	813	352	740		459	14	34	2,412	324	2,736
1991	846	363	756		433	13	41	2,452	312	2,764
1992	850	378	765		426	13	45	2,480	308	2,788
1993	931	406	804		491	12	33	2,679	340	3,019
1994	889	400	814		558	12	44	2,526	413	2,939
1995	933	425	829		577	12	46	2,573	365	2,938
1996	1,004	465	876		313	12	42	2,711	351	3,062
1997	940	459	844		289	12	36	2,580	335	2,915
1998	938	483	837		263	12	48	2,581	304	2,885
1999	945	485	847		273	12	45	2,607	316	2,923
2000	978	498	873		279	12	43	2,683	310	2,993
2001	993	520	602	278	335	10	43	2,782	245	3,026
2002	1,008	524	587	291	363	10	54	2,838	336	3,174
2003	1,013	520	614	293	337	10	52	2,839	347	3,186
2004	1,016	539	619	300	348	10	42	2,875	355	3,230
2005	1,070	568	615	301	357	12	44	2,967	378	3,345
2006	1,049	616	657	314	348	13	43	3,041	364	3,405
2007	1,162	650	585	291	314	13	48	3,064	346	3,410
2008	1,224	661	610	314	218	13	46	3,087	313	3,400
2009	1,273	675	600	331	216	13	49	3,157	321	3,478
2010	1,216	660	571	309	234	14	40	3,044	280	3,324
2011	1,254	657	580	329	271	13	40	3,144	308	3,452
2012	1,224	681	566	331	291	13	38	3,143	271	3,414
2013	1,346	788	351	321	352	13	40	3,711	277	3,489
2014	1,304	866	573		381	16	40	3,178	271	3,450
2015	1,260	853	562		380	16	46	3,116	268	3,384

Table 2: FBC Actual Growth Rates (%)

FBC Actual Growth Rates (%)										
Year	Residential	Commercial	Wholesale	Kelowna	Industrial	Lighting	Irrigation	Net Load	Losses	Gross Load
1987	5.4%	1.4%	2.1%		28.6%	7.1%	23.8%	2.0%	5.3%	2.4%
1988	8.5%	7.0%	7.1%		15.8%	0.0%	13.5%	8.5%	1.4%	7.7%
1989	3.8%	5.6%	2.7%		9.1%	0.0%	11.1%	4.4%	4.6%	4.4%
1990	5.9%	4.4%	3.7%		0.8%	7.7%	15.0%	3.7%	10.2%	4.4%
1991	4.1%	3.1%	2.1%		5.7%	7.1%	20.6%	1.6%	3.7%	1.0%
1992	0.5%	4.2%	1.5%		1.6%	0.0%	9.8%	1.1%	1.3%	0.9%
1993	9.5%	8.1%	4.7%		15.2%	7.7%	26.7%	8.1%	10.4%	8.3%
1994	4.5%	2.3%	1.2%		25.1%	0.0%	33.3%	5.7%	21.5%	2.7%
1995	4.9%	6.5%	1.9%		11.1%	0.0%	4.5%	1.9%	11.8%	0.0%
1996	7.0%	9.2%	5.8%		4.4%	0.0%	8.7%	5.8%	3.8%	4.2%
1997	6.4%	1.1%	3.7%		7.5%	0.9%	14.3%	4.8%	4.6%	4.8%
1998	0.2%	5.1%	0.7%		9.2%	0.0%	33.3%	0.0%	9.3%	1.0%
1999	0.7%	0.4%	1.2%		4.0%	0.9%	6.3%	1.0%	3.9%	1.3%
2000	3.5%	2.7%	3.0%		2.0%	0.0%	4.4%	2.9%	1.9%	2.4%
2001	1.5%	4.4%	31.1%		20.2%	16.1%	0.0%	3.7%	21.1%	1.1%
2002	1.5%	0.8%	2.5%	4.2%	8.2%	1.7%	26.1%	2.0%	37.4%	4.9%
2003	0.5%	0.8%	4.7%	0.5%	7.3%	0.4%	4.5%	0.0%	2.3%	0.4%
2004	0.3%	3.7%	0.8%	2.4%	3.3%	0.3%	18.0%	1.3%	2.3%	1.4%
2005	5.3%	5.3%	0.7%	0.5%	2.7%	17.4%	3.6%	3.2%	6.5%	3.6%
2006	2.0%	8.5%	6.9%	4.3%	2.4%	4.9%	2.4%	2.5%	3.8%	1.8%
2007	10.8%	5.4%	11.0%	7.3%	9.8%	1.9%	12.7%	0.8%	5.0%	0.1%
2008	5.4%	1.7%	4.2%	7.8%	30.6%	4.5%	4.4%	0.8%	9.4%	0.3%
2009	3.9%	2.2%	1.6%	5.2%	1.0%	0.8%	5.9%	2.3%	2.5%	2.3%
2010	4.5%	2.3%	4.8%	6.5%	8.3%	8.9%	17.5%	3.6%	12.8%	4.4%
2011	3.1%	0.4%	1.5%	6.5%	15.9%	8.6%	0.1%	3.3%	10.0%	3.8%
2012	2.4%	3.6%	2.3%	0.4%	7.4%	1.9%	5.8%	0.0%	12.1%	1.1%
2013	10.0%	15.8%	38.1%	2.9%	21.2%	0.1%	4.4%	2.2%	2.5%	2.2%
2014	3.1%	9.8%	63.7%		8.1%	16.0%	0.8%	1.0%	2.2%	1.1%
2015	3.4%	1.5%	1.8%		0.3%	1.6%	14.9%	2.0%	1.3%	1.9%

Key
Not available
1995 Integrated Resource Plan
2005 Resource Plan
2009 Resource Plan
2012 Long Term Resource Plan

Table 1: Forecasts Before-DSM (GWh)

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	931	412	382	835		52	2,611	326	2,938	
1996	946	425	396	857		52	2,675	334	3,009	
1997	961	439	410	879	Included	52	2,741	343	3,083	
1998	976	453	426	902	with	52	2,808	351	3,159	
1999	992	467	441	925	irrigation	52	2,877	360	3,237	
2000	1,008	482	458	950		52	2,949	369	3,317	
2001	1,024	497	475	974		52	3,022	378	3,400	
2002	1,040	513	492	1,000		52	3,097	387	3,484	
2003	1,057	530	510	1,026		52	3,174	397	3,571	
2004	1,074	547	529	1,052		52	3,254	407	3,660	
2005	1,055	549	323	960	10	47	2,945	366	3,311	
2006	1,070	562	360	978	10	47	3,028	336	3,364	
2007	1,082	573	363	992	10	47	3,068	340	3,409	
2008	1,093	582	367	1,005	10	47	3,104	344	3,449	
2009	1,228	685	227	929	14	48	3,130	298	3,426	
2010	1,250	701	230	936	14	48	3,179	303	3,480	
2011	1,273	722	234	943	14	48	3,232	308	3,538	CoK
2012	1,282	708	253	601	15	45	3,241	314	3,555	337
2013	1,306	728	261	615	15	45	3,312	321	3,632	341
2014	1,332	746	266	627	16	45	3,377	327	3,703	345
2015	1,359	763	269	637	16	45	3,436	333	3,769	348
2016	1,385	776	259	646	17	45	3,479	337	3,816	352
2017	1,411	790	251	653	17	45	3,522	341	3,863	356

Table 3: Forecasts After-DSM (GWh)

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	1,222	678	224	921	14	48	3,107	296	3,401	
2010	1,243	695	226	927	14	48	3,154	301	3,453	
2011	1,266	715	231	934	14	48	3,207	306	3,511	CoK
2012	1,264	696	250	593	14	44	3,193	309	3,502	333
2013	1,276	709	255	602	14	43	3,233	310	3,543	334
2014	1,290	719	258	608	13	43	3,266	311	3,577	334
2015	1,301	727	258	613	13	42	3,289	310	3,599	335
2016	1,312	732	245	615	13	41	3,293	308	3,601	335
2017	1,328	737	235	618	13	41	3,307	307	3,614	336

Note: Because DSM is calculated for Wholesale loads and not on an individual Wholesale customer basis, the after-DSM CoK load has been based on an estimated allocation of the CoK percentage of Wholesale load for the 2012 LTRP after-DSM forecast.

Table 4: Forecast Growth Rates After-DSM

Year	Res	Comm	Ind	Whsle	Lighting	Irrigation	Net	Losses	Gross	
1995	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1999	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2000	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2010	1.7%	2.5%	1.8%	0.7%	0.0%	0.0%	1.5%	1.7%	1.5%	
2011	1.9%	2.9%	1.3%	0.8%	0.0%	0.0%	1.7%	1.7%	1.7%	
2012	-0.2%	-2.7%	8.2%	-36.5%	0.0%	-8.3%	-0.4%	1.0%	-0.3%	CoK
2013	0.9%	1.9%	2.0%	1.5%	0.0%	-2.3%	1.3%	0.3%	1.2%	1.1%
2014	1.1%	1.4%	1.2%	1.0%	-7.1%	0.0%	1.0%	0.3%	1.0%	1.1%
2015	0.9%	1.1%	0.0%	0.8%	0.0%	-2.3%	0.7%	-0.3%	0.6%	1.1%
2016	0.8%	0.7%	-5.0%	0.3%	0.0%	-2.4%	0.1%	-0.6%	0.1%	1.1%
2017	1.2%	0.7%	-4.1%	0.5%	0.0%	0.0%	0.4%	-0.3%	0.4%	1.1%

37.1. Please indicate whether or not the above actuals data are weather normalized and if not, please supply weather normalized data.

37.2. Please confirm that Demand Side Management savings were not forecast in the 1995 Integrated Resource Plan, nor the 2005 Resource Plan and that this is the reason why these forecasts are not available prior to 2010.

37.2.1. If not confirmed, please explain why the Forecasts and Forecast Growth Rates after DSM are not available before 2010.

37.3. A comparison of the data for the period 2006 – 2015 shows that changes in gross load over this 10 year period were negative (-1%) and total increases in Net load were relatively small (2.5%). In contrast forecast load growth over the same period (Using before DSM figures for 2006 and 2007, and after DSM figures for the period between 2008 and 2015) is 7%. Please provide FBC's views as to ratepayer impacts of this over-forecasting.

37.3.1. Please quantify the ratepayer impacts over this period.

37.4. Please quantify the impact of a 1% annual over-forecast over a 20 year period.

37.5. Please confirm that consistent over-forecasting could be reasonably expected to lead to an over-acquisition of supply for a period of time.

37.5.1. If not confirmed, please explain why not.

37.6. Please confirm that consistent over-forecasting can result in an under-collection of revenues from customers, and lower than necessary rates for a period of time.

37.6.1. If not confirmed, please explain why not.

37.7. Please confirm that price increases can reasonably be expected to result, to some extent, in reduced demand.

37.7.1. If not confirmed, please explain why not.

37.7.2. Please provide FBC's estimate of price elasticity for each rate class.

38. **Reference: The CEC wishes to understand the historical relationship between FBC's forecasting and the Actual Total Gross Requirements. To the extent that the above information does not represent FBC's complete dataset of forecasts, please provide the full dataset of the FBC annual 10 year forecasts for each year starting in 1986 through 2017, after DSM, and the Actual as shown in the example table below.**

	Forecast year	1986 GWh	1987 GWh	.... GWh	.... GWh	.... GWh	2035 GWh
Forecast vintage							
1986							
1987							
....							
2017							
Actual total gross requirement							

39. **Reference: British Columbia Hydro and Power Authority ~ F2017 to F2019 Revenue Requirements Application ~ Project No. 3698869 Exhibit B-15, CEC IR 2.140.2**

2.140.2 If BC Hydro is over-forecasting it would be reasonable to expect that this could create over-acquisition of supply and a greater cost to ratepayers than may be needed. Please discuss.

RESPONSE:

If BC Hydro was over-forecasting its energy needs, then during a specific test period the forecasted Cost of Energy may be greater than what will actually be used. However, BC Hydro's energy deferral accounts ensure that only the actual costs of energy are ultimately recovered in rates from our customers, as any excess of forecasted energy costs over actual energy costs would be a credit to the energy deferral accounts.

39.1. Does FBC maintain deferral account(s) to capture any excess of forecasted energy costs over actual energy costs? If yes, please identify and provide the historical balance over the last 20 years.

40. **Reference: Exhibit B-5, CEC IR 32.1**

32. Reference: Exhibit B-1, Volume 2 Long Term DSM Plan page 14

The following Table 3-1 shows key DSM scenario data including the percentage of forecast load growth to be offset by DSM and the sum total of DSM savings to be targeted over the planning horizon. For context, of the total (2016 to 2035) annual savings, FBC has booked 511 GWh of DSM program savings from program inception in 1989 to 2015 inclusive.

Table 3-1: Key DSM Scenario Data

Category	DSM Scenario			
	Low	Base	High	Max
Annual Savings, GWh				
Average per annum ('18-'35)	20	26	31	36
% of load growth ('18-'35)	50%	66%	77%	90%
Total (2016 to 2035)	407	523	602	686
Resource Cost, 2016 $/MWh				
Incremental cost incl. program costs	$45	$88	$104	$114

32.1 Please provide total DSM program historical performance for each of the last ten years by rate class:

- Annual savings, GWh planned and actual
- Resource costs $/MWh planned and actual
- Customer participation planned and actual
- Please break out data from Kelowna

Response:

The requested information is not available by rate class, but is filed historically by major customer sector: Residential, Commercial, and Industrial. The data for annual savings and resource costs by customer sector is contained in the table below.

		Approved Annual Energy Savings	Actual Annual Energy Savings	Plan Levelized Cost[1]	Actual Levelized Cost
Year	Sector	(GWh)		($/MWh)	
2007	Residential	10.6	15.3		19
	Commercial	9.2	10.4		20
	Industrial	2.0	2.2		21
	Total	21.8	27.9		21
2008	Residential	8.4	12.9		26
	Commercial	9.1	11.0		20
	Industrial	2.0	3.3		30
	Total	19.5	27.3		23
2009	Residential	10.7	9.3		31
	Commercial	11.6	16.4		18
	Industrial	3.0	2.7		22
	Total	25.3	28.4		23
2010	Residential	12.1	11.6		28
	Commercial	12.1	14.7		20
	Industrial	3.4	3.0		19
	Total	27.5	29.3		23
2011	Residential	16.4	11.4		42
	Commercial	13.9	24.2		27
	Industrial	9.4	0.8		21
	Total	39.7	36.3		34
2012	Residential	16.1	12.8		64
	Commercial	13.4	17.9		37
	Industrial	2.5	0.9		45
	Total	32.0	31.6		51
2013	Residential	16.9	16.2		67
	Commercial	12.0	10.9		53
	Industrial	2.6	2.5		96
	Total	31.5	29.6		67
2014	Residential	5.8	8.7	16.0	52
	Commercial	6.2	5.3	17.0	57
	Industrial	0.8	0.6	12.4	78
	Total	12.8	14.6	21.0	55
2015	Residential	12.1	5.6	30.7	40
	Commercial	12.5	5.9	25.7	67
	Industrial	1.5	1.1	19.7	57
	Total	26.2	12.6	34.0	60
2016	Residential	12.9	12.5	30.7	75
	Commercial	12.7	8.1	25.7	81
	Industrial	1.6	2.1	19.7	16
	Total	27.2	22.8	34.0	51

[1] Levelized costs were not submitted on a plan basis prior to 2014.

40.1. Why did FBC did not submit levelized costs on a plan basis prior to 2014?

40.2. Please provide any data FBC has on DSM plan costs (in $/MWh) that were not submitted in the above table.

40.3. For the three years for which planned costs were provided, cost per MWh has been significantly higher than planned; 2014 162% higher, 2015 76% higher and 2016 50% higher.

40.3.1. Why have the actual costs been so much higher than planned.

40.3.2. How will FBC ensure that the cost of future years' DSM programs will be as planned?

40.4. For the last two years actual energy savings were significantly less than approved. How will FBC ensure that in future years planned and approved energy savings will be achieved by its DSM program?

40.4.1. Why were the actual savings so much lower than planned?

40.5. Has FBC done any analysis of DSM performance vs plan? If so, please provide any reports or analysis.