FINAL SUBMISSION ON BEHALF OF

THE CLEAN ENERGY ASSOCIATION OF BRITISH COLUMBIA ("CEBC")

Re: BRITISH COLUMBIA HYDRO and POWER AUTHORITY

("BCH" or "BC Hydro")

F2017-F2019 Revenue Requirements Application

("F17-19 RRA" or "Application")

Project No. 3698869

June 13, 2017

British Columbia Hydro

F2017-F2019 Revenue Requirements Application

INTRODUCTION

With respect to its need for ever increasing electricity rates, BC Hydro is caught in a "perfect storm" of competing economic pressures, caused by:

- The huge growth of its capital investment, simply to maintain the safety and reliability of the existing infrastructure; and
- The lack of any increase (and even a slight decline) in the amount of domestic load being served over the past decade, and the likelihood that this will continue for the next decade.

This stagnation, and even decline in the load is due to a combination of many factors occurring coincidently, including:

- A prolonged slowdown in the world economy, affecting many key B.C. resource industries;
- The development of new cost-effective energy efficient technologies;
- The success of DSM programs, combined with changes in government regulations which promote energy efficiency;
- The natural consumer price response to significant increases in electricity prices; and
- The absence of any aggressive programs encouraging the electrification of new loads.

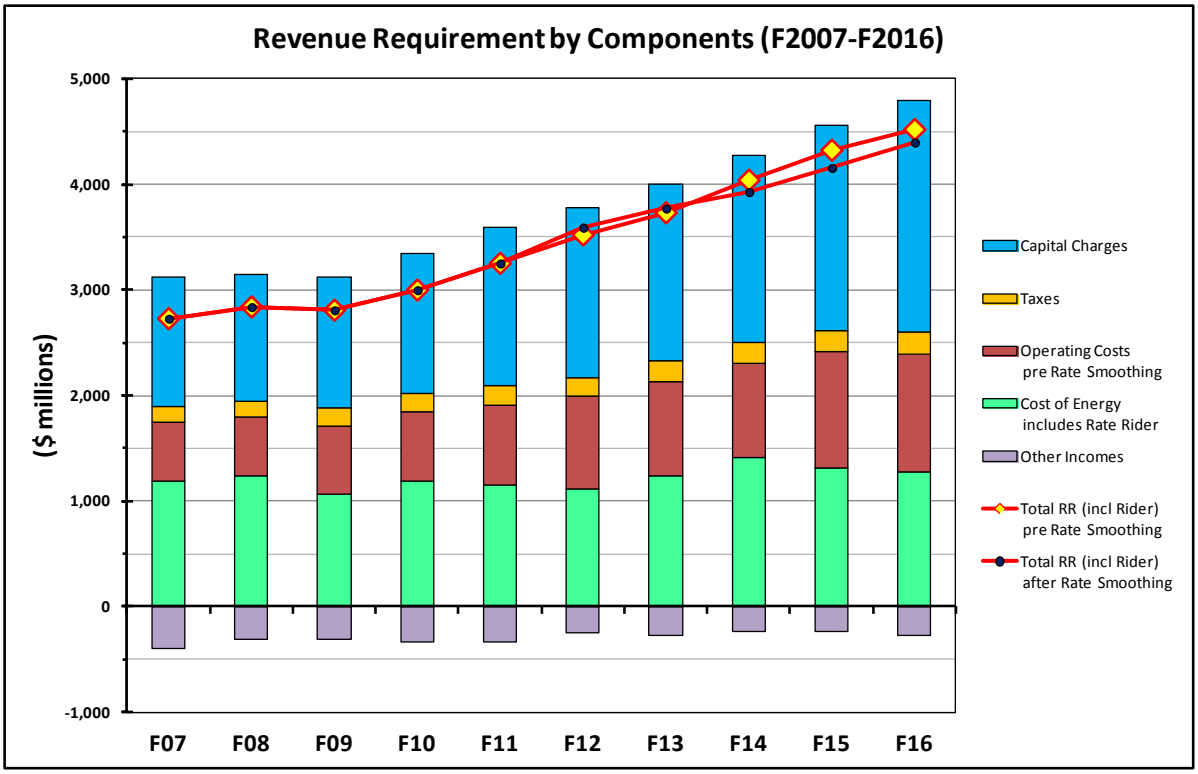
Whatever the reasons for the stagnation of load growth, when it is combined with the huge increase in BC Hydro's capital investment, these two factors become the primary drivers of the significant rate increases seen by BC Hydro's ratepayers over the past decade, and those which will occur over the next decade.

The CEBC's comments will be set out under the following major headings:

1. Analysis of BC Hydro's increasing revenue requirements since F2007
2. Analysis of BC Hydro's domestic energy deliveries since F2007
3. The key drivers in BC Hydro's increasing electricity rates
4. The downside of increasing Demand Side Management ("DSM")
5. The need for an aggressive program of low-carbon electrification
6. The strongest and most immediate electrification opportunities
7. Can BC Hydro's capital investment program be re-prioritized?

1. BC HYDRO'S INCREASING REVENUE REQUIREMENT SINCE F2007

Based on the historical data given in BC Hydro's F2017-2019 Revenue Requirements Application[1] (the "F17-19 RRA") CEBC has compiled the following chart showing the increases in the revenue requirements broken down by components, for the period from F2007 to F2016.



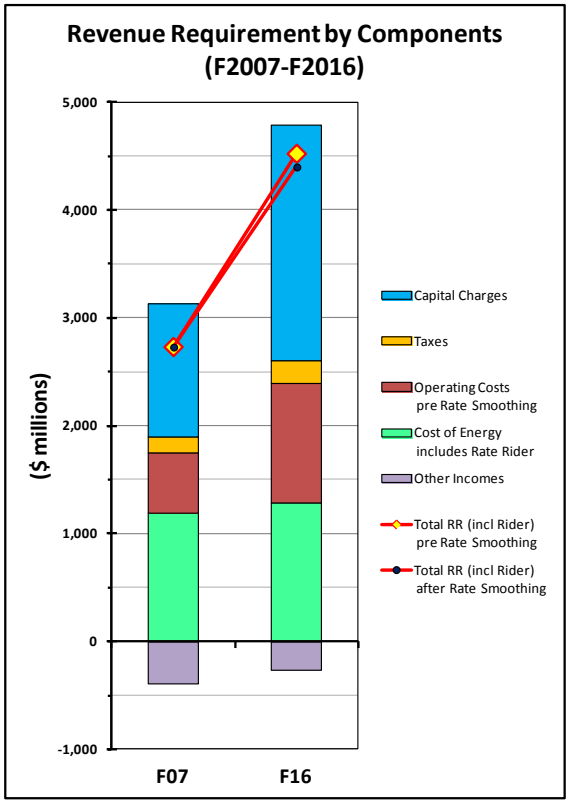
When comparing the revenue requirement for F2016 to that for F2007, several observations can be made:

1. The overall increase from $2.7 billion to $4.5 billion amounts to 66% over this period.
2. The largest single contribution to the increases comes from the capital-based charges (which include depreciation/amortization, financing charges, and net income), which together have increased by $955 million, or 78% since F2007.
3. The 2nd largest contribution to the increases comes from BC Hydro's operating costs (which here are taken before the deduction of the Rate Smoothing deferral amounts). These have increased by $550 million, or 99% since F2007.
4. 3rd in its impact on the total increases, is the reduction in other incomes (mostly Powerex), which have declined by $127 million, or 32% since F2007.

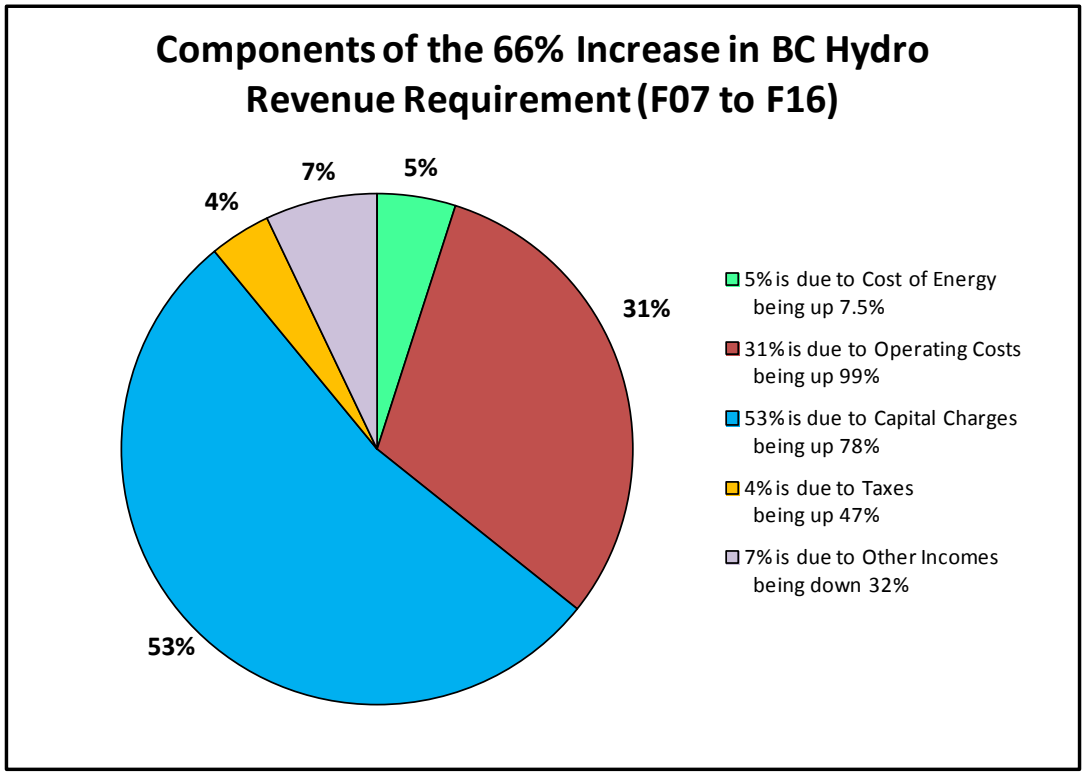
[1] Chart data extracted from Exhibit B-1-1, Appendix A, Schedule 3.0, costs on a current view basis

5. The remaining contributions to the increases come from the cost of energy (up $88 million, or 7.5%), and from taxes (up $69 million, or 47%). The cost of energy includes the cost of energy purchased from independent power producers.

The relative magnitude of these contributions can be seen most readily by comparing the F2007 and F2016 years directly, as in the following chart:



And the relative impact of the different components on the total increase can be seen in the following pie chart:



From this pie chart, it is clear that the capital-based charges dominate the increases since F2007, making up more than half of the total increases during the period. When the increases in capital-based charges and operating costs are combined, they account for 84% of the total of $1.8 billion in increases since F2007.

The lowest rate of increase from all the components comes from the cost of energy, which has only increased by 7.5% over the period, and only accounts for 5% of the total increases.

The increase in taxes (up 47%) and the decline of other incomes mainly Powerex (down 32%) are far more dramatic, proportionally, than the cost of energy, and together account for 11% of the total increases.

Conclusions

It has been a popular misconception that the dramatic rise in BC Hydro's electricity rates over the past decade was primarily due to large increases in the cost of purchased energy.

The above analysis shows clearly that the increasing cost of energy is a relatively minor factor, accounting for only a 3.3% increase, out of the total 66% increase in the revenue requirements over the period**.** In fact, the cost of energy has experienced the lowest rate of increase of any of the components, having increased by only 7.5% over the 10-year period, much less than the rate of inflation.

The financial history over the past decade reveals that 84% of the 66% increase (that is to say a 55% increase) is due solely to two factors:

1. The capital-based charges (for depreciation/amortization, financing costs, and net income) have increased by 78% over the period, and are the single greatest contributor to the total cost increases, accounting for more than one-half of the total increase in revenue requirement.

2. BC Hydro's own internal Operating Costs have doubled over the past 10 years (up 99% since F2007), accounting for 31% of the total increase in Revenue Requirement.

The remainder of the 66% total increase is due to rising taxes (up 47% since F2007) and a decline in Other Incomes (down 32%, mainly due to a fall in Powerex's trading margins).

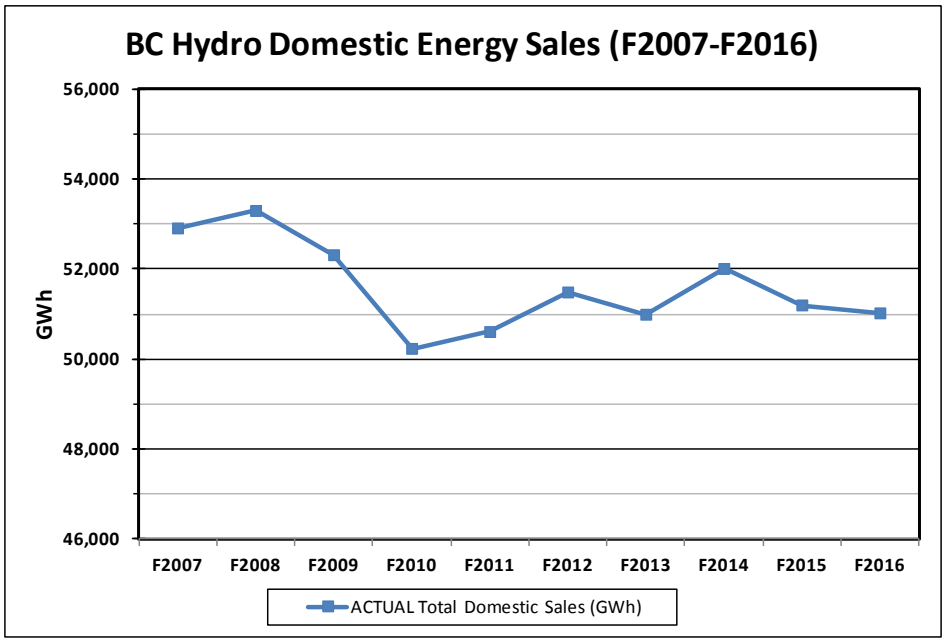
The fact that capital-based charges are the dominant driver of BC Hydro's increasing revenue requirement should be quite understandable when we realize that BC Hydro has been spending approximately $2 billion per year on rebuilding and refurbishing its capital assets over the past decade, and plans to continue this rate of spending over the next decade.

It should also be noted that the 78% rise in capital-based charges has occurred in spite of a significantly lower interest rate environment in F2016 than in F2007. Should interest rates return to F2007 levels, the impact on electricity rates can be expected to be greatly amplified by the now much higher levels of debt as a result of the decade-long capital spending program.

2. BC HYDRO'S DOMESTIC ENERGY SALES SINCE F2007

Even though BC Hydro's revenue requirement has risen by 66% over the past decade, this need has not necessarily given rise to a corresponding 66% increase in electricity rates. The increase in the revenue requirement is only one element in the "perfect storm" that leads to ever increasing rates.

In fact, there could have been no increase in electricity rates at all, if the domestic load had increased at the same rate as the revenue requirement. However, quite the opposite has actually occurred. The domestic load has remained static, and even declined slightly, as shown in the following chart:[2]



[2] Chart data extracted from Exhibit B-1-1, Appendix A, Schedule 14, line 10

The fact that the domestic load has declined by approximately 4%, at the same time as the revenue requirement has gone up by 66%, only makes matters worse for the rate increases on a per MWh basis. Consequently, the average revenue requirement per MWh of domestic load has risen by 72% over the 10-year period (from $52/MWh to $89/MWh).

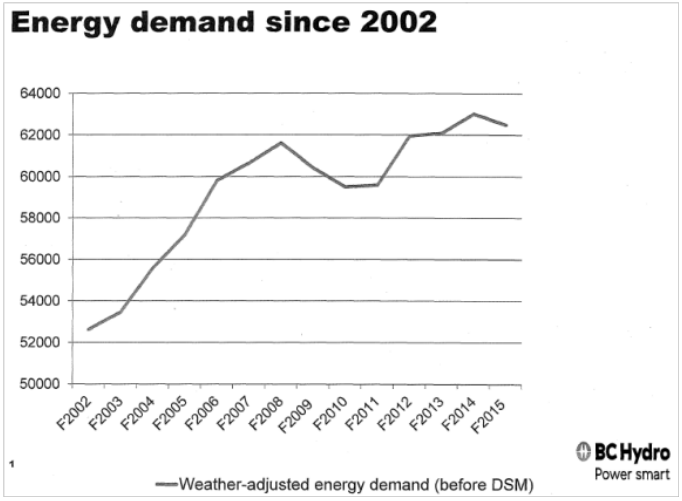
In terms of a "perfect storm," there are many potential factors that could have combined to cause the observed decline in the domestic load. CEBC cites the following examples:

1. The general downturn in world economies that occurred in 2009/10, and which continues to affect many of BC's commodity based industries.
2. The development of new cost-effective energy efficient technologies.
3. The success of BC Hydro's DSM programs, combined with changes in government regulations which promote energy efficiency (Over the past 10 years, BC Hydro has spent almost $1.2 billion on DSM[3], virtually all of which has been reported as successfully meeting its expectations for the reduction of electricity demand.)
4. The natural consumer price response to significant increases in electricity prices. As observed, BC Hydro's electricity prices have been steadily increasing. Since 2007 the average prices are up over 70% (and if referenced to 2002, the current rates are more than double). In the face of such increases (and with the further expectation of such increases continuing) it is not surprising that consumer demand should decline

An in-depth discussion of factors 1 and 2 is probably beyond the scope of this RRA proceeding, other than to list them among the potential factors that would logically lead to a decline of demand. However, CEBC will provide some comments on items 3 and 4.

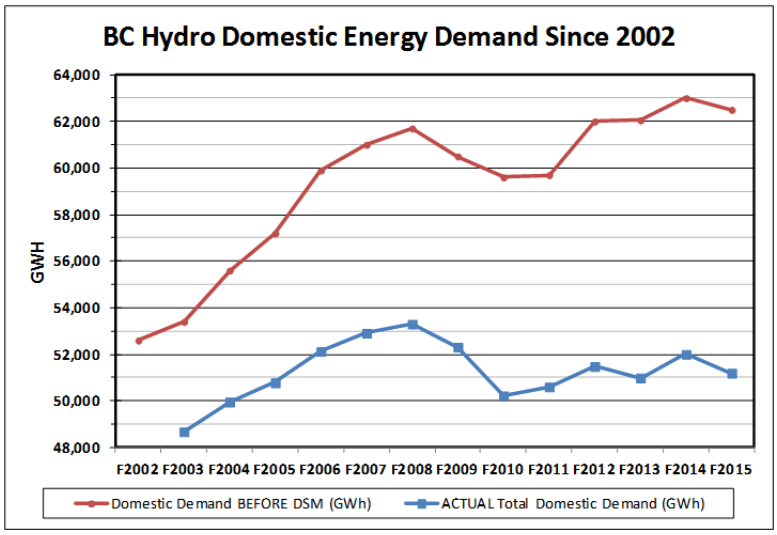
2.1 The Success of Demand Side Management

In its "*Site C Update*" Press Briefing, December 12, 2016, BC Hydro presented the following chart depicting "*Energy Demand since 2002*":



[3] Ibid. Schedule 2.2, the sum of additions to the DSM Regulatory Account is $1,182 million over the period.

CEBC noted that this depiction of BC Hydro's domestic energy demand was markedly different from that presented in the RRA. When the two depictions of demand are presented on the same chart, the difference is clearly apparent:[4]



CEBC concluded that, as per the chart footnote, the difference was primarily due to the impact of DSM programs. However this impression was corrected in BC Hydro's Rebuttal Evidence,[5] as BC Hydro pointed out that system losses were also a major factor in the difference.

CEBC asked for further clarification as to the amount of system losses vs. the amount of DSM savings, and BC Hydro provided the following data:[6]

GWh (per IR 3.45.1)	F2002	F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015
Losses	4,780	4,299	4,778	4,642	5,167	5,138	5,722	5,345	5,100	4,502	5,673	5,448	5,444	4,286
Own Use	61	59	64	99	100	91	93	79	65	60	61	73	76	72
Total Losses + Own Use	4,841	4,358	4,842	4,741	5,267	5,229	5,815	5,424	5,165	4,562	5,734	5,521	5,520	4,358
PowerSmart 2	133	358	739	1,281	1,921	2,501	2,501	2,501	2,496	2,401	2,231	2,015	1,779	1,486
PowerSmart 3	0	0	0	0	0	0	724	1,346	1,705	2,243	3,293	3,810	3,971	4,353
Total P/S 2 + 3	133	358	739	1,281	1,921	2,501	3,225	3,847	4,201	4,644	5,524	5,825	5,750	5,839
Total Losses + PowerSmart	4,974	4,716	5,581	6,022	7,188	7,730	9,040	9,271	9,366	9,206	11,258	11,346	11,270	10,197

The combined impact of losses (including system use) and DSM (programs 2 and 3) together account for approximately 98%[7] of the difference between the two lines on the previous chart, and give an indication of the extent to which DSM programs have contributed to the softening, and even reduction, in consumer demand over the past 15 years.

[4] Exhibit C4-7, CEBC IR 1.0 to BCSEA

[5] Exhibit B-20, BCH Rebuttal Evidence, page 14, Extent of Demand Side Management Savings Achieved

[6] Exhibit B-22, BCH response to CEBC IR 3.45.1

[7] The balance being accounted for by adjustments for billed vs. accrued sales and Non-Integrated requirements

However, with all of the difference between the two lines apparently accounted for, the one thing that appears to be missing from the picture is any amount attributed to the simple fact of the consumers' response to the significant price increases over the period. There is a small amount provided for within the DSM savings, but it appears far smaller than it might actually be.

2.2 The Natural Consumer Price Response

Of the amounts shown for DSM savings in the immediately above table, small amounts (ranging from 7% to 13% of the total DSM savings each year), have been included in each year and described as "*Savings from Conservation Rate Structure*".[8] These represent the impact of BC Hydro's assumed -0.05 price elasticity coefficient with respect to its conservation rate structures for residential and industrial customers.

Total Losses + PowerSmart	**4,974**	**4,716**	**5,581**	**6,022**	**7,188**	**7,730**	**9,040**	**9,271**	**9,366**	**9,206**	**11,258**	**11,346**	**11,270**	**10,197**
Rate Structure Savings	**0**	**0**	**0**	**0**	**0**	**0**	**232**	**474**	**501**	**616**	**717**	**727**	**590**	**571**
% of Total P/S Savings	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.2%	12.3%	11.9%	13.3%	13.0%	12.5%	10.3%	9.8%

Clearly BC Hydro is assigning a very small amount of the demand reduction to the effect of customer price elasticity. It does this by assuming a relatively low elasticity coefficient (-0.05) and by calculating the savings only with respect to the Tier 2 Residential and the Tier 2 Industrial sales ("Conservation Rates").

If a higher elasticity coefficient were used, and the responses of all customers included, it is quite possible that a great deal more of the demand reduction would have been attributed to the natural consumer response to the significantly rising prices of the past 15 years. (Increases have been over 70% in the past 10 years and over 100% in the past 15 years.)

In fact, a number of research studies have indicated that long-run elasticity coefficients were much higher than BC Hydro's assumed -0.05. CEBC presented the following list of research studies to BC Hydro and requested its comments:[9]

[8] Exhibit B-22, BCH response to CEBC IR 3.45.2

[9] Exhibit B-22, BCH response to CEBC IR 3.46.1

The response from BC Hydro simply fell back on the fact that its current assumption had been previously accepted:

> *"BC Hydro has reviewed the studies cited in the table above, but cannot comment on the specific methodologies, data and other assumptions used in the models used to estimate price elasticity.*
>
> *BC Hydro's assumption of -0.05 is based on the direct testimony of Dr. Ren Orans as contained in our 2008 Long-term Acquisition Plan (LTAP) Application to the BCUC.*
>
> *…Adopting Dr. Orans recommendations simplifies BC Hydro's previous process that used short- and long-term price elasticities which avoids double counting of rate-induced conservation and codes and standards and demand-side management program-induced conservation. This evidence was tested through responses to Information Requests and cross examination. The BCUC accepted BC Hydro's load forecast and methodology for the purpose of its review of the 2008 LTAP.*
>
> *Dr. Orans' direct testimony states -0.05 is within the range of 0.0 to -0.28, which comes from four papers cited in his evidence that studied residential price elasticity in winter peaking, low cost jurisdictions that are comparable to BC Hydro."*

BC Hydro appears to have established its assumption of a -0.05 elasticity coefficient based on analyses done prior to the 2008 Long Term Acquisition Plan (LTAP), at a time before there were significant price increases and before Conservation Rates even existed. It then appears to have sought confirmation from Dr. Orans that this coefficient was within an acceptable range, based on Dr. Orans review of four papers about earlier analyses done in similar jurisdictions. CEBC believes that it is probably time to review and renew that analysis in today's context.

It may have been a simplification from prior methods, but that does not necessarily mean it is the proper method going forward, now that times have changed and electricity rate increases appear to be a permanent fixture in our future.

This can be potentially an extremely important matter both for load forecasting and for the proper evaluation of DSM measures. If the proper elasticity coefficient should actually be a much greater number than -0.05 then much more of the decline in demand would be attributed to the consumers' response to the 100% price increases.

The long-run elasticity coefficients found by the studies cited in the table above had averages of -0.40 for residential and industrial customers and -0.29 for commercial customers. If a coefficient of even -0.20 were applied to BC Hydro's long-run rate increases of 100%, then that could account for a 20% decline in demand – which would be more than 10,000 GWh/year and great enough to account for all of the observed decline that BC Hydro has experienced since 2007. In other words, all of that decline in demand could be due solely to the consumers' response to the price increases.

Furthermore, if almost all of this demand decline would be attributed to consumer price response then, consequently, there would be almost none of the decline that would be attributed to the $1.2 billion in DSM program spending.

Such a shift in attributing the cause of the demand decline would have a profound impact on how the DSM benefit/Cost ratios were calculated. In fact, from this one simple reassignment of the cause of demand decline, the benefit cost tests could all become less than 1.0, indicating the programs were not really cost-effective from any perspective.

It is these apparently attractive benefit cost test ratios that appear to be driving a desire by some parties for an even greater expenditure on conservation programs.[10] However, those apparently attractive benefit cost ratios might need to be revised and recalculated at much lower values. In particularly they could become less than 1.0 (especially if the market price basis is used for evaluating the avoided cost of energy saved, rather than the long run marginal cost basis).

In light of the importance of this matter to both the load forecast and the proper evaluation of DSM expenditures, CEBC recommends that the BCUC direct BC Hydro to undertake a reevaluation of its elasticity assumptions.

It would be very helpful if the review is undertaken with "fresh eyes" and the CEBC suggests that one of the research groups listed in Table 2 should be commissioned to do this reevaluation.

2.3 The Absence of Aggressive Electrification

Up to this point in time, BC Hydro's DSM efforts have been primarily focused on reducing the demand for electrical energy. Only with the enactment of the recent Order in Councils No.100 and No.101[11] has BC Hydro stated its intention to pursue programs aimed at low-carbon electrification, consistent with the Government's Climate Leadership Plan.

Finally, the Government is coming around to the realization that DSM does not have to mean exclusively the reduction of demand. It can also mean the management of demand to achieve other objectives – for instance, the reduction of GHGs. It could even mean, perhaps, the selective development of new industries – which is what was done with the new electrical infrastructure built in the 1960s and 1970s.

3. THE DOWNSIDE OF INCREASING DEMAND SIDE MANAGEMENT

BC Hydro now finds itself in this "perfect storm" of rising fixed costs combined with stagnant, even falling demand. The fixed costs are rising predominantly because of the need to spend large amounts of capital to renew and rebuild its asset base. But along with the steadily rising costs a number of factors align to cause a decline in demand, which only serves to make the rate increases even greater, which in turn accelerates the decline in demand.

Then, in the context of this rising cost environment, BC Hydro has compounded its problem by spending another $1.2 billion on Demand Side programs that have been deemed to be successful.

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[10] In Exhibit C1-8, Mr. Grevatt, consultant for BCSEA-SCBC, frequently cited the benefit/cost ratios as indicators that additional DSM should be undertaken because it would reduce BCH's revenue requirement.

[11] Exhibit B-18 provides copies of the two OICs, which were both approved March 1, 2017

The cost effectiveness of DSM measures is founded on the premise that the utility can save at least the avoided cost of new generation, (often referred to as the long run marginal cost, or LRMC), and also that that avoided cost is greater than the cost of implementing the measures. However, there are a number of situations in which that presumption is merely an illusion.

At best, the saving of the LRMC is only a hypothetical saving. It means the utility can hypothetically reduce its costs relative to what those costs would have been if, at some time in the future, the utility would have had to acquire new energy and that energy would have been expensive. This hypothetical saving does not represent a real saving to current customers relative to what they are currently paying. So the customers don't actually recognize any saving at all because they have never seen, and may never seen, those hypothetical higher rates that might have occurred, but did not.

Once a situation of flat demand is reached – whether as a result of the success of previous DSM measures, or merely as the result of customer response to the price increases then any further savings do not avoid new generation, but only cause additional market sales. And these market sales have been at far lower prices than the LRMC.

In this situation of flat demand, it makes little sense to continue to try to reduce demand further, when most of the costs are fixed costs, which will not be reduced.

A further problem with the hypothetical savings from DSM measures comes from the fact that none of the commonly used evaluation metrics take into account the utility's lost billing revenue. Neither the Total Resource Cost test nor the Utility Cost test take the lost billing revenues into account. In BC Hydro's case, every time residential customers reduce their demand, they stop paying their share of the fixed costs on those MWh, and those fixed costs have to be transferred to the other customers. If the reduced demand is in Residential Inclining Block Tier 2, they may stop paying $0.12 for every kWh they save, but the utility will only recoup the marginal sales revenue, which is only about $0.04. Even if the utility is able to reduce its costs by the amount of the LRMC, that LRMC is now less than the revenue that is lost when the customer reduces his demand. And, on top of the lost billing revenue, there is still the cost of implementing the DSM programs, which must also be paid by all the remaining customers.

Accordingly, given BC Hydro's current state of depressed demand, CEBC recommends against spending hundreds of millions of dollars on new programs intended to depress the demand even further. These expenditures are both unnecessary, and unhelpful. Unnecessary, because the increasing prices have already accomplished the job of reducing demand, and unhelpful, because the additional expenditures will only further exacerbate the rate increases.

4. THE NEED FOR AGGRESSIVE LOW-CARBON ELECTRIFICATION

CEBC has shown that the matter of continuous rate increases is due to a "*perfect storm*" of different factors, the combination of which leads to a situation of lagging demand chasing ever-increasing fixed costs.

One of the ways out of this dilemma is to encourage new electrical loads that can carry their share of the rising fixed costs.

However, the concern with new electrical loads has always been that providing the new energy to serve them may be too costly.

Fortunately, the costs of new clean, green, renewable, non-emitting, energy resources, such as wind and solar power, have been dropping dramatically in recent years and B.C. has an abundance of all of them.

The incremental cost of new energy is now well within the range of the cost of the existing energy. BC Hydro is already at the point where the average revenue requirement per MWh has reached $89 (F2016, when the 'real' underlying cost is considered, prior to the mitigating effect of the Rate Smoothing deferral). That average will be approaching $100/MWh by the end of the test period for this Application.

Also, and fortunately, BC Hydro's system is ideally suited to being able to smoothly integrate large quantities of variable renewable energy. The generation assets have the needed storage, capacity and ramping capabilities. Thanks to BC Hydro's aggressive capital refurbishment program, most of the backbone of the transmission system has already been, and continues to be, upgraded to be able to add a variety of new loads with a minimum of new investment. (Any new investment that is needed is generally charged to the connector, at any rate.)

BC Hydro's biggest operational problem comes from the 'freshet' surge in the spring of each year, and that problem is actually the result of a lack of load in the critical spring periods. That problem, too, can be mitigated by adding more round-the-clock loads which can absorb more energy in the slack load periods.

And also fortunately, we find ourselves at a point in history when the cost concern can be dealt with by simultaneously dealing with a 2nd, equally perplexing, problem – namely, the climate change problem, and the need for everyone and every business to reduce greenhouse gas emissions (GHGs). In that regard B.C. has developed some plans to attack climate change, and reduce GHGs, but unfortunately, effective actions have been few and far between.

The need to reduce GHG emissions.

In its evidence, CEBC cited B.C.'s legislated Reduction Targets for GHG emissions, and also reproduced the following table showing B.C.'s progress at reducing these emissions.[12]

[12] Exhibit C4-6, pages 2-4

Greenhouse Gas Categories	2007	2008	2009	2010	2011	2012	2013	2014
TOTAL	**66,335**	**66,821**	**63,085**	**62,699**	**62,750**	**63,748**	**64,705**	**64,464**
ENERGY	**50,233**	**50,862**	**47,510**	**47,405**	**47,813**	**48,798**	**49,864**	**50,184**
Stationary Combustion Sources	**20,187**	**19,963**	**19,276**	**18,710**	**20,039**	**19,748**	**19,792**	**19,977**
Public Electricity and Heat Production	1,145	1,486	1,336	1,233	780	685	837	791
Petroleum Refining Industries	638	486	582	634	528	567	500	592
Mining and Upstream Oil and Gas Production	5,930	6,056	5,867	6,054	6,727	6,625	6,896	7,170
Manufacturing Industries	4,662	4,067	4,041	4,063	4,182	4,278	4,272	4,136
Construction	125	105	63	82	101	98	67	65
Commercial and Institutional	2,921	3,105	2,756	2,511	2,832	2,818	2,593	2,632
Residential	4,694	4,598	4,584	3,826	4,611	4,292	4,244	4,204
Agriculture and Forestry	72	60	47	307	278	385	383	387
Transport[1]	**24,997**	**25,431**	**23,307**	**23,833**	**22,361**	**23,815**	**24,668**	**24,754**
Domestic Aviation	1,490	1,405	1,250	1,195	1,119	1,295	1,330	1,329
Road Transportation	15,424	15,769	15,922	15,815	15,533	14,916	16,117	15,828
Light-Duty Gasoline Vehicles	4,630	4,655	4,688	4,387	3,936	3,851	4,069	3,950
Light-Duty Gasoline Trucks	4,328	4,474	4,663	4,589	4,330	4,381	4,771	4,891
Heavy-Duty Gasoline Vehicles	1,315	1,396	1,403	1,343	1,232	1,221	1,290	1,253
Motorcycles	14	15	16	16	15	15	16	16
Light-Duty Diesel Vehicles	81	74	82	93	97	109	122	124
Light-Duty Diesel Trucks	47	50	55	60	58	62	77	84
Heavy-Duty Diesel Vehicles	4,782	4,852	4,807	5,109	5,650	5,072	5,591	5,354
Propane and Natural Gas Vehicles	227	254	208	218	214	205	181	156
Railways	423	657	443	514	675	689	536	679
Domestic Navigation	2,548	2,498	2,607	2,641	2,197	2,608	2,126	1,848
Other Transportation	5,110	5,100	3,086	3,667	2,836	4,307	4,559	5,069
Off-Road Gasoline	759	356	259	363	426	727	394	611
Off-Road Diesel	3,410	3,842	1,951	2,461	1,597	2,774	3,146	3,421
Pipeline Transport	941	903	876	843	813	806	1,019	1,037
Fugitive Sources	**5,049**	**5,469**	**4,927**	**4,862**	**5,413**	**5,235**	**5,404**	**5,453**
Coal Mining	883	850	755	924	928	1,019	1,095	1,030
Oil and Natural Gas	4,166	4,619	4,172	3,938	4,485	4,216	4,309	4,423
CO_2 Transport and Storage	-	-	-	-	-	-	-	-
INDUSTRIAL PROCESSES AND PRODUCT USE	**4,183**	**4,186**	**3,992**	**3,779**	**3,563**	**3,746**	**3,639**	**3,454**
AGRICULTURE	**2,575**	**2,485**	**2,318**	**2,268**	**2,257**	**2,242**	**2,334**	**2,289**
WASTE	**6,143**	**6,154**	**6,205**	**6,106**	**6,070**	**5,806**	**5,625**	**5,567**
OTHER LAND USE (Not included in total B.C. emissions)								
Forest Management	**1,860**	**-1,915**	**31,602**	**65,376**	**3,049**	**15,094**	**-430**	**62,255**
Cropland Management	**117**	**117**	**123**	**130**	**144**	**157**	**170**	**192**
Wetland Management	**53**	**51**	**48**	**46**	**44**	**42**	**40**	**38**
Grassland Management	**0**	**66**		**6**	**11**	**3**	**17**	**17**
Settlement Management	**-529**	**-527**	**-525**	**-523**	**-521**	**-519**	**-519**	**-519**

Clearly, progress is severely lagging. By 2020, the law has set a target reduction in emissions of 33% below 2007 levels. That means reduction from 66 million tonnes per year (mtpa) to below 45 mtpa. There have been some small gains by 2012 (mostly as a result of the economic downturn and the impact of the carbon tax), but most of this gain was lost by 2014.

B.C. is not on any track to achieve the 2020 objective– yet the legislated targets still stand.

By 2014, half way to 2020, B.C. had reduced its emissions by a grand total of 1.9 mtpa (less than 3%) towards our 33% reduction target. In reality the provincial reduction was about 3.5 mtpa, but the oil and gas industry was expanding, and had increased by 1.5 mtpa. Most of the increase in the oil and gas industry is due to the increased development of liquids-rich gas in the Montney region of northeast B.C. – and that steady increase appears to be continuing, which will be dealt with in detail in the subsequent section.

Not only does BC Hydro need to add some load to reduce pressure on its rate increases, but also the province needs a lot of help meeting its climate action objectives for GHG reductions. This may be an ideal combination of needs, precisely because electrification with clean renewable energy is an ideal way to replace the heavy-emitting fossil fuel energy now being used for the development of the gas fields.

Fortunately, another crucial element has recently fallen in place. The federal government has asserted, with BC's concurrence, that there will be a $50 Carbon tax (or the equivalent), Canada-wide by 2022. And the tax will continue upward from there.

It should be noted that gas producers and gas shippers who are burning fossil fuels for their energy, are generally doing so in engines that can't produce energy at better than a 30% efficiency. This means that for every MWh of usable energy produced, about 600 kg of CO2 will be emitted.[13] At $50/tonne, 600 kg would cost those producers $30 in Carbon tax. Electrification could eliminate this Carbon tax. At $100/tonne, every MWh of electrification could save $60 of Carbon tax.

In conclusion, by aggressively seeking out electrification opportunities, BC Hydro has the chance to achieve two objectives. It can come to the aid of its ratepayers and mitigate the inexorable rise in its costs caused by its heavy capital spending program. And it can also come to the aid of the Climate Leadership Plan - by helping carbon intensive industries to electrify, and thereby eliminate much of their GHG emissions, and hence reduce their carbon taxes.

5. THE STRONGEST AND MOST IMMEDIATE OPPORTUNITIES

BC Hydro's Financial Plight and New Load

With its rapidly rising fixed cost structure and flat to declining[14] demand, BC Hydro should be aggressively pursuing new load especially if it is high capacity industrial load that is located close to some of its major hydroelectric generating assets. Unfortunately this is not the case.

Dramatically Increasing Gas Production and Investment in the Montney

Raw gas production in the liquids rich Montney shale fields in British Columbia. ("Montney") has been growing very rapidly since 2009[15]. Although the Montney shale fields extend into Alberta most of the investment associated with this increasing production is occurring in British Columbia.

The Montney is attracting billions of dollars of investment because of its liquids/condensate rich shale formations. The liquids sell for a price that is closely linked to the world price of oil unlike the North American price for natural gas which has become decoupled on an energy equivalent basis from the world oil price. The primary market for the liquids production from the Montney is the Alberta oilsands. It is used as a diluent so the bitumen can be transported. This market is not unlimited but currently demand exceeds Canadian supply by about 180 Mbbls/day[16]. According to Encana[17]: *"…this is a condensate play now for us with associated gas."*

The associated natural gas from liquids production is cannibalizing Canadian dry gas production.

While the CEBC does not expect investment in the Montney to proceed in a linear fashion and

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[13] 30% efficiency requires 12 GJ of gas to be burned and each GJ releases about 50 kg of CO2

[14] Exhibit B-10, BCH response to CEBC IR No. 1.11.1 and Exhibit B-22, BCH response to CEBC IR No. 3.45.1, page 4 of 4.

[15] Exhibit C4-6, pages 5 and 6.

[16] Exhibit B-22, BCH response to Zone 11 Ratepayers Group, page 3 of 4, https://www.encana.com/pdf/investors/presentations-events/montney-investor-day-presentation.pdf. Slide 15,

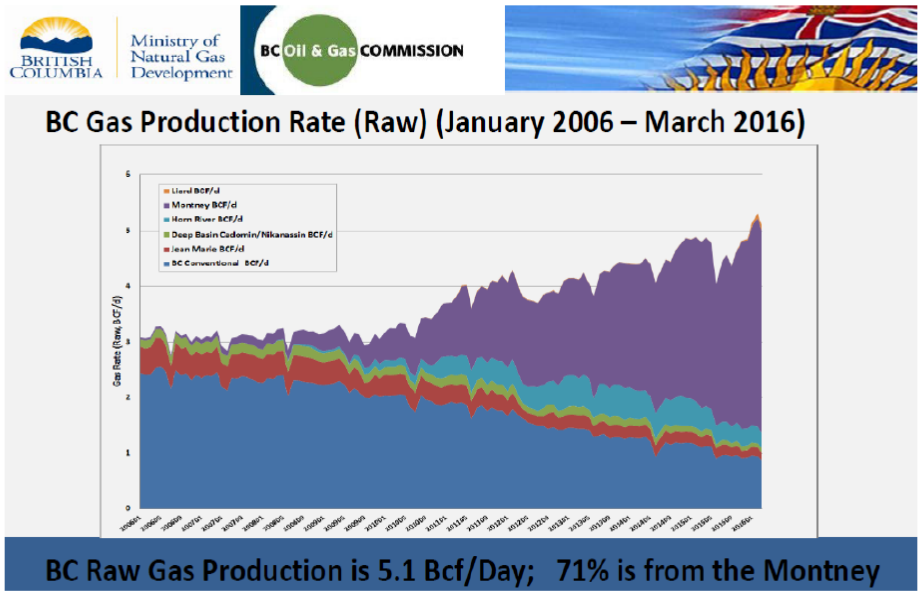
[17] Exhibit C4-6, pages 7 and 8

although the volume of liquids and market gas produced is limited by market conditions, it does expect the corresponding raw gas production to reach 7 Bcf/day by about 2020. This is the target BC Hydro should be planning for and not 2028 as currently forecast[18].

The CEBC appreciates that Montney production is well on its way to reaching the 7 Bcf/day target and although some electrification has been achieved, opportunities have already been lost and will continue to be lost unless BC Hydro becomes far more sales oriented. It is not entirely clear whether production will exceed this target amount after 2020. Given the speed at which the first 7 Bcf/day is going to be produced, it would be highly advisable for BC Hydro to try to capture the remaining opportunity and plan on capturing any additional opportunities resulting from gas production above 7 Bcf/day after 2020.

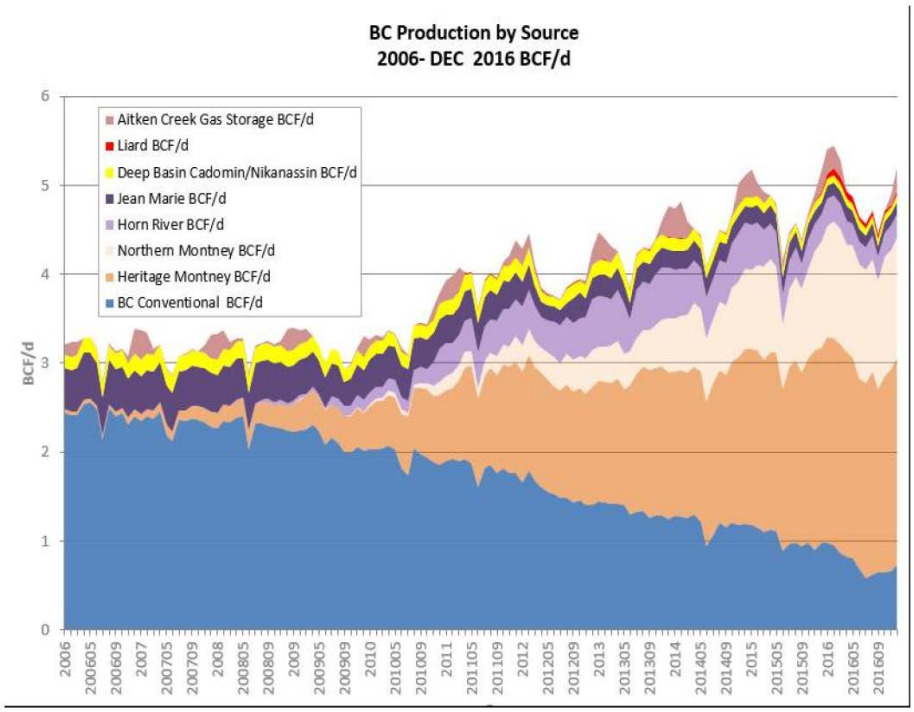
The B.C. Government has based a reduction in greenhouse gases of 4 megatonnes on a Montney production of 7 Bcf/day.[19] It is not clear whether this increase in production is total Montney production or whether it represents a 7 Bcf/day increase from 2016 levels. Irrespective, BC Hydro should try to capture all the opportunities for electrification by 2020 and beyond.

The following charts show the magnitude of the increases.



[18] Exhibit B-10, BCH response to CEBC IR 1.21.1

[19] Exhibit B-15, BCH response to CEBC IR 2.34.3



In its rebuttal evidence BC Hydro states[20] in part:

"The various third part experts used by BC Hydro undertake a more detailed assessment of natural gas market dynamics in determining future projections for B.C. natural gas production. They consider for instance:

The relative competitiveness of B.C.'s natural gas sector, including the fact that the Montney shale basin is among the lowest cost shale gas production regions in North America;

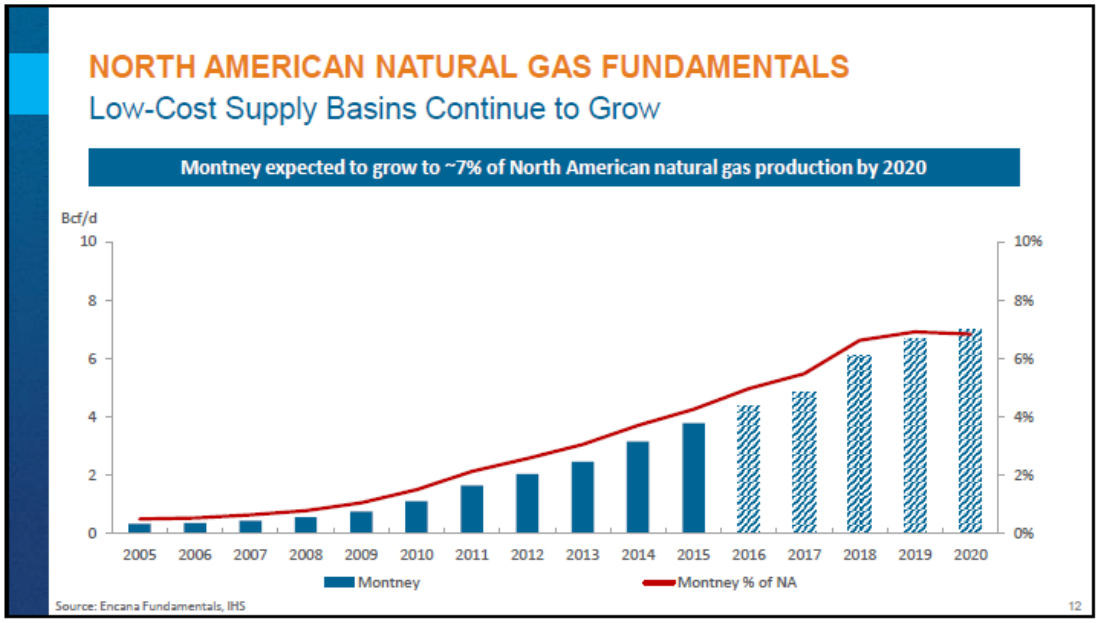
The natural gas liquids market, which is a significant component of the North American gas market dynamics. Many parts of the Montney shale 18 basin are "liquids-rich"; and

The broader interplay between global LNG markets and the North American natural gas market. For example, a large natural gas producer in the Montney region recently signed a gas supply contract with a U.S. – based LNG gas exporter."

This evidence was confirmed by BC Hydro's response to Zone 11 Ratepayers Group, IR 3.49.1[21] including the link to https://www.encana.com/pdf/investors/presentations-events/montney-investor-day-presentation.pdf. This presentation contains some very useful information about the prospects for the development of the Montney and should be carefully reviewed. For example the following graph:

[20] Exhibit B-20, Q6, A6, pages 22-23

[21] Exhibit B-22, page 3 of 4



In its evidence, the CEBC provided the following extracts from a Year End Results Conference Call by Encana[22]:

"Our 2017 Montney program is set to deliver significant margin expansion. Last year, our Montney production averaged 20 barrels of liquids per million cubic feet. The average ratio of our 2017 drilling program is 85 barrels per million cubic feet or a 325% increase in liquids content. As a result, we expect to more than double our liquids production in the Montney by the end of the year. The vast majority of this liquids growth is premium value condensate.

The Tower and Sunrise plants remain on-track to come on-stream during the fourth quarter of 2017. They are on schedule and under budget. We intend to ramp our 2017 production volumes into these plants upon commissioning…

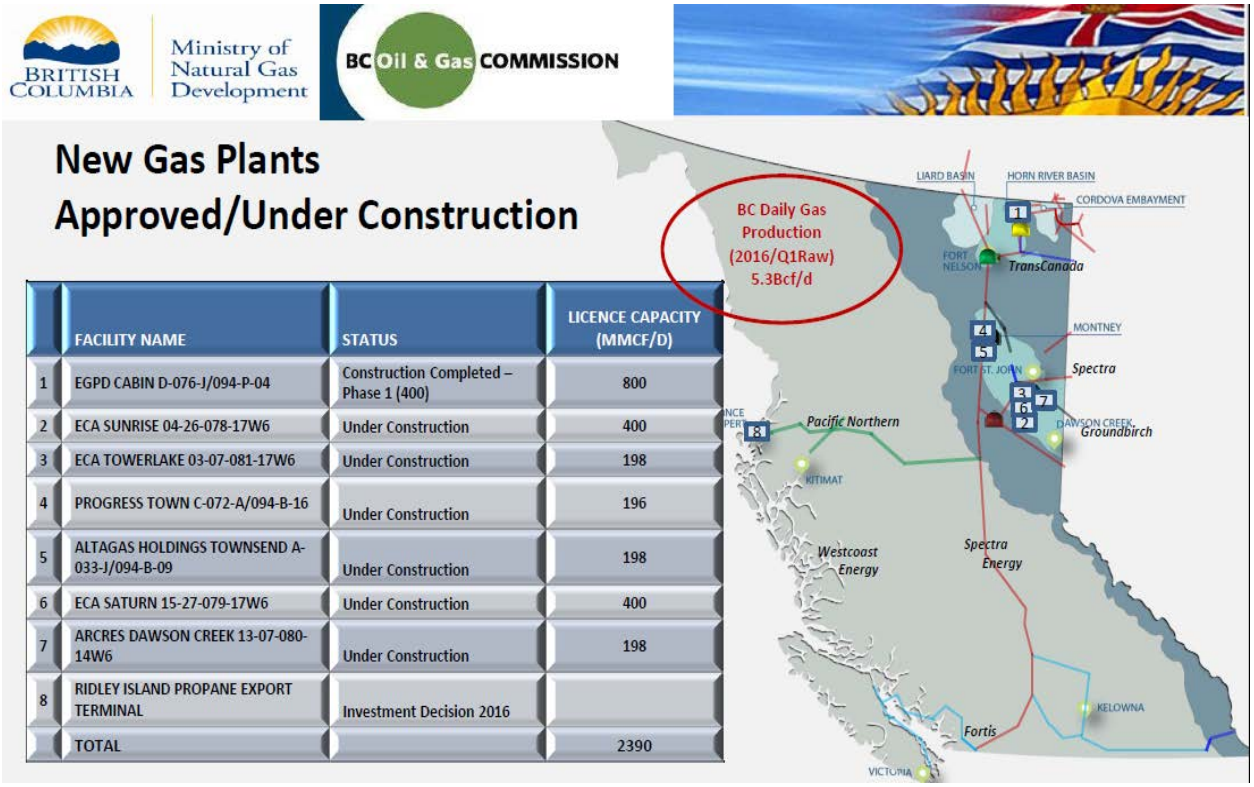
Our Canadian condensate production is connected via pipeline to the premium Edmonton market center. It is our view that Western Canada will continue to require condensate imports for the foreseeable future. So condensate in Canada will continue to command a premium to Gulf Coast pricing…

Just an interesting side note: If you look, and I think Sherri mentioned this in her comments. If you look at our Montney production at the condensate-gas ratios, we're now producing at a $55 oil prices with a small discount for condensate in Canada, which is actually, recently it's been trading pretty flat with TI. We actually generate a very strong return at a minimal gas price, which was why she made the comment about this a condensate play now for us with associated gas."

The following table is also instructive[23]:

[22] Exhibit C4-6, pages 7 and 8

[23] Exhibit C4-6, page 7



	FACILITY NAME	STATUS	LICENCE CAPACITY (MMCF/D)
1	EGPD CABIN D-076-J/094-P-04	Construction Completed – Phase 1 (400)	800
2	ECA SUNRISE 04-26-078-17W6	Under Construction	400
3	ECA TOWERLAKE 03-07-081-17W6	Under Construction	198
4	PROGRESS TOWN C-072-A/094-B-16	Under Construction	196
5	ALTAGAS HOLDINGS TOWNSEND A-033-J/094-B-09	Under Construction	198
6	ECA SATURN 15-27-079-17W6	Under Construction	400
7	ARCRES DAWSON CREEK 13-07-080-14W6	Under Construction	198
8	RIDLEY ISLAND PROPANE EXPORT TERMINAL	Investment Decision 2016	
	TOTAL		2390

Of the new gas plants in the table, numbers 2 through 7 are all in the Montney region. The above represents a small sampling of the billions of dollars in investment that is taking place in this region and it is all irrespective of LNG development in B.C.

The Application record can't even keep up with the development and investment decisions that are being made in relation to the Montney and is incomplete. For example in March 2017[24], TransCanada announced that filed a variance application to proceed with construction of the North Montney Mainline Project. The requested variance would allow TransCanada to move forward with the construction of the majority of this project at an estimated capital cost of approximately $1.4 billion, prior to a final investment decision on the Pacific Northwest liquefied natural gas project. In support of the variance, TransCanada has secured new 20-year commercial contracts with 11 shippers for approximately 1.5 Bcf/d of firm service.

Construction is planned to begin in the first half of 2018, with completion phased in over a two-year period beginning in April 2019.

Enbridge is spending $500 million expanding its gas gathering system in the Montney and Duvernay[25]. The expansion is called the Spruce Ridge project and is expected to boost pipeline capacity by 400 million cubic feet per day by 2018. It is also planning to spend about $1 billion

[24] https://www.transcanada.com/en/announcements/2017-03-20transcanada-seeks-approval-to-proceed-with-north-montney-mainline-project/

[25] http://business.financialpost.com/news/enbridge-inc-expands-oil-and-gas-pipeline-capacity-as-production-surges

expanding its line between northern B.C. and Vancouver.

BC Hydro's response to this tremendous opportunity to sell electricity and reduce greenhouse gas emissions is to say the least, very puzzling[26]:

"CECBC's evidence is based on documented government sources and corporate information. CECBC's comments regarding future British Columbia gas production are generally consistent with BC Hydro's assessment.

BC Hydro agrees that electrification of the Montney gas production represents a significant, albeit uncertain, opportunity for BC Hydro. The uncertainty is related to: (1) changing demand and supply conditions of future North American gas and liquids markets, as well as global LNG markets; and (2) the extent to which gas producers decide to electrify portions of their operations."

BC Hydro's assertion that the Montney represents *"a significant, albeit uncertain opportunity"* is not correct. With billions of dollars of investment decisions currently being made there is certainty, not uncertainty. And BC Hydro should be vigorously trying to influence these decisions by promoting the use of renewable electricity to the makers of these decisions. If the decision is made to use fossil fuel, the probability of subsequently convincing the owners to electrify their facilities is slim and none. Sales pitches have to be made now and not in the context of the development of BC Hydro's 2018 Integrated Resource Plan or some other BC Hydro or Government initiative.

By any measure, the pace of raw gas production in the Montney is greatly exceeding BC Hydro's forecast. According to the above table entitled: "*North American Gas Fundamentals*", Encana expects Montney gas production to reach 7 Bcf/day by 2020. Even adjusting for any production from the Alberta portion in Encana's estimate, BC Hydro's lagging Montney forecast has production reaching this level in 2028[27]. CEBC recommends that the BCUC direct BC Hydro to immediately revise its Montney raw gas production forecast to reflect the reality of increasing production and investment.

Potential Size of the Opportunity to Sell Electricity in the Montney

It takes large amounts of energy to process raw, liquids rich gas into a product that can be safely transported in the mainline natural gas pipelines. At a minimum, this gas needs to be passed through a shallow cut processing plant where it is chilled to about -37 degrees centigrade. By comparison the amount of energy required to process dry gas is the equivalent of chilling it to about 0 degrees centigrade. Deep cut processing requires chilling to about -81 degrees centigrade.

When asked about the maximum electrical intensity for a shallow cut gas processing plant BC Hydro responded[28]:

"*BC Hydro understands that a shallow gas processing plant is a facility that extracts various natural gas liquids (e.g. propane, butane, pentanes). BC Hydro's response to CEA IR 1.21.4 includes a range of electrical intensities from 0.07 to 0.245 MW/MMcf day, which is consistent*

[26] Exhibit B-20, page 30

[27] Exhibit B-10, BCH response to CEBC IR 1.21.1

[28] Exhibit B-15, BCH response to CEBC IR 2.43.2

with information provided by customers requesting service.

While BC Hydro is not aware of what the maximum electrical intensity factor for a shallow gas processing plant is, BC Hydro understands the high end of the electrical intensity range provided in our response to CEA IR 1.21.4 is more representative of gas processing plants that extract natural gas liquids than the average electrical intensity BC Hydro used to estimate the work energy requirements associated with its long term gas production estimates."

It is unusual that BC Hydro does not know what the maximum electrical intensity factor for a shallow gas processing plant is because these plants are being hooked up to its system (e.g. the Saturn and Sunrise plants[29]). But it is clear that it is not using the 0.245 MW/MMcf day factor when estimating the work energy requirements associated with its long term gas production estimates. It is using the average intensity. Given that the investment in the Montney is going into liquid rich production, this is an error.

Applying the 0.245 MW/MMcf day factor to a 400 MMcf/day gas processing plant, the average expected load would be about 100 megawatts.

By contrast the electrical load for a 400 MMcf/day dry gas processing plant is about 10 megawatts[30]. The 100 megawatt figure is probably more representative of a deep cut processing plant, which there are likely to be more of in B.C. as producers extract the maximum amount of liquids.

In response to CEBC IR 1.9.4[31] BC Hydro provided the following extract from the B.C. Climate Leadership Plan:

"Electrification of natural gas developments in the Montney formation in Northeast B.C. is currently proceeding with existing infrastructure to avoid GHG emissions by up to an estimated 1.6 million tonnes per year. Full electrification of the Montney Basin would avoid up to 4 million tonnes of emissions per year, minimizing the GHG footprint of upstream natural gas development to ensure that B.C. has the cleanest LNG in the world."

In response to CEBC IR 2.34.3[32] BC Hydro states:

"Government has advised BC Hydro that these estimates were developed internally, based on incremental natural gas production of 7 bcf/d, information provided by industry on the energy requirements and emission profile for a typical gas processing facility, and assuming that 100 per cent of the energy required for compression would be provided by electricity rather than natural gas."

And in response to CEBC 2.34.7[33]:

"Avoiding 4 million tonnes per year of emissions through full electrification of the Montney formation is expected to require approximately 6,700 GWh/year of electricity supply, depending on the efficiency of the gas use avoided. The timing and scale of additional load growth is highly

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[29] Exhibit C4-6, page 7

[30] Exhibit B-15, BCH response to AMPC IR 2.9.4, Attachment 1

[31] Exhibit B-10

[32] Exhibit B-15

[33] Exhibit B-15

uncertain, but BC Hydro is of the view that should this load materialize, it can be supplied with existing and planned resources as well as new clean energy resources. Supplying this load would also require additional transmission capacity."

When compared to the result of a calculation using an energy intensity factor of .245 MW/MMcf day as applied to 7 Bcf/day of production i.e approximately 14,000 GWh, the estimate of 6,700 GWh/year seems very low even when adjusted for the probable deep cut bias. What appears to be happening is that the electricity requirements for processing liquids rich natural gas aren't being properly recognized. But the two figures do provide an idea of the potential size of the sales opportunity that awaits BC Hydro.

Given that there was no oral hearing, it is difficult to assess whether the load figures provided by BC Hydro and the Government include anything other than potential gas processing plant load. However in this respect, the below CEBC IRs and BC Hydro responses are instructive especially as to BC Hydro's apparent approach to selling more electricity.

IR 2.43.1[34]:

"*Please provide the maximum electrical intensity factor for moving the gas from the wellhead to a gas processing plant if this activity is electrified to the fullest technical extent"*.

Response:

"*BC Hydro does not have the requested information since there have not been any material service requests to supply electricity to move gas from the wellhead to a shale gas processing plant.*

Future opportunities for electrifying these activities within the oil and gas sector may emerge as low-carbon electrification incentive programs pursuant to Climate Leadership Plan are implemented."

IR 2.43.5:

"*Please provide the maximum electrical intensity factor for a gas drilling rig of the type used in the Montney if this activity is electrified to the fullest technical extent."*

Response:

"*BC Hydro does not have the requested information since there have not been service requests for supplying electricity to gas drilling rigs."*

Future opportunities for electrifying these activities within the oil and gas sector may emerge as low-carbon electrification incentive programs pursuant to Climate Leadership Plan are implemented."

IR 2.43.6:

"*Please provide the maximum electrical intensity factor for fracturing equipment of the type used in the Montney if this activity is electrified to the fullest technical extent."*

Response:

"*BC Hydro does not have the requested information since there have not been service requests for supplying electricity to hydraulic fracturing activities.*

[34] Exhibit B-15

Future opportunities for electrifying these activities within the oil and gas sector may emerge as low-carbon electrification incentive programs pursuant to Climate Leadership Plan are implemented."

IR 2.43.7:

"*Please provide the maximum electrical intensity factor to pump market gas on a MW/MMcf/day/100 kilometer basis in a pipeline if this activity is electrified to the fullest technical extent."*

Response:

"*BC Hydro does not have the requested information since there have not been material service requests for supplying gas pipelines.*

Future opportunities for electrifying these activities within the oil and gas sector may emerge as low-carbon electrification incentive programs pursuant to the Climate Leadership Plan are implemented."

It would behoove BC Hydro to become much more sales oriented and not wait for potential customers to make inquiries and interconnection requests. It wouldn't be waiting for potential customers to supply it. BC Hydro needs to immediately assess all aspects of the Montney market that can be electrified as based on an increase in production of 7 Bcf/day (from 2016 levels) including:

- electric drill rigs;
- fracking;
- compression from the wellhead to the gas processing plant;
- gas processing plants assuming a minimum of shallow cut processing; and
- compression for mainline gas pipelines.

Without this information BC Hydro can't properly and proactively market its electricity to the Montney producers.

Transmission Expansion

If BC Hydro's core transmission system in the Montney area is not expanded or other transmission and renewable generation solutions found, any thought of using renewable electricity on a large scale basis to provide some of the energy required to produce gas in the Montney is moot. As the Application review process is not about transmission alternatives, the CEBC's analysis will confine itself to what BC Hydro must do during the test period to expedite the development of electrical transmission in the Montney.

The CEBC is also concerned about BC Hydro's response time to interconnection requests which was covered in some detail in the "*Industrial Electricity Policy Review Task Force Final Report (2013)*[35]. It should be one of BC Hydro's objectives during the remainder of the test period to

[35] Section 6.13, *"Delays in transmission availability are cited as an obstacle to industrial development in British Columbia. BC Hydro's transmission interconnection process is perceived as slow, cumbersome, unresponsive and expensive by customers. The risk of missing in-service dates could drive new industries to self-supply rather than take grid service."*

expedite interconnection requests.

In a response to a CEBC Information Request about transmission expansion[36], BC Hydro provided the following extract from the B.C. Climate Leadership Plan:

"Capital Funding will be necessary to develop upstream electrification of several key projects: Peace Region Electricity Supply Project, North Montney Power Supply Project, and Other upstream electrification infrastructure."

In follow-up Information Requests[37] BC Hydro said:

"The Peace Region Electricity Supply Project is included in BC Hydro's 10 Year Capital Forecast with a planning cost allowance of $162.9 million. The Project is also listed in Appendix 1 and described in Appendix J of the Application. The Project is currently in the Identification Phase and not sufficiently advanced to have a scheduled in-service date. Please refer to BC Hydro's responses to BCUC IRs 1.102.4 and 1.102.5, AMPC IRs 1.17.1, 1.17.2 and 1.17.3 for further information on the timing of the project.

The North Montney Power Supply Project is not included in BC Hydro's 10 Year Capital Forecast or in the Application as the project is proposed by an oil and gas company. BC Hydro has had some discussions with this company about how best to develop the project to integrate it into the BC Hydro system should this company decide to proceed with the Project."

And[38]:

"As stated in BC Hydro's response to BCUC IR 1.102.5, BC Hydro currently has available area transmission capacity to serve new oil and gas producer loads in the Peace Region. However, as more producers choose to electrify their operations it will be necessary to expand the transmission infrastructure in the Dawson Creek and Groundbirch areas.

The timing of when additional area transmission capacity is required depends on the timing of new loads, their location and their size. If necessary BC Hydro intends to use temporary generation, located at or near customer sites, as a bridging measure if there are area or localized transmission constraints prior to new transmission capacity being built."

And[39] in relation to the Peace Region Electricity Supply Project:

"In general, for a transmission project of this size, it is anticipated that the long lead time is three to five years from the time all material permits, licences and approvals are applied for to the date that the transmission component is in-service. With this period the construction, would take approximately two to four years.

The Peace Regional Electricity Supply Project is still in the identification Phase and is not sufficiently advanced to have a preferred alternative. As a result, there is insufficient information on the scope to establish a full project schedule at this time…"

With respect to the Peace Region Electricity Supply Project, consultation with First Nations has

[36]Exhibit B-10, BCH response to CEBC IR 1.9.4

[37]Exhibit B-15,BCH response to CEBC IR 2.34.1

[38]Exhibit B-15, BCH response to CEBC IR 2.35.3

[39]Exhibit B-10, BCH response to CEBC IR 1.18.2

not been completed[40]:

"…Accordingly we have shared project information and sought and received input over the past three years, including on project alternatives and options…

We continue to provide First Nations with information and to seek their input as part of our ongoing consultation with them."

What is apparent is that in the face of the rapid expansion of gas production in the Montney, BC Hydro's transmission response is not consistent with a sales oriented company. The delivery of electricity has to occur in lock step with development of the Montney – not after – but perhaps subject to BC Hydro being able to bridge the long term supply of renewable generation with temporary on site thermal generation.

The CEBC does not understand why TransCanada is expecting to complete the North Montney pipeline with an estimated cost of $1.4 billion, in far less time that it would take BC Hydro to complete the Peace Regional Electricity Supply Project with an estimated cost of only $163 million.

The CEBC requests the BCUC direct BC Hydro to complete as much works as possible on this transmission project during the test period so that it is shelf ready to construct when it is needed.

B.C. Climate Leadership Plan

In response to a CEBC Information Request about the B.C. Climate Leadership Plan, BC Hydro provided the following information[41]:

"Government announced in the Province's Climate Leadership Plan that it would work with BC Hydro to expand the mandate of BC Hydro's demand-side management programs to include investments that reduce greenhouse gas emissions. It also identified the electrification of natural gas developments as a significant opportunity to achieve these reductions. BC Hydro has been working with its customers to explore a program that would enable natural gas processing facilities to electrify while also providing a net benefit to taxpayers over a defined period.

For Gas processing facilities in the Peace Region, BC Hydro has been in active discussion with its customers and members of the Canadian Association of Petroleum Producers regarding a potential framework that would consist of a fixed incentive per MW. In return for the incentive, BC Hydro would also retain ownership of a share of the offsets that would arise from such projects…"

While BC Hydro's response to the Climate Leadership Plan is a step in the right direction in terms of increasing BC Hydro's electricity sales and reducing greenhouse gas emissions, the key question is:"*How quickly is this going to happen?"* The timing of the offer of incentives and the availability of transmission are probably more critical than the amount of the incentives. The incentives have to be available when the investment decision is made, and transmission as required. BC Hydro has indicated that on site generation can be used to bridge the gap between the date transmission is required and the date it is available but has provided no details.

The move towards a B.C. carbon tax of $50 per tonne by 2022 should also be considered by BC

[40]Exhibit B-10, BCH response to CEBC IR 1.18.1

[41] Exhibit B-15, BCH response to CEBC IR 2.35.1

Hydro when any offer of fixed incentives is made.

Montney Summary

With its ballooning fixed cost structure and flat to declining demand, BC Hydro needs to sell more electricity to existing and new customers and this electricity must be efficiently used by these customers. The Province of B.C. needs to reduce greenhouse gas emissions. An opportunity to do both exists in the Montney but all the evidence shows that BC Hydro is not aggressively pursuing it.

BC Hydro's forecast of Montney raw gas production is seriously lagging the development that is occurring. It needs to be immediately revised.

The potential increase in demand for the electricity associated with the increased production has not been properly identified. Matters such as the electricity intensity of electric drilling rigs, fracking equipment, the transport of raw, gas to processing plants, shallow and deep cut processing plants and the transport of market gas have not been properly researched. This work needs to be carried out immediately.

While credit needs to be given for programs that may be developed under the Climate Leadership and in conjunction with the Federal Government, BC Hydro should not be waiting for the fine details of these programs to be put in place before it defines the Montney electrification market and develops its sales plan to achieve maximum electricity sales. These activities have to be undertaken immediately.

6. BC HYDRO'S CAPITAL INVESTMENT PROGRAM

The first time capital expenditures begin to directly affect the revenue requirement is when the assets are put into service and the expenditures become capital additions. However, spending a lot of time and effort to carefully scrutinize the capital additions in the test period would not seem to be a useful exercise.

By the time BC Hydro's capital spending reaches the stage of being a capital addition, it's far too late to do anything about it. The money has long since been spent. The amortization rates are pretty well fixed according to the type of assets being added. And even the debt has already been acquired and the interest rates set (and probably at the cheapest rates available). So very little remains to be acted upon. It is a fait accompli.

If the BCUC is to have any positive influence within this test period, it has to influence the choices of current project spending in the best way to benefit future rates – quite possibly rates that won't come into force until long after the test period has passed.

CEBC sees only two projects mentioned in BC Hydro's Capital Plan that can address the need to serve the low-carbon electrification goals for the northeast gas producers and processors. These are, namely:

- The Fort St. John and Taylor Electric Supply ($53 million, in the Implementation Phase)
- Peace Region Electric Supply ("PRES", in the Identification Phase)

They are both transmission projects. They are both urgently needed, and they are not a big portion of the approximately $20 billion Capital Plan. They should both be given the highest

priority. However, rather than being placed high on BC Hydro's priority list, only the smaller one is in the implementation stage.

The other (PRES) is still relegated to the nascent stage of "Identification", without even a firm capital estimate or a timeline to completion. This is even though the PRES has been known to be needed since at least 2015[42], and even though the current situation is approaching critical:

"Implementation of these Climate Leadership Plan initiatives could increase forecast load in the region and accelerate the forecast timing of that load. Under the high load scenario, the ability of the system to supply the growing load under normal conditions could be exceeded as early as fiscal 2018… As the loads in the region are exceeding the capacity added under the Dawson Creek /Chetwynd Area Transmission Project, new customers are required to take service at an N-0 service level… Specifically, new customers are required to participate in a protection and control scheme… that will shed their loads during system contingency events."[43]

CEBC is further concerned that, given how far BC Hydro's gas production and corresponding electricity forecast is lagging actual production, that PRES is likely to be inadequate to serve the demand even on the day it goes into operation.

BC Hydro was careful to point out in its final argument that the BCUC has been specifically barred by the Government from taking any action or decision to hamper the execution of such projects.[44] However, that does not mean the BCUC cannot direct BC Hydro to specifically reprioritize and accelerate these projects.

As for generation projects, the only real growth project in the Capital Plan is Site C, and it is an enormous long-lead-time project that is, unfortunately, set to produce its energy with no particular short term need in mind to be served. However, the other generation projects that could be producing energy that is actually needed (but at a much earlier time), are nowhere to be found in the Capital Plan. There are no generation projects in the Capital Plan, IPPs or otherwise that could serve the very current need for the electrification of northeast gas production and processing. These projects are needed long before the Site C energy will be available. They should be in the Capital Plan.

7. MISCELLANEOUS

Bridge and Campbell River systems

BC Hydro's responses to CEBC Information Requests show that adequate system rehabilitation plans for the Bridge and Campbell River systems have not been developed. In fact there isn't any type of plan for the Campbell River System. Given the potential cost of rehabilitation and the impacts of climate change it makes no sense whatsoever to proceed with piecemeal rehabilitation. Despite the work that is already underway at John Hart, and the cost of seismic upgrading is already going to exceed the previous estimate, the CEBC requests the BCUC to

[42] BCH Final Argument, Appendix A, page 34, paragraph 90

[43] Ibid. Page 31-32, paragraphs 86 and 87

[44] BCH Final Argument, Appendix A, page 31

direct BC Hydro to commence and complete a "clean sheet" analysis of the Bridge and Campbell River systems during the test period. The generation facilities that are there today may not be the facilities that should be there tomorrow.

Powerex – Renewable Energy Credits

Powerex is earning revenue from what can generally be described as "renewable energy credits" obtained as part of electricity purchase agreements that BC Hydro entered into with true independent power producers[45] ("IPPs"). The revenue earned is recorded in Powerex's financial statements which are not made public. These statements are subsequently consolidated with BC Hydro's. The revenues from the sale of renewable energy credits or attributes attributed to IPP generation should be more properly credited to BC Hydro's cost of energy.

From time to time concerns, often unfounded, are raised about the high cost of electricity purchased from IPPs. The actual cost of these contracts cannot be calculated without access to the amount of revenue that accrues to BC Hydro through the sale of renewable credits.

CEBC requests the BCUC to direct BC Hydro to record the revenue from the sale of IPP renewable credits to BC Hydro's cost of energy or in a similar manner that results in transparent disclosure. As California pursues greenhouse gas reduction within its borders, CEBC expects the value of IPP renewable credits to increase.

[45] BCH has a very expansive definition of independent power producers that includes any third party that supplies it with electricity. The CEBC's comments about green credits are with respect to independent power producers whose primary business is the production of electricity and not forest product companies, Rio Tinto Alcan, Columbia Power and Columbia basin trust and similar entities BCH purchases electricity from.