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British Columbia Utilities Commission, Sixth Floor
900 Howe Street, Box 250
Vancouver, B.C.
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Attention: Patrick Wruck, Commission Secretary

Dear Sir:

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

Final Argument

Executive Summary

Distributed Generation (DG) Customer-Generators (CG) who have Net Excess Generation (NEG) for sale, including Net Metering (NM) ones with a nameplate capacity of 50 kW or less and 750 volts or less, have no program or tariff that can be administered by the Commission through which they can sell their production to FortisBC (FBC). In the words of Madam Justice Hudart , as a consequence they "...*are vulnerable to arbitrary management decisions*" (Princeton Light and Power Ltd vs MacDonald, 2005 BCCA 296, 67).

- The Commission should consider directing FBC to develop a tariff and program, like BC Hydro's Micro Standing Offer Program (MSOP), that would meet the needs of CGs beyond the RS 95 tariff offset program. With this change small scale DG, including NEG, could be sold to the Company in accordance with the objectives of Action #25 of the 2007 Energy Plan and section 2 of the *Clean Energy Act* (*CEA*).

DG, and NM in particular, can and should be incorporated into the LTERP and LTDSMP. Despite the reasoning made in its Final Argument at 95 to 102, FBC has provided insufficient empirical evidence to support its conclusions. In contrast, our household has provided this Commission panel with empirical evidence from our own consumption patterns and from NM#1 that clearly show the potential of DG/NM as a means to conserve energy in a firm, reliable and long term manner (Appendix A and C10-8, 2016 NM#1 FortisBC Electrical Charges and Net Metering Transfer Values).

- The RS 95 tariff/program has the same attributes as a Demand Side Management (DSM) program as defined under 1.1 of the *Clean Energy Act* (*CEA*) and the Commission should consider directing FBC to incorporate the program into the Company's suite of DSM programs (see FBC's own statement, B1, Appendix J, 3.4 Rooftop Solar Power [Distributed Generation]: "*DG can be considered both a supply-side or demand-side resource*", p 41, line 16).

- The Commission should consider not approving the DSM portion of the LTERP and LTDSMP until there are clear objectives, stated goals, and a defined pricing structure for customers to sell DG, including NM NEG.

FBC, for example, has thus far not considered the NM program as a means to enhance home heat fuel switching from natural gas and as a means to address the high winter cost concerns of electric heat customers who cannot access natural gas or any other heat source (C10-8, Ibid).

- This Commission panel should consider either attaching to this hearing a settlement panel process to address the issue of a DG/NM NEG pricing structure, or consider proposing a separate hearing beyond this one in accordance with powers granted it under 60 (2) and (3) of the *Utilities Commission Act* (*UCA*).

- The Commission should consider directing FBC to extend to DG, including NM CGs, the same avoided cost valuation credit analysis for DSM that it is prepared to afford Self-Generators (SG) under tariffs 30 and 31, in accordance with the findings of the Commission panel in Order G-27-16.

- The Commission should also consider directing FBC to take into full account the lack of line loss and lack of use of transmission lines from point of purchase to point of retail, similar to that claimed by FBC for its own proposed Solar PV Farm pilot project in Kelowna and acknowledged in its own application (Final Argument, 66-67 and B-1, Appendix J, Wheeling Costs, p 7-8).

Since December 2005 our household has invested an average of $424.15 in each billing period in DSM, energy savings and net metering – offsetting that investment with 36.858 MWh of energy savings. This has resulted in us achieving an estimated dollar ($) value credit ranging from a low of $29.19 per billing period in 2007 to an average of $99.28 so far in 2017, which still results in a pay back period of 57 years.

In the first five billing periods of 2017 under the RS 95 tariff, our household has paid FBC $191.52 for the net of .328 MWh of electricity delivered from their grid, while the Company has earned $429.86 from sale of both what we purchased from and transferred to them, at a rate per MWh of $206.36. Yet the Company erroneously claims that it and other customers are subsidizing those CGs, like us, who achieve, or are close to achieving, net zero while only being credited half what the Company is earning from us.

Further, despite claims to the contrary by FBC, our household has been transferring back to the grid, from our solar PV production, a minimum of 10% of consumption in the two winter billing periods of December and February. In fact the empirical evidence for the potential of DG/NM is acknowledged by FBC when they state in an appendix to their own application that:

"*If significant in amount, DG can also help utilities avoid transmission and distribution system upgrade costs, reduce line losses and reduce system energy requirements. The increasing popularity of distributed solar can result in more buildings and/or homes reducing their energy consumption*" (B-1, Appendix J, 3.4 Rooftop Solar Power (Distributed Generation), 41).

Our preference all along, as stated in a May 2016 letter to the Commission, has been for ourselves and our neighbours, who are enrolled in the FBC NM program, to sit down and resolve our differences with the Company through a face to face discussion (E-2, FortisBC Inc. Net Metering Program Tariff Update Application ~ Project No.3698875).

In conclusion I simply want to state to the Commission that it is not in the public interest for the current impasse between NM CGs and the Company to continue, and for FBC, a single public utility, to be allowed to continue retarding the development of energy self-generation and grid savings energy measures by local governments, small businesses and residents within its service territory.

Background to 2016 LTERP AND LTDSM Hearings

In the preamble to Order G-199-16, the Commission panel states:

"*The Clean Energy Act (CEA) was introduced on April 10, 2010 , by the Provincial Government of British Columbia, and contains a list of British Columbia's energy objectives in section 2 of the CEA. One of these objectives is to "use and foster the development in British Columbia of innovative technologies that support...the use of clean and renewable resources.*

"Prior to the introduction of the CEA, the provincial government's emphasis on the promotion of energy efficiency was articulated in both the 2002 and 2007 Energy Plans. The 2007 Energy Plan is subtitled: 'A Vision for Clean Energy Leadership' and includes as Policy Action #25: 'Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources'" (1.3 Legislative and Regulatory Context, Order G-199-16, p 3-4).

The panel, however, during discussion of "Decision Scope" states:

"*The Panel notes that FBC also has two other applications coming before the Commission which may provide broader guidance regarding FBC's self-generation strategy: the 2016 Long Term Electric Resource Plan & Long Term Demand Side Management Plan (LTERP); and the FBC Self-Generation Policy Stage II Application (SGP). The Panel feels that these broader issues (for example, whether the Program should be expanded beyond its original intent) are more appropriately addressed following the LTERP and/or SGP proceedings as these proceedings may provide broader guidance regarding FBC' s self-generation strategy*" (2. Decision Scope, Order G-199-16, p 5).

And later reiterates this view in Appendix A of the Order:

"*The Panel reiterates its comments made earlier in this decision that broader issues, such as whether the scope of the NM programs should be expanded to include customers who generate Annual NEG, , and if so what the appropriate price should be, are more appropriately addressed as part of or following the LTERP and/or SGP proceedings as they may provide broader guidance regarding FBC's self-generation strategy*" (Panel Determination: The Panel rejects the proposed change in the purchase price of NEG, Appendix A, Order G-199-16, p 19).

With Regard FBC's SGP Stage II Application, currently suspended by Order G-90-17, the Company makes the following statement:

"*The Panel is in agreement with the applicability of any GBL Guidelines to both transmission and distribution customers with the caveat that it should only be applied to customer generation facilities of over 50 kW*" and "...*750 to 35,000 volts measured phase to phase*" (B-1, Applicability of Self-Generation Customers, 2.4.1 Eligible Customers, FortisBC Inc. Self-Generation Policy Stage II Application ~ Project No.3698820, p 13, line 13 to 21**).**

This situation currently leaves CGs with production systems of 50 kW and less and 750 volts and less in a state of limbo – trapped between FBC, which has applied for the right to remove customers from its NM RS 95 tariff/program for any production of NEG, and having no program and no tariff under which to sell either production or NEG to the Company, as acknowledged when they state:

"*FBC has no tariff or program in place to purchase IPP power. However, FBC purchases from a small number of IPP's at a monthly energy rate ranging from $17 to $43 per MWh for 2015, based on individual contracts with the IPP*" (Net Metering Program Tariff Update B-12, BCUC IR 13.5).

Beyond objective 2(d), cited by the Commission panel in Order G-199-16, the following *CEA* objectives apply equally as well:

i. Greenhouse gas reduction targets as outlined in 2 (g)
ii "*(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;*
iii *(c) generate 93% of electricity in British Columbia from clean and renewable sources*
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;
(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;
(k) to encourage economic development and the creation and retention of jobs;
(l) <u>to foster the development of first nation and rural communities through the use and development of clean or renewable resources</u>";

In this context it is submitted that in Order G-27-16 at 4.3.1, with regard to FBC's requirement to follow the *CEA,* and contrary to certain reasonings and statements made by FBC in its Final Argument in this hearing, the Commission has previously found, that:

"*The Panel recognizes that both the CEA, which is an act of the BC provincial legislature setting out specific energy goals, and the BC Energy Plan, are applicable throughout British Columbia, with the exception of certain clauses that apply exclusively to BC Hydro. Any public utility within BC, including FortisBC, falls under the authority of the CEA"* (G-27-16, 4.3.1).

In regard to 2 (c), (d), (k) and (l) of the *CEA,* the **Regional District Central Kootenay Area D and Kaslo Green Opportunities Energy Scan** (as published by the Community Energy Association December 2016) was submitted as evidence of FBC's lack of a clearly defined policy towards CG DG which hampers energy savings and self-generation development within its service area (C-10-9):

"*The challenge is that both systems are located in the Fortis Electric territory. The Fortis Electric net metering system is designed only to reduce electricity consumption and not revenue generation..."* (Ibid, p4).

In addition, it has subsequently been determined that the Village of Slocan (as a potential small-hydro CG) has not been able to persuade FBC to consider purchase of electrical energy from its proposed micro-hydro project. The Village is instead now discussing the option of wheeling their energy to BC Hydro, which is currently purchasing micro-hydro produced by the Village of Nakusp from their water system.

Further, my recent tour (the second one) of the City of Kimberley's Sun Mine 1 MW solar project revealed that they are grossing a 14.3% return on an average purchase price of $110 per MWh (BC Hydro pays multiple time-of-use rates for this energy), which is going into a long term Operation and Maintenance (O&M) fund. In addition BC Hydro currently pays its NM customers $99.90 per MWh for NEG, $106.5 per MWh for MSOP electricity, and $109.5 for Standing Offer (SOP) energy. Further, BC Hydro has confirmed that they have had a Commission-ordered price for NM NEG since March 2004 (that started at 5.4 cents per kWh), SOP rules since 2010 and a MSOP price since February of 2016 (email communication from BC Hydro, November 9th, 2017).

In contrast, FBC, in addition to opposing purchase of electricity from small local governments and businesses (contrary to the legal requirements of the *CEA*), has no MSOP or SOP program and pricing. Rather, it proposes to reduce the purchase price of NEG from NM customers from retail rate to the BC Hydro RS 3808 PPA Tranche I rate of $48 MWh – despite the fact that the calculated Long Run Marginal Costs (LRMC) for renewable and clean sources in their Final Argument is quoted as being $100.45 per MWh (Final Argument, 180).

On this last point it is submitted that the Commission panel in G-27-16 found that the LRMC is an appropriate mechanism to use in assessing the cost effectiveness of a purchase price for DG:

"*BC Hydro further submits that it assesses cost-effectiveness for its DSM, including load displacement, against the LRMC of acquiring electricity generated from clean or renewable resources in BC. In other words, BC Hydro compares the purchase price of self-generation to the LRMC and if the purchase price of self-generation is lower than the LRMC of clean energy resources in BC, then it is considered to be cost-effective.*

"*Assessing cost-effectiveness against the 'LRMC of new clean energy resources' is also consistent with the Demand-Side Measures Regulation, which requires the economic benefits of DSM plans to be calculated based on the LRMC from clean or renewable resources*.

"...*The Panel is further concerned with FortisBC's shorter term perspective given that FortisBC has stated that its generation is insufficient to meet its aggregate load. Specifically, FortisBC is in a capacity surplus situation, but has an energy shortage. The energy shortage is 4.9 GWh in 2015 and 6.4 GWh in 2016, and grows to an 82.2 GWh energy shortage by 2024.*

"*It may well be that the most cost effective generation to meet this shortage is self-generation, which could be a benefit, in the long term, to all ratepayers*" (G-27-16, 6.1.3 Giving a value to a cost effective energy alternative, pp 18-19).

<u>Based on this finding by the Commission panel in G-27-16 I am not persuaded by the thrust of CEC's Final Argument that FBC's entire LTERP should be rejected in favour of a greater emphasis on purchase of market power, as I believe that adoption of such a proposition leaves the Company more vulnerbale to the ups and downs of market place pricing, and fails to develop long term production capacity self-sufficiency in British Columbia from both SG and DG CGs customers of FBC as envisioned by the *CEA* and Action #25 of the 2007 Energy Plan</u>.

Further, the proposed rate of $48 per MWh for NM NEG is actually lower than the acknowledged levelized unit cost of $51 per MWh for market purchases, and of $50 per MWh for BC Hydro's RS 3808 PPA Tranche 1 purchase price over the next twenty years (B-1, Appendix J, Market Purchases, p 42).

Contrary to the Final Argument at 157 (where the Company opposes the submission of James Greavitt of Energy Futures Group Inc [EFG] that calls for 'measures and incentives in specific geographical areas'), the Commission has specific power to set rates in relation to section 2 (b), (c), (d), (g), (h), (i), (k) and (l) of the *CEA* in accordance with legislated powers granted it under 60 (2) and (3) of the *UCA*:

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility...for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics".

Further to FBC's critique of EFG and other intervenors at 132 of its Final Argument, 2(b) of the *CEA* needs to be considered in parallel with 2(g) – specifically as it relates to the switch from natural gas home heating and the switch from fossil fuel vehicles to electric vehicles (EV), and not just in terms of current household, commercial and industrial electrical consumption and load growth.

In this regard FBC needs to be cognizant of the fact that a number of European countries, as well as India and China, have now set dates by which sale of new fossil fuel vehicles will be phased out, ranging from as early as 2025 to 2040. In addition California is now considering joining them. In that sense EFG's recommendations make perfect sense and should not be dismissed out of hand as FBC has tried to persuade the Commission to do, especially in light of the fact that the new BC government has just appointed a 22 member climate change advisory panel that has to report back on how British Columbia can achieve a 40% reduction in greenhouse gas emissions over the next 13 years.

Unlike BC Hydro, FBC has not yet been required by the Commission to develop a clearly articulated DG program, especially an integrated NM policy. <u>As a consequence small local governments, small businesses and individual households, in the remote and rural portions of the FBC service area, are being placed at a huge disadvantage compared to those who live in the BC Hydro service area, especially as it relates to developing and implementing a clearly articulated transition from the use of fossil fuel energy. Self-Generation, coupled with energy efficiencies and conversion of vehicles away from fossil fuels, are some of the few options that remote and rural British Columbians have open to them, given that they cannot lessen the distances between, and sparseness of, their community populations.</u>

Further, the Business Herald reports that the National Energy Board's latest findings have determined that:

"*In any scenario, wind energy production will at least double and solar energy production more than triple over the next quarter century, the board projects. It also expects electric vehicle sales to grow to three per cent of all vehicle sales by 2020 and 16 per cent by 2040.*

"...Under the high technology scenario, the NEB says electric vehicle sales would soar to six per cent in 2020 and to 47 per cent by 2040.

"There are some nations, notably Great Britain and France, that intend to ban the sale of gas-powered vehicles by 2040..." (Business Herald, October 26th, 2017 – http://thechronicleherald.ca/business/1514873-canadas-energy-regulator-says-demand-for-fossil-fuels-will-max-out-in-two-years).

In conclusion we submit, in accord with FBC's own submission to the Commission panel as quoted in G27-16, that:

"*...should interveners or the Commission wish to explore the extent to which FBC may rely on self-generation in the future, the appropriate venue for the discussion is during an examination of the Company's resource plan*" (G-27-16, 7.1 Load displacement projects and DSM, p 49).

Our household requests that an analysis be so undertaken as it relates to DG and the NM program in particular.

<u>Our Personal Journey Towards Energy Self-Sufficiency and Fossil Fuel Reduction</u>

Our household has been a customer of FBC and its predecessors since August 8th, 1987, and generally speaking the delivery of electricity, given all the challenges of supplying electricity in the mountains of south east BC, has been excellent. After a heated exchange around installation of smart meters (related to the fact that my partner has multiple-chemical sensitivities and is on a CPP disability pension), we were able to reach a compromise agreement with FBC on where to install a smart meter on our property in April 2015. We also chose to join their NM program at that time.

To date we have invested over $30,500 in our self-generation system while, according to (i) and (iv) of the DSM Regulation Definition, we qualify as a “low-income household” (*Utilities Commission Act*, Demand-Side Measures Regulation, Definitions: http://www.bclaws.ca/Recon/document/ID/freeside/10_326_2008#section1). In addition we gave up owning our own vehicle over a decade ago, are members of the Kootenay Carshare Co-op, and use public transportation/ride sharing as our first option.

Since 2006 my partner and I have been attempting to achieve energy self sufficiency in accordance with the objectives of section 2(a) of the *CEA*. Between that year and 2014 we reduced our average daily grid consumption of electricity, through adoption of various DSM and energy savings measures, from 17.03 kWh to 8.93 kWh (Appendix A).

In the first five billing periods of 2017, through use of our own solar PV production, we have now reduced gross grid purchases to 6.92 kWh per day – a further 22.5% reduction. Net consumption of grid energy after additional transfer of kWh from our DG solar PV production system to the FBC grid in the first five billing periods of 2017 was 1.09 per kWh. This represents a 65.3% reduction in grid consumption since 2014, and an overall 93.6% reduction since 2006.

In contrast, at 142 of their Final Argument, FBC celebrates the fact that:

“*...under the High DSM scenario, FBC’s energy savings reach 0.8 percent of sales in most years of the planning horizon*” (Final Argument, 142).

Between 2006 and 2014 our household averaged a 5.95% reduction per year implementing DSM and energy savings measures, and from 2015 to 2017, under the NM RS 95 tariff, we have thus far achieved a further net grid purchase reduction of 15.3% per year (Appendix A). While in 2006 our household consumed approximately 51.8% of what the average FBC residential household used in electricity in 2016, in the first five billing periods of 2017 it is now just 3.3% (Final Argument, FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No. 3698875, 64).

Our household, and our neighbours here in Kaslo and the surrounding Electoral Area D who have joined either FBC's or BC Hydro's NM programs, are personally implementing the objectives of sections 2 (a), (d), (i), (k) and (l) of the *CEA.* Of 7 FBC NM customers in the Kaslo area, 2 are EV owners, representing half the EV owners currently in the community.

My approximate estimate is that 5% of the households in north Kootenay Lake have installed some kind of solar PV or micro hydro electrical generation system – much of them self-built and self installed. However only around .7% have joined either the BC Hydro or FBC NM available programs. Currently the size of NM systems in the BC Hydro service area is roughly double that of those being built in the FBC service area. The provincial average for solar PV penetration thus far is .002%.

Between 2015 and 2017 our household has specifically reduced “*the energy demand a public utility must serve”.* We did this by lowering our dependence on FBC grid electricity with a 3.9% per year reduction by substituting our own solar PV production for the Company’s grid electricity, and by transferring our solar PV production to the FBC grid for an 11.4% per year reduction.

In effect FBC's NM program is a “demand-side measure” as found within the definition of section 1(1) of the *CEA,* and as such should be governed by the requirements of section 44.1 of the *UCA*:

“*demand-side measure"* *means a rate, measure, action or program undertaken*
(a) to conserve energy or promote energy efficiency,
(b) <u>to reduce the energy demand a public utility must serve</u>, or

(c) to shift the use of energy to periods of lower demand” (*CEA*, Definitions 1(1)).

In fact FBC acknowledges this when it states:

“*DG can be considered both a supply-side or demand-side resource*” (B1, Appendix J, 3.4 Rooftop Solar Power [Distributed Generation], p 41).

Slightly earlier on the same page, FBC explains why it believes that DG/NM can be considered a “*demand-side resource*”:

“*If significant in amount, DG can also help utilities avoid transmission and distribution system upgrade costs, reduce line losses and reduce system energy requirements. The increasing popularity of distributed solar can result in more buildings and/or homes reducing their energy consumption*” (B1, Appendix J, 3.4 Rooftop Solar Power [Distributed Generation], p 41).

In relation to the requirements of 44.1 of the *UCA,* FBC's NM RS 95 tariff/program, however, there is no evidence that, within the meaning of section 2(c) of the *CEA,* FBC is following the requirements of 19(1)(ii)(b) of the *CEA*, in that FBC has, thus far, failed to provide sufficient information with regard to any planning target or firm purchase of DG (especially NM renewable energy) under the Company's proposed LTERP and LTDSMP time frame currently under discussion in this hearing.

<u>In relation to section 44 (6), (7) and (8) of the *UCA*, it is submitted that the Commission should consider not approving that part of the LTERP and LTDSM as it relates to the DSM program until FBC has submitted a comprehensive proposal with regard to integration of a long term plan and a purchase price for DG, including NM NEG, within the proposed current LTERP and LTDSM time frame</u>.

Further, contrary to its Final Argument at 71, FBC has not considered the NM program as a cost effective mechanism to help natural gas customers switch to electric heating as per the requirements of 44.1 (2) (c) and (e) of the *UCA,* regardless of whether or not fuel switching is now outside the DSM program after the March 2017 Greenhouse Gas Reduction Regulation (GGRR) amendments (in relation to the objectives found in 2 (g) of the *CEA*, for example). A review of the empirical evidence contained in “2016 NM#1 FortisBC Electrical Charges and Net Metering Transfer Values" clearly demonstrates the potential for natural gas heat customers enrolled in the NM program being able to partially or completely offset their purchase of Tier II level electricity with self-generated renewable solar PV energy or some other renewable or clean source (C10-8, Ibid).

Currently while FBC sees absolutely no role for its NM program within the current LTERP and LTDSMP, it is obvious that a more thorough cost-benefit analysis of fuel switching, using the RS 95 tariff/NM program, would refute FBC’s Final Argument as made at 71. Further, a considerable number of FBC electric heat customers, especially those who cannot access natural gas or other sources of heating, are very concerned about their high cost of winter heating bills. Again the empirical evidence provided from the 2016 FBC bills of NM#1, who has a geothermal system, clearly demonstrate that enrollment in the RS 95 tariff/program would assist those customers to offset the high cost of their winter bills as well.

Our household, as an example of that prospect, currently uses wood heat at a cost of $750 per year for 3 cords (though we are wired for electric heat). As we get older we are considering switching to electric heat in the shoulder seasons providing we can keep the level of consumption below Tier II. And, if we could stay within Tier I levels, we would switch over completely to electric heat as that would improve air quality both inside our house and outside in the neighbourhood. Again the Commission should not be persuaded by FBC’s dismissal of EFG’s proposal that the Company needs to consider environmental factors, both in terms of GGRR and winter air quality issues that exist within the FBC service area. And we do not agree that FBC should be allowed to wait until the next LTERP before starting to deal with the March 2017 GGRR amendments, as implementing reduction of greenhouse gas emissions is a stated priority of both the government of Canada and British Columbia. I am therefore persuaded by and concur with the reasoning made by CEC in its Final Argument at 91–94.

In conclusion, thus far the Kaslo group of NM customers has been unable to persuade the Commission to assist them in organizing any kind of face-to-face discussion with FBC around DG, and the NM program in particular. As a result, the potential for DG growth and development, and NM in particular, within the FBC service area is being retarded contrary to the stated objectives of section 2 of the *CEA* and Action #25 of the 2007 BC Energy Plan.

Is There a Case to be Made for DG, Especially NM, Within the Current LTERP and LTDSMP?

Between 95 and 102 of its Final Argument, FBC outlines its reasons and arguments as to why DG and NM specifically should not be considered within LTERP. At 102 FBC states that, because of amendments made to the RS 95 tariff in G-199-16, the NM program cannot be considered as a supply side resource, but does not say that it should not be considered as a demand-side resource. Subsequently FBC rejected that part of the Order requiring it to re-write the tariff wording within 90 days. Instead, in March 2017, it filed an appeal that would, if successful, grant the Company the right to remove customers from the NM program for consistently producing NEG.

For the record, in 2009 FBC produced a pamphlet that encouraged customers to attend Open Houses in Castlegar and Kelowna on March 17th and 19th respectively, and promised that NEG production under the NM program would be:

"...*valued at retail*" (Appendix A, Scarlett Final Argument, FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No.3698875).

The exact same promise made on that 2009 pamphlet was verbally made to me by a senior member of the FBC staff (listed on that pamphlet) in our backyard in May 2014, and similar commitments were made to all the other NM customers that I have spoken to in the Kaslo area. Regardless of whether an NM customer should or should not be allowed to consistently produce NEG (the subject of intense discussion in another hearing), the fact remains that any customer who produces electricity at a nameplate capacity of 50 kW or less and 750 volts or less, by FBC's own admission, has no other program or tariff to apply to join. And in its application for Phase II of the Self-Generation Program (SGP), now suspended by Order G19-17, FBC noted that the Commission panel in the SGP Phase I Order agreed that Generator Baseline (GBL) Guidelines should only apply to SGs above 50 kW and 750 volts (B-1, Applicability of Self-Generation Customers, 2.4.1 Eligible Customers, FortisBC Inc. Self-Generation Policy Stage II Application ~ Project No.3698820, p 13, line 13 to 21).

<u>There is therefore a distinct need for the Commission to consider directing FBC to develop a tariff and program for purchase of electricity from customers with a generation capacity of 50 kW or less and 750 volts or less, in line with Action #25 of the 2007 Energy Plan, noting that the Commission in Order G-199-16 has absolutely determined that the RS 95 tariff is only an offset program and nothing more</u>.

That said, our household first produced 70 kWh of NEG in the June 2016 billing period and followed that up with 350 kWh in August 2017, and 144 kWh in October 2017 (Appendix A). A neighbour, NM#1, produced 1.273 MWh during the six billing periods of 2016, while two other customers in the residential section of the NM program in 2016 produced approximately145 MWh between them (C10-8, Ibid and Final Argument, FortisBC Inc. Application for Reconsideration and Variance of Order G-

199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No. 3698875, 42). All in all I am aware that, of seven NM customers in the Kaslo area, five produce NEG during one or more billing periods and/or during all of the calendar year.

So, given that the majority panel in G-199-16 declined to deal with the issue of NEG purchase and small scale DG in general, and that the SGP Phase II hearings have been suspended, it is necessary for this Commission panel to consider the plight of some 233 RS 95 tariff customers who have been in a state of limbo for over fifteen months regarding NEG and their right to produce it and at what price.

That said, FBC, at 96 of their Final Argument, state that:

"*As such, DG is inherently unpredictable and FBC does not consider it to be a secure or reliable firm resource for long term planning purposes*".

Between 2006 and 2014 our household averaged a 5.95% reduction per year implementing DSM and energy savings measures, and from 2015 to 2017, under the NM RS 95 tariff, we have thus far achieved a further net grid purchase reduction of 15.3% per year (Appendix A). While in 2006 our household consumed approximately 51.8% of what the average FBC residential household used in electricity in 2016, in the first five billing periods in 2017 it is now just 3.3% (Final Argument, FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No. 3698875, 64).

Between 2015 and 2017 our household has specifically reduced (in accordance with the definition found in 1.1 of the *CEA*) "*the energy demand a public utility must serve*" by lowering our dependence on FBC grid electricity through a 3.9% per year reduction by substituting our own solar PV production for FBC grid electricity, as well as through an 11.4% per year reduction by transferring some of our solar PV production to the FBC grid. As can be seen from Appendix A, since enrolling in the NM program our household's gross grid consumption has either been stable or dropped slightly, with impact due to weather variances being strongest in the spring, summer and fall, and not the winter billing periods.

Contrary to FBC's statement at 96 of its Final Argument, the empirical evidence from our household's consumption patterns demonstrates that FBC's reasoning simply does not hold up. Before the Commission is persuaded by the Company's claims in this matter, it should require them to produce empirical data from an analysis of the aggregate consumption of their own NM customers' consumption patterns that differs or refutes our consumption experience.

At 42 of its Final Argument in the Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 hearing, FBC states:

"*These customers both had NEG in every billing period and had negative net consumption of -114,386 kWh and -30,610 kWh, respectively...*"

The Company is in fact claiming in one hearing that two NM residential customers should not be allowed to produce 145 MWh of electricity per year, and then claiming before a second Commission panel that "*DG is inherently unpredictable and FBC does not consider it to be a secure or reliable firm resource".* Clearly if just two DG/NM CGs can provide to the FBC grid 145 MWh of energy in a year, the statement that DG and NM in particular do not have the potential to be a "*secure or reliable firm resource"* is not an accurate assessment of DG or the NM program's potential.

I can only reiterate that the Company is contradicting its own findings as stated in its own application to the Commission in this hearing:

“*If significant in amount, DG can also help utilities avoid transmission and distribution system upgrade costs, reduce line losses and reduce system energy requirements. The increasing popularity of distributed solar can result in more buildings and/or homes reducing their energy consumption* (B1, Appendix J, 3.4 Rooftop Solar Power [Distributed Generation], p 41).

Let’s, however, do the math. The 114.386 MWh, cited above, comes from a micro-hydro system with a nameplate capacity of 20.5 kW. Thus the 114.386 MWh is the production left over after offsetting the consumption of two residences from a system that is running twenty-four hours per day, three-hundred and sixty-five days per year – that is consistently producing for sale just 13.06 kW per hour.

Clearly what FBC is presenting at 96 of their Final Argument is unsubstantiated reasoning, when what is needed is empirical evidence that shows the exact number of kWh of electricity being transferred in aggregate from DG/NM CGs to the Company’s grid annually, by season and by hour of day, if necessary, so as to properly benchmark the potential of DG and the NM program.

To date the only figures I have seen are 3,296 MWh from three SG producers: Tolko, Celgar and Nelson-Hydro, and 310 MWh over the same period from all the NM CGs in 2016 combined (B-11 BCUC IR#2.72.4). That would mean that two residential NM customers in 2016 provided 46.8% of all the electricity transferred, and one small commercial customer a further 51.9%, which would leave the remaining 83 NM CGs only providing 1.3% of the MWh transferred from the NM program in 2016 (Final Argument, FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No.3698875, 42 and Electric Tarifff, BCUC No 2, Schedule 20-Small Commercial Service, Eleventh Revision of Sheet 3: https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBCElectricTariff.pdf).

Again FBC should be required to produce the total aggregate of what was and is being transferred from DG/NM customers in 2016 and 2017, before the Commission is persuaded as to the veracity of the Company’s figures, and further the Commission should consider that, at the current rate of growth in NM program enrollment, the electricity being generated and transferred could in fact eventually be equal to the volume and value as that provided by the three SG producers.

The RS 95 customers and DG producers at or below 50kW and at or below 750 volts should therefore be afforded the same considerations and rights as those considered and directed to be developed by the panel in Order G-27-16. To do otherwise would be to afford SGs special privileges not afforded to all CG DGs and would be discriminatory towards RS 95 customers, contrary to the provisions of section 59 of the *UCA*.

FBC then goes on to say in 96 that:

Solar photovoltaic (PV) installations, which are one of the primary sources of customer DG, also provide virtually no capacity during peak winter demand periods and their proliferation could lead to oversupply issues in the spring and summer periods”.

In the December 2005 and February 2006 billing periods, our consumption of grid electricity was 2.452 MWh, which by December 2014 and February 2015 had shrunk to 1.21 MWh (Appendix A). For the two winter periods when we were enrolled in the NM program, 2015/2016 and 2016/2017, we had net grid consumption of .889 MWh and .934 MWh respectively.

This represents a further reduction for our household of 13% in 2015/2016 and 11% in 2016/2017 (remember, the DSM program is achieving an overall .8% per annum reduction), and an overall reduction of 62% and 64% in the winter months since 2005/2006. Thus, even in winter, when comparing our NM program savings to those of the DSM program, the overall savings are likely to be larger for the NM program.

To this we would add our fall October billing period. In October 2005 this was 1.048 MWh, and .445 MWh in 2014. Subsequently, after enrolling in the NM program, it has been reduced to .162 MWh in 2015, .108 MWh in 2016, and a surplus of .144 MWh in 2017. So by the fall of 2017 we have reduced our net grid autumn consumption by 113.7% as compared to 2006. Currently our December billing period net consumption, in 2017 (after 25 days), is set to be over 70% below December 2005.

In fact, during five of ten winter peak demand days in the winter of 2017 (as determined by FBC), our household, while purchasing 43 kWh, transferred back from our solar PV production system 23 kWh – which offset 53.5% of gross grid consumption on those peak demand days. What FBC did not take into account with its reasoning at 96 is that colder, higher consumption demand days often coincide with the clearest and sunnier skies in winter, so solar PV does have a role to play around offsetting peak demand in winter.

In fact, of twelve days in January/February 2017, our consumption was 8 kWh per day, while transfer was 4.75 kWh for an offset rate of 59.4% – for 20% of the days, the coldest ones, in those two months. It is therefore submitted that FBC, which has provided no empirical evidence from its DG and NM customers' aggregate consumption and transfer/offset patterns, is not accurate in its assessment of what solar PV can provide in winter across its entire service area. FBC is even more inaccurate on what the NM program could provide from small micro-hydro renewable resources, whose operations run twenty-fours a day, seven days a week – such as what a mere 13.06 kW per hour can amount to if production is continuous over a year: 114.386 MWh.

In addition, attached to our solar PV system are twelve 2 volt silicon salt batteries, of which our household would be more than willing to make available up to 20 volts of power (we can drain our batteries 100% and re-charge them fully and they have a life expectancy of 20 years) during any peak demand situation that FBC might have (C10-8, Silicone Batteries Inc). So, while it is true that we cannot always dispatch electricity during the peak demand times of 4.00 PM to 9.00 PM from our solar PV production system, it is completely erroneous for FBC to claim that we could not dispatch some stored electricity from our system upon request of the Company during those same peak demand times (B-1, Appendix J, Technical Attributes, p 4). This underscores the fact that many of FBC's broad sweeping statements in this hearing have been made without the Company surveying and/or talking face-to-face with their DG/NM CGs to confirm what their system capabilities are and what a customer might be willing to undertake.

In addition, for example, our household now only has two appliances that are directly attached to the grid: the hot water heater and the kitchen stove, both of which we can directly control when we draw energy for them. Nearly half a decade ago we asked an electrician to install an on/off switch in the kitchen for our hot water heater, and so for almost five years half of our daily electrical needs are drawn off the grid before 8.00 AM in the morning. A further one or two kWh are sometimes drawn off the grid between 11.00 AM and noon, but nothing more than that before 7.00 PM at night.

We also believe that we can control when our system draws energy from FBC's grid to re-charge our batteries (when they are not being re-charged by our own solar PV production), but are hardly likely to want to do any of the above if the Company is simply going to come before the Commission and argue for the lowest possible purchase price for our electricity, without acknowledging the avoided cost valuation of that power as it proposes to do for the three SGs in tariffs 30 and 31.

When our household joined the NM program we thought that we were partnering with FBC and looked forward to discussing ways that our system could enhance the value of electricity that we were transferring onto their grid. Instead what we have witnessed and experienced over the last fifteen months is FBC making statements to the Commission without ever surveying or meeting face-to-face with its DG/NM customers.

In contrast BC Hydro NM customers have been surveyed for their opinion on how the program can be improved, receive regular email updates, and have a web page that they can visit to learn about updates to the program in which they are enrolled. The Commission is asked to consider which program is most likely to be more persuasive in attracting more customers who wish to engage in demand-side measures and energy savings in general.

At 39 of its Final Argument, FBC acknowledges that both its winter and summer peak demand will continue to grow at an annual compound rate of 1%, and yet the Company continues to argue that solar PV and other renewable sources of clean energy have no role to play in lowering that summer peak demand. Again, if solar PV is so "*inherently unpredictable",* why is the Company then making statements to the Commission in the same section and on the same page of its Final Argument that there is an equal danger of "oversupply" (Final Argument, 96)?

FBC then continues at 97 by stating:

"*NM customers can reduce their energy consumption charges to zero or even negative and because FBC's volumetric rates include recovery of fixed costs, these customers are effectively subsidized by the rest of FBC's ratepayers for a portion of their contribution to the fixed costs of the utility system they use and rely upon.*

"*This presents issues of inequity between customers that will become more pronounced if DG does proliferate to the point of materially reducing load".*

At 180 of their Final Argument FBC states:

"The LRMC of $100.45/MWh for DSM purposes was estimated as part of the portfolio analysis FBC conducted for the LTERP. It reflects the LRMC of a portfolio of resources without any DSM: Portfolio B1, which includes wind, biomass, biogas, run-of-river, and market purchases out to 2025".

In the August 2017 billing period our household was credited $101.17 per MWh for 350 kWh of NEG, which offset the Basic Charge of $32.09, the GST of $1.60, and left a credit of $1.72 to be forwarded to the next billing period (Appendix A). In the October 2017 billing period our household paid $17.40 after transferring 144 more kWh of NEG, instead of the $33.69 that we would have paid if there had been no credit for the excess electricity we transferred. We also used the $1.72 credit from the August billing period.

In 2016 FBC calculated that it was retailing each MWh of residential electricity (inclusive of Tier I, Tier II, Basic Charge and GST) for $134.8 (B-10, Shadrack IR#1.20.a, FortisBC Inc. Net Metering Program Tariff Update Application ~ Project No.3698875). However, since the overall rate for both electricity and Basic Charge have increased in 2017, it is estimated that retail rate is now $135.81 – using the same parameters.

So, while we offset our household bill with 350 kWh valued at $33.69 in August, and 144 kWh valued at $16.29 in October, FBC earned $47.53 in the August and $19.56 in the October billing periods retailing that NEG. In addition, since our NEG electricity and all of our transfers of kWh to the FBC grid are retailed in the neighbourhood where they are transmitted, there are no transmission line losses, in effect our electricity comes with a 1% to 8% premium that FBC has estimated at anywhere from $1.50 to $4 per MWh (B-11, Shadrack IR#1.1.ii and 2, FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No.3698875).

In this context FBC also acknowledges that there are wheeling costs that have to be added to the transmission line losses as follows:

"*Wheeling costs within B.C. are based on the BC Hydro Open Access Transmission Tariff (OATT), effective April 1, 2016. This equates to $8.85 per MWh for wheeling costs and 6.28 percent for line losses, assuming hourly rates*.

"*...For FBC market imports from the Mid-C market hub, FBC has assumed the cost for this transmission is based on the Bonneville Power Administration (BPA) transmission and loss rates , effective October 1, 2015, escalated based on inflation. These equate to about $7.50 per MWh for wheeling costs and 3 percent for line losses*" (B-1, Appendix J, 2.2.2.1 Financial Assumptions, Wheeling Costs, pp 7-8).

Further, if the retailing of our electricity does not use the transmission lines for delivery to point of sale, it is submitted that there must be a cost differential between delivery of, say, BC Hydro RS 3808 PPA Tranche 1 and NM energy purchased under the RS 95 tariff. Thus far FBC has not disclosed what any of these cost differentials are, and as a consequence we are simply not persuaded that any subsidization of our account is occurring. To the contrary, I am starting to feel that it is our household that is subsidizing FBC.

In contrast to FBC's position, it is submitted that EFG's testimony, within the context of section 60 (2) and (3) of the *UCA*, particularly as it relates to service in remote and rural geographical locations like the Kaslo service area, is an accurate reflection that the Company needs to:

"...m*odify the transmission planning process to consider non-wires alternatives to construction, including energy efficiency and demand response initiatives, on an equal footing with traditional poles and wires solutions* (C5-5, p8).

"Utilizing and reporting on the results of the modified TRC test that incorporates values for the environmental benefits that result from energy efficiency (C5-5, p13).

"Developing and using marginal line losses in DSM cost-effectiveness assessments rather than the average line loss values that are currently employed (C5-5, p13).

The following are examples of statements made by FBC in response to IRs from Shadrack that illustrate and confirm Mr Greavatt's testimony:

FBC cannot comment on the assertion regarding the relative cost of delivery to remote/rural locations versus highly concentrated urban areas because FBC does not examine costs in this way (B-9, Shadrack IR#1).

"...*FBC does not conduct a COSA in consideration of regional differences and is therefore not able to provide the cost comparisons as requested* (B-9, Shadrack IR#1.6.i).

"*NM systems could in theory result in the deferral of future capital growth projects. However, given the uncertainties associated with non-firm power produced by customer DG, it is not considered a practical alternative to the firm capacity and the more certain construction timelines associated with conventional infrastructure upgrades. The primary issues are that net generation produced by NM customers is often intermittent and is unlikely to peak concurrently with system peak load*" (B-9, Shadrack IR#1.6.iv).

In its defence, the Company claims that its policy is primarily predicated on maintaining a "bottom line" that is in the best interest of FBC and all its other customers, as instanced by these two answers to

IRs from Shadrack:

"*FBC balances its LTERP objectives but places emphasis on the first objective of ensuring cost-effective, secure and reliable power for customers*" (B-9 Shadrack IR#1 6.ii).

"*The question is focused only on costs, without considering the revenue that would be lost as a result of the load reduction. At the level of rates and cost for energy as they currently exist, and will exist for the foreseeable future, the loss of load as described would lead to an increase in rates to all customers*" (B-9 Shadrack IR#1.6.v).

In response to this last statement, it is submitted that in the first five billing periods of 2017 our household paid FBC $191.52 for electricity and Basic Charge, and an additional $12.15 in GST, which results in a cost of between $91.94 per MWh and $97.78 per MWh for the gross purchase of grid electricity. However this rises to between $583.9 per MWh and $620.95 per MWh after factoring in the transfer of 1.755 MWh from our solar PV production to the Company's grid.

While our household has so far earned $177.55 in credits in 2017 from the transfer of 1.755 MWh to FBC's grid, we still pay between $191.52 and $203.67 for .328 MWh for net purchase of grid electricity. Meanwhile FBC first earned $191.52 from our household (primarily the cost of the Basic Charge), took in $12.15 for GST, and then retailed 1.755 MWH for a value of $238.34. It is therefore inaccurate for FBC to say that, when an NM customer reduces his or her personal net consumption, the Company's overall revenues decline, because while we are paying $191.52 for the net of .328 MWh of electricity, the Company in fact earns $429.86 from sale of both what we purchase from and transfer to them at a price per MWh of $206.36. While the Company made $429.86 selling us the net of .328 MWh and retailing 1.755 MWh transferred to them from our production system, they would have had to sell us 2.144 MWh to earn the same amount if we were not enrolled in the RS 95 NM program.

Unless the Commission believes that NM CGs who transfer and/or sell electricity from their own production should also pay for the transmission of that electricity, the fixed costs for that electricity should be acknowledged as in fact being covered by the retail price that the Company receives for the sale of that electricity. Unless the Commission is persuaded that the Company has adequately explained how they are allocating what specific costs from the retail of that transferred NM electricity, the Commission should not accept FBC's claims that subsidization is occurring. FBC's statement in its Repy Argument that it does not accept my calculations does not answer the question as to how those revenues that are collected are allocated and to what costs (Reply Argument, FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No.3698875, pp 44- 50).

Similar results to ours were found when calculating the purchase and sale prices from NM#1's FBC bills for 2016 (C10-8, Ibid). While FBC has claimed that average NEG payout in 2016 was $124.5 per MWh, not the $101.17 that our household was credited for, it is not clear if that claim is for the three customers for which the Company actually wrote NEG cheques, or the five customers who had greater Tier II NEG than they purchased.

Further, while FBC reports that in 2016 it paid out $21,252 to two residential NM customers for production of approximately 145 MWh, it inadvertently forgot to explain that it also earned $19,545 ($134.8 MWh) from the retailing of those same MWh (Final Argument, Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision, 42). These two customers at the time represented 2.3% of all the enrollees in the program, and the amount of the cheque paid out represents a cost to the 114,600 residential customers of 18.5 cents each. By mid 2017 only two residential customers had been paid $18,375, which represented .86% of the total number of enrollees in the NM program at a cost of 15.8 cents to each of the 114,600 residential customers.

What has not been ascertained from the Company, however, is the total number of MWh transferred in aggregate by all 86 program participants in 2016, and the total value of those MWh transfers in aggregate by all 233 program enrollees so far in 2017. To illustrate this point the Commission is asked to consider FBC's DSM report for 2016. (APPENDIX A – DSM PROGRAMS COST AND SAVINGS SUMMARY REPORT Table A – 1: FBC DSM Summary Report for Year Ended December 31, 2016, FortisBC Inc. (FBC) Electricity Demand-Side Management (DSM) 2016 Annual Report – https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/170331_FBC_2016_DSM_Annual_Report_FF.PDF). What is reported is that, in the residential section, approximately $29 per MWh was spent reducing consumption by 12,538 MWh. Like FBC, one could draw attention to the fact that the appliance section of the DSM residential program cost $137 per MWh while only reducing consumption by 242 MWh in 2016, instead of noting that 8,607 MWh were reduced in the lighting program at a cost of $11 per MWh.

Highlighting what the Company is paying out in cheques to two or three customers, out of a total of between 86 and 233 enrollees in 2016 and 2017, should not be a persuasive way for the Company to explain what it is spending per kWh on the whole NM program. It also does not disclose what the Company is actually earning from retailing the aggregate total of all kWh transferred from RS 95 NM CGs. Consequently the Company does not disclose the net cost of the NM program and the aggregate dollar ($) value of the reduction and transference of MWh as proposed should happen under Action #25 of the 2007 Energy Plan.

Again, without having the empirical evidence from the Company, it is impossible to determine if the experience of our household of being credited $101.17 per MWh, for 1.755 MWh, while the Company earns $429.86 on the 2.083 MWh it sells to us and retails from us (.328 + 1.755) – $206.37 per MWh – is the norm or an anomaly. Our household considers an overall 5 MWh reduction in net grid consumption in the first five billing periods of 2017 a major accomplishment – one for which any residential household that achieves that level of energy savings should be fully credited, in a similar manner to that in which the Company proposes to credit SGs in tariff 30 and 31 for their DSM energy efficiencies.

At 98 FBC continues by stating:

"...it appears that his estimates do not included any operations and maintenance (O&M), interest, or financing costs or use of discount rates. Accordingly, his evidence does not provide comparable values to measure against the UECs and UCCs of resource options provided by FBC in the LTERP".

To date all of the systems for which I have found data are small scale DG systems that have had no O&M costs and that were bought outright and therefore had neither interest nor financing costs nor discount rates. Further, a review of Table 8 in the FBC's application does not state either size or length of operation life for the plant and equipment, and I remind the Commission that FBC is claiming a forty year amortization period for its solar PV farm pilot project in Kelowna when Sun Mine in Kimberley (four times the size of the Kelowna pilot project) has a life expectancy of only twenty-five panel years – the current industry norm (Final Argument,108).

The truth of the matter is that large DG systems like FBC's proposed solar PV farm pilot project will be more expensive if the Company is going to put up the capital and operate such projects itself, as noted in the discussion of solar PV production in the Final Site C Report (Appendix A – Alternative energy and capacity sources, 1.2.7. Solar, pp 47-53, British Columbia Utilities Enquiry Respecting Site C: Final Report to Government of British Columbia, November 1st, 2017):

"*The Panel is concerned, however, that BC Hydro's utility solar cost estimate of $133/MWh to $182/MWh may not have been updated to reflect BC Hydro's estimate of the current capital cost of* *utility solar at $1.64/W and so may have prematurely excluded utility solar PV from further consideration*" (p 49).

Current costs are provided in a table at 50: $1.69 in 2018, and projected at $1.13 in 2025 at 2018 dollars, and $1.02 in 2018 dollars in 2035.

In contrast at 52 the panel notes:

"...*residential solar PV (5.7 kW) and medium general service solar PV (200 kW) is projected to decline below the Tier 2 rates by 2025 in the regions of the Province having greater solar potential, including the East Kootenay (i.e. Cranbrook), the Peace Region and Selkirk (Kelowna)*".

In "Updated Modified Table 8-1: FBC Demand-Side and Supply-Side Resource Options" I was able to cite empirical evidence that self-built and self-installed small DG solar PV production systems have cheaper Unit Energy Costs and Unit Capital Costs than FBC's proposed solar PV farm pilot project (C10-8). In fact even the non-customer installed Kaslo solar PV system, NM#4, came very close to matching FBC's Kelowna pilot project costs at 20 to 25 years amortization, and in fact was cheaper when a 40 year amortization time frame was used.

At 1.2.7.4. the Site C panel finds that:

"...*behind-the-meter' residential and commercial solar also have the potential to place downward pressure on BC Hydro's load forecast over time*" (p 52).

Thus, if FBC were to offer to its other residential customers NM-produced and purchased DG, based on a retail purchase price of $101.17 per MWh, that would be cheaper than FBC's own Solar Farm pilot retail price of $231 per MWh.

In contrast to the above option, SG customers are being given an option under the DSM program that is not open to NM customers when FBC states:

"*FBC will evaluate each DSM measure proposed by self-generator customers independently to determine how much of the project's energy savings accrue to the Company and will prorate the applicable incentive accordingly.*

"This approach is consistent with the scheme of the UCA and the DSM Regulation, under which the cost effectiveness of DSM is based on a utility's avoided costs. The TRC and Utility Cost tests both use the present value of the avoided costs from a measure – i.e. the utility's energy savings from a measure valued using LRMC, plus avoided infrastructure costs using the DCE – to determine cost effectiveness. Accordingly, paying DSM incentives to self-generator customers in proportion to FBC's avoided costs that result from a measure is supported by the governing legislation and, we respectfully submit, a reasonable approach" (Final Argument, 66-67).

FBC has not done that kind of "avoided-cost" analysis with respect to its NM program nor DG customers in general. In this regard we ask the Commission panel to consider the findings in Order G-27-16, specifically the discussion as found at:

6.1.2 Potential benefits
6.1.3 Giving a value to a cost effective energy alternative
7. Incenting Self-Generation
7.1 Load displacement projects and DSM
7.2 Energy Purchase agreements for incremental self-generation
8.0 Final Determination and Stage II Filing

Between 2006 and 2014 our household, for example, implemented a variety of DSM and energy savings measures such that daily consumption declined on average from 17.03 kWh to 8.93. Subsequent to joining the NM Program, it has declined in the first five billing periods of 2017 to a gross of 6.92 kWh daily, and 1.09 kWh net of transfers to the grid.

The current structure of the NM program, and for all DG/NM CGs, is such that we are only credited for the net of our gross consumption minus transfer of kWh to the Company grid. Thus, unlike the above proposal for SGs, NM customers get no credit for any DSM and energy savings measures that they adopt, including use of own production to reduce overall grid consumption. In the instance of our household, this amounts to a 10.11 kWh daily reduction for which we receive no credit (Appendix A).

Further, while we transfer to the Company's grid the net of reduction of 5.83 kWh daily, at par of what we pay for the energy portion of that bill, the Company is proposing that we should only receive 4.8 cents per kWh for any transfer above that. Meanwhile FBC acknowledges in its own application that market purchase levelized unit costs will be 5.1 cents per kWh, and that for BC Hydro's RS 3808 PPA Tranche 1 5 cents per kWh:

"...*levelized unit energy cost for market purchases is about $51 per MWh including transmission costs and losses from Mid-C*.

"...*PPA Tranche 1 Energy rate (as provided in Figure 2-11 of Section 2.5), with a levelized value of about $50 per MWh over twenty years*" (B-1, Appendix J, Market Purchases, p 42).

The Commission should only be persuaded by this reasoning if they are prepared to accept that DG/NM power is delivered at the same expenditure costs as market purchases and PPA Tranche 1 electricity. Such an acceptance would appear to contradict FBC's own assessment of DG in its application when they state:

"...DG can also help utilities avoid transmission and distribution system upgrade costs, reduce line losses and reduce system energy requirements" (B-1, Appendix J, 3.4 Rooftop Solar Power [Distributed Generation], 41).

Further, it is submitted that these avoided costs are not just found in the offset of purchase of grid electricity, but also in the delivery of DG/NM from point of purchase to point of sale in which the transmission lines are not used at all.

The rationale for slashing the price of NEG, even though our household is only credited $101.17 per MWh while the Company earns $206.37 on the MWh we both purchase and transfer to the Company, does not stand up to close scrutiny in light of some of FBC's own applications and submissions.

As instanced by the calculations found in Appendix B, this has to be the only pricing structure that our household is aware of in which a customer who purchases 5 MWh of electricity pays the same for commodity and infrastructure costs as someone who purchases 20 MWh – $17 more per MWh than if they consume 10 MWh and $6 more per MWh than if they consume 15 MWh (Appendix B).

We are unsure how this pricing structure promotes energy savings among residential customers and how it promotes investment in small scale DG/NM production. Therefore we think that the Commission should consider directing the Company to explain how this pricing structure promotes the objectives as stated in section 2 of the *CEA* and Action #25 of the 2007 Energy Plan, before approving the DSM portion of the LTERP and LTDSMP.

In this context we concur with the British Columbia Municipal Electric Utilities' (BCMEU) argument as reported by the Commission panel in G-27-16:

"*In the New PPA Decision (Order G-60-14), the Commission noted BCMEU's submission that there has been a lot of focus on the negative impacts of a self-generating customer serving its own load with embedded cost power while exporting its own self-generation; however, there has been little discussion of the benefits that could arise from an economic development perspective, if the role and responsibilities of self-generators was more clearly defined.*

In the New PPA proceeding, BCMEU stated that it is in the interest of its members and the entire province to encourage self-generators to add new generation and to encourage non-generators to add generation. BCMEU pointed out that the current economic incentive [in the FortisBC service area] to invest in new generation on a net of load basis is very low. The best incentive currently available is the ability to use self-generation to off-set load thereby avoiding power purchases from FortisBC at embedded cost rates" (G-27-16, 6.1 Net benefits of self-generation, p 15).

In contrast, a BC Hydro NM customer living 14 kilometers down the road from our household in Schroeder Creek, who offsets their Basic Charge with NM transferred MWh, only has to transfer .694 MWh per annum, whereas our household has to transfer 1.724 MWh to offset FBC's Basic Charge costs. And, if the price of NEG is dropped to $48 per MWh, we will have to instead transfer 4.011 MWh per annum. In comparison to the $192.52 with which FBC will credit our household, they will retail that same energy for $544.73. Thus we again ask: how will the $352.21 revenue differential be allocated and to what costs specifically?

We therefore ask the Commission to consider rejecting FBC's argument that the current NM price structure has the potential to cause subsidization, unless the Company is prepared to provide the empirical evidence with which to supports its position.

In contrast I concur with BC Hydro's analysis of FBC's self-generation policies as found in G-27-16:

"*BC Hydro submits that FortisBC self-generation policy excludes consideration of the potential role of new self-generation in FortisBC's long term resource planning, including opportunities for demand-side measures such as FortisBC implementing rate structures and providing funding for load displacement projects to encourage self-generation and reduce demand on the system. BC Hydro states that 'The BC Energy plan and the policy actions summarised in Appendix A of it, provide strong support for utilities in British Columbia to pursue all cost-effective demand-side managements programs, including load displacement'*" (G-27-16, 7.1 Load Displacement projects and DSM, p 48 and 49).

In that regard I further submit that the Commission panel findings in G-27-16 support my conclusions about FBC's lack of appropriate analysis for its position on use of both NM and DG as a resource, and for the setting of an appropriate pricing structure for those sources, when it states:

"*First, FortisBC submits that the practical reality is that it is not aware of existing cost-effective opportunities for the purchase of self-generation output, where cost-effective compares favourably to other available resource (power supply) options; however, FortisBC did not provide details on how it assesses 'cost-effectiveness'.*

"*BC Hydro on the other hand states that it evaluates cost-effectiveness relative to the provincial LRMC of new firm energy. As fully discussed in Section 6.1.3, the Panel has concerns with the way FortisBC's proposes to evaluate cost-effectiveness on* *a shorter term basis and those concerns and recommendation identified in Section 6.1.2 apply equally to these circumstances.*

"*Second, the Panel appreciates that FortisBC evaluates its various power supply options in the context of its resource plan. However, in the Panels view FortisBC's SGP should disclose how FortisBC will evaluate potential long term energy purchase contracts with self-generation customers when comparing it to other available resource options. The Panel notes that many of the benefits to self-generation listed by FortisBC could also apply when FortisBC purchases clean energy from its self-generating customer, especially when the electricity does not physically leave the plant site, as in the BC Hydro service area. Such benefits could include:*

- *electricity self-sufficiency, reduced greenhouse gas emissions,*
- *a reduction in the need for utility-provided network capacity,*
- *deferred or permanent reduction in the need for utility provided generation, transmission, and distribution capacity,*
- *reduced transmission losses,*
- *reduced environment impacts,*
- *improved reliability,*
- *avoided or deferred investments, and*
- *relieve transmission congestion*" (G-27-16, 7.2, Energy purchase agreements for incremental self-generation, p 51).

In anticipation of FBC's reply argument, I submit that what the Commission panel found in G-27-16 for SG CGs should equally apply to NM NEG and DG CGs in general (for production systems at 50 kW or below and 750 volts or less). To do otherwise would be to act contrary to the requirements of section 59 of the *UCA.*

The lack of a well thought out and understood policy towards DG and NM CGs in particular, including an appropriate evaluation of the avoided cost values of the electricity that our household supplies to the Company, has become a major source of contention between ourselves (and our neighbours who participate in the NM program) and the Company, in which I respectfully submit that the Commission has been remiss in not requiring FBC to provide a clearly articulated policy and a pricing structure that they have required of BC Hydro since 2004.

Conclusion To Final Argument

Since December 2005 our household has invested an average of $424.15 in each billing period in DSM, energy savings and net metering – offsetting that investment with 36.858 MWh of energy savings at a current estimated value of $51.79 per billing period. This has ranged from a low of $29.19 per billing period in 2007 to an average of $99.28 so far in 2017, in a current estimated pay back period of 57 years.

In this context our household (and our neighbours who are enrolled in this program) did not ask either FBC or the Commission to set the price for every kWh of NEG produced at retail, but that is the promise that the Company used to induce us into investing in their NM program before we enrolled (Appendix A, Scarlett Final Argument, FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No.3698875).

Yet within a year of our household investing thousands of dollars ($) in solar PV equipment and enrolling in the program, the Company had applied to the Commission to lower the price of NEG from retail to 4.8 cents per kWh or lower. Such a proposal by the Company appears to contradict the findings of the Commission in the issuance of Order G-27-16, the FortisBC Inc Self-Generation Policy

Application Phase 1, and I submit that setting a different policy for DG customers in general and RS 95 NM customers in specific, or continuing to have no policy at all, is discriminatory and contrary to section 59 of the *UCA*.

In the first five billing periods of 2017 we have paid FBC $191.92 for .328 MWh of electricity, while the Company has earned $429.86 from the sale of that electricity to us and retail of 1.755 MWh that we have transferred from our production to their grid. We are absolutely perplexed by the Company's claim, for which they provide no empirical evidence, that this transaction results in our household being subsidized by both the Company and other customers. Therefore, as a result of FBC's claim to the Commission, we urge the Commission panel to consider how it is going to set a fair price for NM NEG and small scale DG in general if it does not know how the Company allocates to costs the difference between the $191.92 that we pay them and the $429.86 that they earn from us: a difference of $237.94.

While we understand that this Commission panel is not dealing with whether NEG can be produced under the NM program, and to what limit, and whether NM customers can be removed from the NM program for producing NEG, we note that the Commission panel majority that issued Order G-199-16 declined to determine a price for NEG. Instead the majority panel indicated that either the SGP Phase II panel, this panel or a third panel should discuss both price and whether or not customers with production systems of 50 kW or less and 750 volts or less should sell electricity to FBC beyond the offset program under the RS 95 tariff.

Given our experience, and that of our neighbours, with the Company over the last fifteen months we no longer trust the Company to come before the Commission and ask for a fair price for purchase of our production unless there is both a clearly defined program and tariff administered by the Commission, none of which exists at this time. <u>We therefore ask that this Commission either Order a new hearing to set a defined price for production from DG systems at or below 50 kW and at or below 750 volts, or attach a settlement conference to this hearing to deal with this matter</u>.

Beyond the directive in Action #25 of the 2007 BC Energy Plan to "*appropriately recognize*[s] *the value of aggregated intermittent resources",* and legislated prescriptions delineated in section 2 of the *CEA,* the Commission has the jurisdiction under section 60 (2) and (3) of the *UCA* to set a fair and reasonable long term price (including for the Company's own production) for purchase of DG, including NEG under the NM program.

Our household notes that while some Independent Power Producers (IPP) are forced to sell to FBC for as low as $17 per MWh, the Company is concurrently proposing to sell its own DG production to residential customers for $231 per MWh. The price for this electricity, which FBC has advised the Commission comes without any line loss, is 4.8 times more expensive than what the Company is prepared to pay its own DG and NM customers for their power. Such a proposal as it currently stands is contrary to section 59 of the *UCA*.

Of particular concern is the fact that, unlike usual commercial contracts, DG, including NM, enters the grid and is usually sold in the same Local Area Network or neighbourhood. It therefore comes onto the grid and is sold without incurring any line losses and without using FBC transmission lines before it is retailed back to a customer. We submit that the Commission panel in G-27-16 recognized this fact in its findings at 7.2 of the Order.

While it is acknowledged that individual solar PV and wind systems serve as intermittent resources, dependent on weather patterns for production, we note that the 2007 Energy Plan set out a directive, Action #25, for appropriate valuation of the aggregate of production of "intermittent resources", presumably across the entire service area of a utility.

Instead of focusing on the positive potential of the aggregate of production of DG/NM from all sources, including micro-hydro, the Company has, instead, tried to focus attention on the negative attributes of production from between 2 to 5 of their customers out of 233 now enrolled in the program.

In order to make a proper assessment of the potential of DG, and NM in particular, our household submits that the Commission should consider requiring FBC to produce the aggregate of production transferred from the sum total of NM enrollees and other non-enrolled DG customers, delineated by billing period and time of day, if necessary, before accepting any of the statements made by the Company concerning DG and NM to date.

I base my findings and assertions in my Final Argument on the experience of our household, and discussions and email correspondence with neighbours who are participants in the FBC NM program or who are off-grid DG producers, as well as discussions and email correspondence with Backwoods Solar Canada and a representative from BC Hydro, and on research into findings of previous Commission panels.

In contrast, the one time I tried to engage FBC in a discussion around their NM program, at the time they filed the Net Metering Program Tariff Update application, I was politely told that I had to do it through the BCUC hearing process. To date I am not aware of any survey done by FBC asking how they could improve the NM program, and I never receive any email updates about the program or see any updates about how it is developing on the FBC website.

After 30 years as a customer of this utility, our household expects better of both the Company and the BC Utilities Commission, because we believe, as innovators and early adopters, that reducing a household’s grid consumption by 1MWh per billing period is an achievement worth celebrating, not one to be dismissed and ignored.

All of which is respectfully submitted,
Andy Shadrack

Appendix A

Updated Electricity Consumption 2005-2017
Shadrack/Bauman Household

2005	**February**	**April**	**June**	**August**	**October**	**December**
Kwh Daily	1,194 19	1,182 19.1	1,094 18.9	828 13.1	1,048 18.7	1,074 17
Cost - Taxes	$93.73	$94.6	$89.05	$72.07	$85.9	$87.53
Cost +Taxes	$100.29	$101.22	$90.28	$73.86	$91.91	$93.66
2006	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	1,378 20	1,085 18.7	1,023 16.5	950 15.3	934 16.1	846 13.6
Cost - Taxes	$110.81	$93.42	$89.31	$84.44	$83.38	$77.52
Cost + Taxes	$117.91	$99.96	$95.96	$89.51	$88.38	$82.17
2007	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	1,063 17.1	829 13.4	681 11.5	678 10.9	572 9.4	662 11.2
Cost - Taxes	$92.63	$77.56	$68.74	$68.53	$61.24	$67.43
Cost + Taxes	$98.19	$82.21	$72.86	$72.64	$65.06	$71.75
2008	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	710 11.5	630 10.3	551 8.9	403 6.7 Fridge Broken	399 6.5 Fridge Broken	698
Cost - Taxes	$71.98	$67.11	$61.84	$51.45	$51.17	$72.50
Cost + Taxes	$75.87	$70.74	$65.18	$54.23	$53.93	$76.42
2009	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	604 10.1	678 10.9	581 10	580 8.1	430 7.4	687 11.1
Cost - Taxes	$70.67	$74.34	$67.10	$67.03	$56.64	$76.66
Cost +Taxes	$74.48	$78.36	$70.73	$70.65	$59.70	$80.80
2010	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	661 10.5	691 11.2	540 9.2	570 9.3	513 8.3	605 10.3
Cost - Taxes	$77.59	$81.59	$69.39	$71.80	$68.52	$76.79
Cost + Taxes	$81.78	$86.00	$73.13	$75.49	$71.94	$80.62

2011	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	596 9.6	584 9.6	487 7.9	622 10.4	413 6.9	638 10.3
Cost +Taxes	$79.37	$80.01	$72.90	$86.67	$67.40	$88.14
Cost - Taxes	$83.33	$84.01	$76.55	$91.00	$70.77	$92.55
2012	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	596 9.9	559 9	283 4.6 Away May	554 9.4	491 7.9	612 10
Cost - Taxes	$86.60	$84.12	$57.66	$77.91	$70.20	$80.19
Cost + Taxes	$90.93	$88.32	$60.54	$81.81	$73.71	$84.20
2013	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	576 9.1	587 9.5	480 9.4 Estimate	563 9.4 Estimate	459 7.9 Estimate	622 9.9 Estimate
Cost - Taxes	$79.88	$82.00	$72.58	$79.89	$70.74	$85.08
Cost + Taxes	$83.88	$86.10	$76.21	$83.88	$74.28	$89.33
2014	**February**	**April**	**June**	**August**	**October**	**December**
Kw/h Daily	665 10.4 Adjustment after strike	513 8.4	617 10	483 8.2	445 7.3	537 9.3
Cost - Taxes	$90.23	$76.98	$86.43	$74.25	$70.79	$79.16
Cost + Taxes	$94.74	$80.83	$90.75	$77.96	$74.33	$83.12
2015	**February**	**April**	**June**	**August**	**October**	**December**
Grid use Solar Transfer Net grid use Daily grid use Daily solar Total net use	673 - 673 10 - 10	398[1] - 398 9 .25 9.25	504[1] 285 219 2.8 1.5 4.3	351 341 10 .2 3.3 3.5	446 284 162 2.7 2.3 5	509 106 403 6.6 1.2 7.8
Cost - Taxes	$93.05	$59.7	$50.94	$31.28	$45.82	$68.86
Cost + Taxes	$97.70	$62.69	$53.49	$32.85	$48.11	$72.81

2016	February	April	June	August	October	December
Grid use	538	491	325	415	404	542
Solar Transfer	52	280	395	354	296	57
Net grid use	486	211	-(70)	61	108	485
Daily grid use	7.8	3.3	-(1.2)	1	1.7	7.7
Daily solar	.8	2.2	2.1	2.6	2.1	.8
Total net use	8.6	5.5	.9	3.6	3.8	8.5
Cost - Taxes	$77.85	$52	$24.43	$37.24	$41.86	$78.98
Cost + Taxes	$82.00	$55.98	$27.5	$40.84	$45.41	$83.21
2017	**February**	**April**	**June**	**August**	**October**	**December**
Grid use	538	364	445	363	373	213[3] (524[2])
Solar Transfer	89	102	334	713	517	81[3]
Net grid use	449	262	111	-(**350**)	-(**144**)	132[3]
Daily grid use	7.1	4.7	1.85	-(**5.7**)	-(**2.36**)	5.08[3]
Daily solar	.8	.7	N/A	3.1	3.1	1.19[3]
Total net use	7.9	5.4	N/A	(-**2.6**)	.7	6.27[3]
Cost - Taxes	$77.12	$58.60	$43.32	-($**3.32**)	$15.8	
Cost + Taxes	$80.98	$61.53	$45.48	-($**1.72**)	$17.4	

1. The April billing period ended early on the 2nd, the day we enrolled in the NM program and as a consequence the June billing period was longer.

2. Estimate only.

3. Based on 26 days data in the December 2017 billing period.

In 2014, the last year before our household installed a solar PV system, daily grid consumption of electrical power from FortisBC was 50.5% lower than 2005. By 2016, the first full year of solar production, average daily consumption had dropped to below 37% of 2005, and net daily consumption, after transfer of solar produced electrical power, was 19.9% of 2005.

Thus far in the first 301 billing days of 2017 we have purchased 2.083 MWh of electricity from FortisBC, while transferring 1.755 MWh to their grid. So our net consumption from FortisBC's grid is only .328 MWh or 1.09 kWh per day so far in 2017.

This consumption level represents a 93.6% reduction of grid electricity since 2006. To achieve that we have invested over $30,500 dollars in ten 300 watt panels and two 280, twelve batteries and the accompanying inverter equipment and installation costs.

Appendix B

MWh Needed To Offset Basic Charge And Customer Cost Per MWh Electrical Consumption				
Consumption Per Annum	Cost MWh Plus Basic Charge	MWh Needed to Offset Basic Charge	Cost Per MWh	Retail Value of Electricity to FBC
Net Zero @ 4.8 cents kWh @ FBC Basic Charge rate	$192.52	4.011	-	$555.56
Net Zero @ retail rate @ FBC Basic Charge rate	$192.52	1.724	-	$238.79
Net Zero @ BC Hydro Basic Charge Rate	$69.31	694	-	-
5 MWh	$698.39	-	$139.68	
10 MWh	$1,2226.23	-	$122.62	
15 MWh	$2,007.09	-	$133.81	
20 MWh	$2,787.94	-	$139.4	