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October 9, 2017

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Patrick Wruck, Commission Secretary

By email: commission.secretary@bcuc.com

Dear Sir:

Re: Site C Inquiry, Evidence of Mark Jaccard

I represent the B.C. Sustainable Energy Association. Attached for filing in the inquiry proceeding is expert evidence by Mark Jaccard titled "Evidence and Analysis of Two Issues Relevant to the Terms of Reference of the Site C Project Review." BCSEA's final submission will follow in due course.

Yours truly,

William J. Andrews

Barrister & Solicitor
cc. Fred James, BC Hydro Chief Regulatory Officer
Encl.

Final Report

Evidence and Analysis of Two Issues Relevant to the Terms of Reference of the Site C Project Review

October 7, 2017

Prepared for:
BC Sustainable Energy Association

Prepared by:
Mark Jaccard

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Introduction

In August 2017, the BC Sustainable Energy Association (BCSEA) asked me to advise it and possibly contribute evidence and analysis as part of its submission to the BCUC review of the Site C project. I responded that while I have been aware of the project for decades, and had looked in detail at its financial benefits and costs at the time I chaired the BCUC from 1992 to 1997, I was unaware of the most recent economic information and would be unable to review in detail all information from the review process.

I further noted that while I no longer believe that the province of British Columbia should be constructing new large hydropower projects, especially if involving significant flooding of valley bottoms, I was uncertain about whether the Site C project should be completed. I noted that because substantial money had already been spent on Site C, my views might change after seeing updated economic information. I also noted that as BC reduces its GHG emissions in accordance with Canadian and BC climate commitments, energy-economy modelling by several independent research teams, including the one I direct at Simon Fraser University, shows that the demand for zero-emission electricity should grow rapidly over the next three decades, which in BC could have repercussions for the long-run economic prospects of the Site C project, a matter of direct relevance to the Terms of Reference for the BCUC review of the Site C project.

With that understanding, I reviewed the 2017 Terms of Reference for the BCUC review of Site C, the 2014 Report of the Joint Review Panel on Site C, key sections of the BC Hydro 2013 Integrated Resource Plan (IRP), which provided the justification for the government's decision to build Site C, and criticisms of that IRP and the government's approval of Site C by various parties in recent years, including in this latest review process. This review led me to conclude that I could provide strategic evidence and analysis that would be a value to the BCUC in accordance with the Terms of Reference.

In this report, I provide that strategic evidence. It is strategic in that I do not conduct a comprehensive assessment of Site C and thus make no conclusions as to the current net value or cost of each of the three options: completion, delay or termination. Instead, I focus on two issues where I have expertise and where the evidence and argument advanced by some parties (be these BC Hydro, Site C opponents and supporters, or the BCUC itself) may be inconsistent with leading research about energy system economics and forecasting as it pertains to Site C-specific evidence.

The first issue involves the method used to estimate the value of electricity provided by Site C versus electricity provided by alternative renewable energy sources. Some opponents of the Site C project argue that the falling costs of electricity from solar and wind have eroded the economic rationale for Site C. However, the research literature shows that any assessment of value must recognize that dispatchable electricity from Site C is a different commodity than non-dispatchable electricity from solar and wind, with potentially a much higher market value depending on general and region-specific conditions. This means that the BCUC should not rely on unit electricity cost when comparing Site C with these other options. I explain this argument and offer suggestions for properly estimating the economic value of Site C versus its renewable competitors. This is a critical determination under the Terms of Reference of the Site C review.

The second issue involves BC Hydro's forecast of the demand for electricity from Site C, especially in the decade after the project's expected completion. Some opponents of the Site C project argue that much of its electricity production will be surplus to domestic need for years and perhaps decades after completion. They argue that because this surplus electricity is likely to earn a lower price when exported to Alberta or the US, the lumpy investment nature of Site C degrades its economic value relative to smaller renewable projects that can be developed at a pace that more closely tracks the growth of domestic demand.

This argument about the economic disadvantages of lumpy investments like Site C is valid in general. But its effect on the economics of Site C relative to smaller renewable competitors will depend on the growth rate of BC electricity demand, especially over the next two decades. Hindsight analysis shows that in recent years, BC Hydro forecasts have erred on the high side. The BCUC may conclude that BC Hydro's estimates are still biased upwards. However, certain policy shifts can provide surprises. One important possible surprise is the chance that governments nationally, provincially and municipally will intensify their GHG reduction efforts. If this occurs, the demand for electricity from near-zero-emission sources will increase dramatically. I show empirically what this higher electricity demand could mean in terms of BC Hydro's likely forecast error. Again, because the existence and duration of a surplus after the completion of Site C will play a significant role in determining its economic value, this issue is critical for fulfilling the Terms of Reference of the Site C review.

Finally, given the accelerated nature of the Site C review, and my personal experience with the situation in which the BCUC panel now finds itself, with volumes of information to process in a short period, I have deliberately followed the 'less is more' dictum in preparing this submission. I have devoted considerable time and effort to producing the most succinct submission possible given the strategic factors on which I focus.

Dispatchability and the relative value of Site C electricity

Section 3 (b) (iv) of the Terms of Reference of the Site C review asks the BCUC Panel to determine "what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits . . . to ratepayers at similar or lower unit energy cost as the Site C project".[1]

In their submissions and media communications, some intervenors in the Site C review argue that the declining unit energy costs of solar and wind have caused a relative decline in Site C's likely economic benefit since its approval in 2014. Further, they argue that this development is of direct relevance to the current review. For example, in his submission, Robert McCullough argues that "On a cost basis, hydroelectric greenfield generation can no longer compete favourably with renewable energy [since]…over the past decade, very importantly, the cost of renewables also fell – sharply"[2].

In considering this assertion, however, it is critical that the BCUC Panel be aware of the leading research on the economics of electricity supply alternatives. In this section of my submission, I review this research and its implications for the Site C review.

Unit cost is inappropriate for comparing individual electricity supply options, as this ignores differences in the market value of electricity at different times

Another term for the unit cost of energy is the levelized cost of energy, or, when assessing electricity supply options, the levelized cost of electricity.[3] While this concept may have been a useful indicator when electricity supply options provided almost identical system benefits (eg, for past comparisons of nuclear, coal and large hydro to provide baseload power), this is not the case when comparing non-dispatchable sources like solar and wind with a dispatchable source like Site C.

Dr. Paul Joskow of MIT is widely recognized as one of the world's leading energy economists, and I quote him at some length on this issue:

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[1] While I have published on the costs and benefits of demand-side management initiatives, and their comparison to or integration with supply options, I limit this submission to the comparison of renewable sources of electricity, especially solar and wind, with attributes of the Site C facility.

[2] McCullough, R. (2017). What We Have Learned About Site C. McCullough Research Submission to BCUC Inquiry Respecting Site C. Section IV Alternative Resource Costs, pg. 14. September 13, 2017. Accessed Oct. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90166_F35-5_Peace-Valley-Landowners-Association_Site-C-Submission.pdf

[3] Levelized cost is also sometimes called life-cycle cost. Unless stated otherwise, unit cost, levelized cost and life-cycle cost all refer to the ratio of the discounted stream of capital and operating costs over the lifetime of a project over the discounted stream of the project's output in MWhs or kWhs in each year. The key attribute, for my submission, is that the output is measured in MWhs or kWhs, without accounting for the different monetary value of this electricity at different times of day and year.

> The prevailing approach that relies on comparisons of the "levelized cost" per MWh supplied by different generating technologies, or any other measure of total life-cycle production costs per MWh supplied, is seriously flawed. It is flawed because it effectively treats all MWhs supplied as a homogeneous product governed by the law of one price. Specifically, traditional levelized cost comparisons fail to take account of the fact that the value (wholesale market price) of electricity supplied varies widely over the course of a typical year. The difference between the high and the low hourly prices over the course of a typical year, including capacity payments for generating capacity available to supply power during critical peak hours, can be up to four orders of magnitude.[4]

Joskow then uses a fictive example to emphasize his point:

> In a nutshell, electricity that can be supplied by a wind generator at a levelized cost of 6¢/KWh is not "cheap" if the output is available primarily at night when the market value of electricity is only 2.5¢/KWh. Similarly, a combustion turbine with a low expected capacity factor and a levelized cost of 25¢/KWh is not necessarily "expensive" if it can be called on reliably to supply electricity during all hours when the market price is greater than 25¢/KWh.[5]

Thus, Joskow is especially focusing on the inappropriateness of using unit energy cost for assessing the relative economic value of dispatchable and non-dispatchable (also called intermittent) electricity sources:

> Levelized cost comparisons are a misleading metric for comparing intermittent and dispatchable generating technologies because they fail to take into account differences in the production profiles of intermittent and dispatchable generating technologies and the associated large variations in the market value of the electricity they supply. Levelized cost comparisons overvalue intermittent generating technologies compared to dispatchable base load generating technologies.[6]

Joskow's view that it is inappropriate and misleading to compare dispatchable and non-dispatchable electricity sources by their unit energy costs now reflects the main-stream view of electricity system experts. This view has become prominent as researcher have focused on the economic implications of the rising share of solar and wind, especially in leading jurisdictions like Denmark, California, Texas and Germany.

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[4] Joskow, P. (2011). Comparing the Costs of Intermittent and Dispatchable Electricity Generation Technologies. Center for Energy and Environmental Research Working Paper 2010-013, revised February 2011. pg. 2. Accessed Oct. 2017 from: https://economics.mit.edu/files/6317. See also Joskow, P. (2011). Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies. American Economic Review 101(3): 238–41.

[5] Ibid pg. 3

[6] Ibid pg. 1

Research in this area requires the development and application of reliable models of a given electricity system that can simulate the cost-minimizing operation of the existing system and a cost-minimizing investment path as that system expands to meet growing demand. Such models need to be linked to models of other jurisdictions if the benefits of exchanging energy and capacity are to be included in the analysis. For assessing individual investments, the models can be used to compare two portfolios that provide the same services over time, with one including and one excluding that investment.

The terms of reference for the Site C review refer to "portfolios . . . of projects that provide similar benefits . . . to ratepayers at similar or lower unit energy cost as the Site C project." BC Hydro has for a long time been engaged in this type of portfolio analysis, as shown in its 2013 IRP and its recent update. However, BC Hydro has focused on unit energy cost calculations rather than undertaking new portfolio analysis for its submission on Site C to the BCUC review, and while the unit energy costs do have adjustments to partially reflect differences between dispatchable and non-dispatchable resources, BC Hydro notes that the benefits of dispatchable sources are not fully accounted for[7].

In the compressed timeframe of this review, it is not possible for the BCUC Panel to undertake a lengthy exercise with BC Hydro in which new portfolios are tested that explore alternative assumptions about the evolution of demand and the future costs of supply options. But researchers have studied the effects of rising wind and solar deployment, which has been especially rapid in countries and US states with mandated targets for renewables. In the next section, I summarize lessons from this research that has direct relevance to the question of whether the economic case for Site C is deteriorating because of the falling unit costs and growing role of wind and solar.

As non-dispatchable wind and solar increase in neighbouring jurisdictions, the market value of Site C's dispatchable capacity is likely to increase.

Electricity systems are complex. Demand and supply must be balanced in real-time in all locations. Demand fluctuates minute-to-minute, with peak loads occurring at different times in different locations. Generating units have traditionally been dispatchable. But their costs can differ significantly, with high capital cost / low operating cost units running much of the year to provide baseload (nuclear, coal, hydro) and low capital cost / high operating cost units operating at lower annual capacity factors, but always available to meet peak demand (natural gas). As non-dispatchable supplies increase, the total system effects can be difficult to estimate. This is why researchers build energy system optimization models, like the model BC Hydro uses, for assessing resource portfolios under different scenarios of supply and demand. Some of these are multi-jurisdictional

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[7] BC Hydro notes that "The dispatchable capacity benefits of Site C have not been monetized and are not reflected in the unit energy cost and present value benefit calculations and pumped storage has been treated in exactly the same manner in BC Hydro's analysis." BC Hydro (2017). Site C Inquiry – Round 2 Information Response. BCUC Inquiry Respecting Site C, F 1-6. October 3, 2017. Pg. 76. Accessed Oct. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/10/00295_F1-6_BcHydro_SiteC_Submissions.pdf

models to simulate interconnected systems, such as the US-REGEN model of the Electric Power Research Institute.

I avoid here a detailed analysis of the complexities that must be addressed within an electricity system optimization model, but there are many. Each portfolio must satisfy the same peak and energy reliability requirements in each sub-region, account for transmission constraints between sub-regions, incorporate the effect of DSM efforts that might differently affect energy and capacity demand in each sub-region, satisfy externality-based constraints such as GHG emission caps, prohibitions on certain technologies (eg. nuclear, coal, natural gas) and renewables mandates, and balance short-run supply and demand while also indicating an investment path that performs optimally under a range of plausible futures.

While there are many issues in electricity system portfolio analysis of relevance to the Site C review, I focus here on research that assesses the economic effect of a growing role for non-dispatchable wind and solar. Much of this research is conducted with the US-REGEN model, which is described in this quote from Bistline:

> The model solves an inter-temporal (cost-minimization) optimization problem in five-year time-steps to 2050, which combines a technologically detailed capacity planning model with optimized transmission investments and dispatch with intra-annual load segments based on representative hours. … In determining optimal resource mixes given scenario-specific assumptions, the dynamic version of US-REGEN optimizes generation across all model regions simultaneously for each representative intra-annual segment. … All versions of US-REGEN simulate endogenous trade decisions, and cross-border trade is restricted by net transfer capacities, which are endogenously represented in the dynamic model with possible transmission investments.[8]

US-REGEN can be used in the way that BC Hydro applies its optimization model to compare portfolios with and without Site C. US-REGEN can also be used to estimate the net benefit or cost of adding specific sources of electricity to an evolving electricity system comprised of interconnected jurisdictions.[9] This net benefit or cost of such additions is referred to as the "value factor", which indicates how the economic (market) value of an energy supply option changes with higher levels of market penetration. Bistline provides a definition of the value factor in the case of renewable generators:

> [The value factor] is the ratio of the average output-weighted revenue received by renewable generators in wholesale electricity markets for a given region (i.e., the average realized price received by participants in power markets) to the average hourly market-clearing price. This normalized value is linked to the financial

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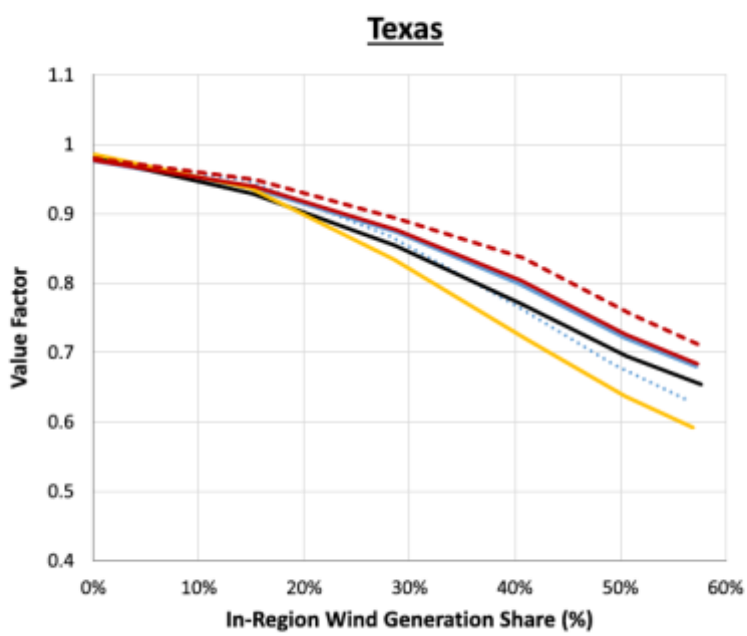
[8] Bistline, J. (2017). Economic and technical challenges of flexible operations under large-scale variable renewable deployment. *Energy Economics, 64*: 363-372. pg. 364.

[9] In my scan of the evidence, I have not noticed this type of use of the BC Hydro model, especially in application to all the jurisdictions near and far with which BC can exchange electricity.

value of resources in wholesale markets, not accounting for other potential revenues (e.g., participation in ancillary services markets or income from subsidies). The wholesale electricity price is based on the dual variable associated with the market-clearing (i.e., load balance) constraint. Normalizing revenues by regional load-weighted prices provides a way to compare values across different market settings and technologies.[10]

Figure 1 from a published paper by Bistline shows the value factor for increasing market penetration of wind power in Texas, simulated using US-REGEN. There are several lines to reflect different scenarios. The important point is that the value factor always declines with increased penetration of non-dispatchables such as wind. In this case, the average of the estimated values indicates that when wind reaches 55% of the electricity generated in Texas, its value factor falls by 30-40%. This occurs because an increasing proportion of wind generation is occurring at times of lower market value.

Figure 1 Value factor for increasing wind in Texas



Note: Figure from Bistline (2017)

Recall that the value factor is the ratio of the average output-weighted revenue received (i.e. average $ earned per unit of energy produced) by renewable generators to the average hourly market-clearing price. Also recall that by renewable generators, Bistline is especially referring to non-dispatchable wind and solar.

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[10] Bistline, J. (2017). Economic and technical challenges of flexible operations under large-scale variable renewable deployment. *Energy Economics, 64*: 363-372. pg. 365.

Thus, the falling value factor means that as these *non-dispatchable* renewables comprise a larger share of the electricity produced in a region, the returns to *dispatchable* sources per unit produced are rising in relative (and perhaps absolute) terms. Mathematically, this must be, since the average hourly market-clearing price is the average of returns earned by non-dispatchable and dispatchable generators – which comprise all suppliers.[11]

This analysis supports Joskow's point that unit energy cost is a misleading indicator because it suggests that all electricity generators provide the same product when in fact dispatchable generation can provide a different, more valuable product, that being reliable electricity at times when it is most valuable to the system. The analysis goes further, though, in suggesting that there is a negative correlation between the penetration of non-dispatchable sources and the average value earned per unit of their production.

Furthermore, the higher revenue earned for energy supplied during times of peak demand may still not be capturing the full value of dispatchable generators. According to Joskow, the revenues offered in existing energy-only wholesale electricity markets may not provide sufficient incentive to build generating plants that may sit idle for long periods of time but are available to meet peak demand and thereby satisfy consumer preferences for reliability[12]. Various market mechanisms could help to alleviate this problem, such as establishing capacity payments, which involve paying generators for the capacity they guarantee at critical times, even if the grid operator ultimately does not require it[13]. The need for market mechanisms that provide compensation for the full value of dispatchable generation will become increasingly important as more intermittent renewable energy is added to the grid[14].

Note that this discussion is in no way suggesting that Site C will largely sit idle and only provide energy at peak times. Rather, it is further emphasizing that an economic evaluation of Site C should account for the full value of its dispatchable capacity. Since current wholesale spot prices in most cases do not capture the full value of dispatchable capacity, these should not be used as an indicator of the future value of dispatchable capacity from a generator like Site C. As the penetration of intermittent renewables increases, it will become increasingly important for markets to incentivize dispatchable

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[11] Blanford (2015) shows that the marginal value factors for wind and solar decline faster than the average value factors (which is mathematically obvious), but the declining average values are sufficient to make my point. Blanford, G. (2015). Decreasing returns to renewable energy. Program 178b. Technical Report 3002003946. Electric Power Research Institute. Accessed Oct. 2017 from: https://www.epri.com/#/pages/product/000000003002003946/

[12] Joskow, P. (2008). Capacity payments in imperfect electricity markets: Need and design. *Utility Policy, 16*: 159-170.

[13] Levin, T. & Botterud, A. (2015). Electricity market design for generator revenue sufficiency with increased variable generation. *Energy Policy, 87*: 392-406.

[14] Jenkin, T., Beiter, P. & Margolis, R. (2016). Capacity Payments in Restructured Markets under Low and High Penetration of Renewable Energy. National Renewable Energy Laboratory Technical Report, NREL/TP-6A20-65491. Accessed Oct. 2017 from: https://www.nrel.gov/docs/fy16osti/65491.pdf

capacity for its full value, and thus the revenue earned for dispatchable capacity will exceed current spot prices, perhaps substantially.

In the case of Site C, there may be conditions that limit that project's ability to capture value (additional revenues) from its dispatchability attribute[15]. As one example, the BC electricity system is currently dominated by dispatchable large hydro facilities, so the within-province incremental benefit of adding Site C may be limited. This possible concern, however, would likely be moderated by the fact that value can also be captured through sales to neighbouring jurisdictions.

In summary, the main point, in terms of the Site C review Terms of Reference, is that the BCUC Panel must take into account the differences in value provided by non-dispatchable and dispatchable generators when evaluating the claim that falling costs of non-dispatchable renewables erode the relative economic position of Site C. It may well turn out that the effect is the opposite.

Forecasting BC electricity demand under GHG policy

While Section 3 (b) of the Terms of Reference of the Site C review tells the BCUC Panel that it "must use" BC Hydro's 2016 demand forecast, clause 3 (b) (ii) tells it that it must require BC Hydro to report on "other factors that could reasonably be expected to influence demand from the expected case toward the high load or the low load case." In this section, I focus my analysis on a factor that could cause electricity demand in BC in the period 2020 to 2050 to grow much more rapidly than anticipated in BC Hydro's forecast. This factor is an intensified effort by governments at all levels in Canada, and internationally, to reduce energy-related GHG emissions. While I do not have the resources and time to redo BC Hydro's forecast when focusing on this factor, I and associates have done modelling studies of GHG targets of Canada, BC and major BC cities to assess their potential incremental implications for BC Hydro electricity demand. In this section, I control for differences in forecast assumptions in order to estimate what the incremental electricity demand would be relative to BC Hydro's 2016 demand

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[15] Note that Site C is a fully dispatchable source. The BCUC Panel will hopefully not be misled by the argument of R. McCullough that it is somehow a detriment that the Site C dam's reservoir would not be large. In his submission to the BCUC, McCullough claims that 'The argument that Site-C can serve as storage for future alternative sources of energy is highly questionable given its lack of reservoir capacity.' (McCullough, R. (2017). What We Have Learned About Site C. McCullough Research Submission to BCUC Inquiry Respecting Site C. Section V Storage and Dispatchability, pg. 24. September 13, 2017. Accessed Oct. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90166_F35-5_Peace-Valley-Landowners-Association_Site-C-Submission.pdf .) This is a red herring when it comes to valuing Site C's dispatchability. The facility does not need storage to be fully dispatchable. It simply needs to receive a reliable flow of water sufficient to run at full capacity when most needed. This it can do, in part because of the water flow regulation from the upstream Bennett Dam. In the same vein, a natural gas peaking plant does not need on-site storage of compressed or liquefied natural gas. It simply needs to receive a reliable flow of natural gas sufficient to run at full capacity when most needed. In this case, that flow of natural gas is provided by connection to a pipeline.

forecast of successful efforts to reduce GHG emissions. I focus especially on the period 2025 to 2035, the decade after Site C's completion. Demand in this decade could be critical for assessing the likely economic benefit of Site in this review process.

Challenges in forecasting demand for BC Hydro's electricity

The domestic demand for BC Hydro's electricity in the years 2025 to 2035 and beyond is critical to the economics of the Site C project. If the project is mostly surplus to domestic need in the decade or so after completion, its exported electricity will garner a lower price and the project's upward effect on rates will be greater, all things being equal, relative to smaller renewable energy alternatives that can be brought online at a pace that more closely matches demand growth.

The BC government and the BCUC Panel are therefore concerned with the reliability of BC Hydro's forecasting methodology. While evidence suggests that BC Hydro has erred to the high side in its demand forecast covering the last decade, the BCUC Panel argues, in its interim report, that BC Hydro's forecasts should not have a systematic bias. "The Panel views an effective forecast as one that produces results reasonably close to actual with equal instances of over and under forecasts." It goes on to say that "a load forecast model should be designed to be as accurate as possible in order to better inform a decision related to the trade-offs of erring on one side or the other."[16]

The BCUC Panel notes, moreover, that "the most significant issue with BC Hydro's historical forecasting accuracy relates to the industrial sector forecasts." And it points out that "This issue is of particular importance because BC Hydro's Current Load Forecast predicts significant growth in industrial load between now and 2036."[17]

Given the complexity of factors determining electricity demand, it will always be possible in hindsight to show error. And because industrial electricity demand, especially from large industrial plants, can be particularly uncertain, load forecasts will have greater uncertainty in this sector of the economy. However, it is important to note that the nature of electricity demand growth throughout industrialized countries is changing in that heavy industry demand is shrinking while commercial and residential demand grows in relative importance. And this trend can accelerate with the greater importance of footloose commercial activities, such as online servers, that gravitate disproportionately to jurisdictions with relatively low electricity rates, such as BC. Thus, even if it turns out that BC Hydro's forecast continues to overestimate industrial demand to some degree, continued growth in other sectors will significantly increase electricity demand.

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[16] BCUC (2017). British Columbia Utilities Commission Inquiry Respecting Site C: Preliminary Report to the Government of British Columbia. Executive summary, pg. iv. Sept. 20, 2017. Accessed Sept. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90185_A-13_Preliminary-Report-2.pdf

[17] Ibid. Section 5.1.4.2, pg 59-60.

BC Hydro in its submission[18], Deloitte in its report to the BCUC[19], and the BCUC Panel in its interim report comment on other possible disruptive causes of error in the load forecast. Deloitte and the BCUC both note that decentralized electricity generation – from urban combined heat and power, industrial cogeneration, and customer-owned rooftop photovoltaic panels – could reduce the share of BC's electricity consumption that is supplied from BC Hydro facilities. It is noteworthy, however, that BC's low electricity rates and climate hinder the wide-scale development of rooftop PV, while urban and industrial combined heat and power are only competitive if low cost natural gas is the energy source, a development that will be hindered by climate policies, including BC's clean electricity policy and the renewables targets of Vancouver and Victoria.

In that regard, the BCUC Panel and Deloitte acknowledge that climate policies will increase the use of near-zero-emission electricity (such as that produced by BC Hydro) in industry, buildings and transport. But they acknowledge that the amount of this increase and its timing is uncertain. As this is my area of expertise, I focus on this uncertainty.

In the rest of this section, I estimate what current GHG commitments may imply for electricity use and compare my estimates to BC Hydro's assumptions about the incremental effect of GHG-related electrification. By focusing on this single issue, I hope to help the BCUC in its assessment of the likelihood of upward or downward bias in the BC Hydro forecast, which is essential for its assessment of Site C's economic value. But because I focus only on this one incremental source of forecast uncertainty, I am not able to comment on the overall likelihood of BC Hydro's forecast being biased upwards or downwards. The BCUC Panel can only make that assessment after considering evidence on all the potential causes of forecast error.[20]

GHG targets and their incremental implications for BC Hydro demand

The Canadian government led by Prime Minister Justin Trudeau has committed to reduce GHG emissions 30% by 2030 and 80% by 2050[21]. In 2007, the BC government led by

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[18] BC Hydro (2017). BC Hydro Submission to British Columbia Utilities Commission: Inquiry into the Site C Clean Energy Project. Aug. 30, 2017. Accessed Sept. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90101_F1-1-BCH_submission_SiteC_Public.pdf

[19] Deloitte LLP (2017). British Columbia Utilities Commission: Site C – Alternative Resource Options and Load Forecast Assessment. Sept. 8, 2017. Accessed Sept. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90150_A-9_Site-C-Inquiry_Deloitte-LLP-Independent-Report-No2.pdf

[20] One of these is the effectiveness of BC Hydro's DSM efforts to increase electricity efficiency. In other research, I and others have found that utilities tend to overestimate the ability of their DSM efforts to reduce electricity demand. See Rivers, N. & Jaccard, M (2011). Electric Utility Demand Side Management in Canada. *The Energy Journal, 32 (4)*: 93-116. http://www.jstor.org/stable/41323335

[21] Government of Canada (2016). Pan-Canadian Framework on Clean Growth and Climate Change. Accessed Sept. 2017 from: https://www.canada.ca/content/dam/themes/environment/documents/weather1/20170113-1-en.pdf; Government of Canada (2016). Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy. Accessed Sept. 2017 from: http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf

Premier Gordon Campbell set a 2020 GHG reduction commitment, but that target will not be met. Premier Christy Clark's government abandoned Campbell's 2020 target and instead focused only on a longer-term target in its 2016 Climate Leadership Plan of 80% reduction by 2050[22]. Finally, the City of Vancouver has a 2050 target for 80% GHG reduction and 100% energy from renewables[23].

For three decades, the research group I lead in the School of Resource and Environmental Management at Simon Fraser University has developed and applied energy-economy models that estimate the effect of climate policies by single or multiple levels of government. These models are noted for being technologically explicit and behaviourally realistic, meaning that they simulate how individuals and companies choose technologies, fuels, levels of energy efficiency and even lifestyles (commuting distance, transport mode, size and type of residential building) that influence energy use and GHG emissions. (Although energy is critical in determining GHG emissions, the models are used in conjunction with ancillary models or analysis of non-energy GHG sources, such as landfill emissions, land-use change and various industrial processes.)

In recent years, we, or researchers and consultants using our models, have conducted several studies of GHG climate policies to achieve Canada's, BC's and, in one case, Vancouver's GHG reduction targets. The following studies are especially pertinent to the Site C review.

In 2012, my consulting company, M.K. Jaccard and Associates (MKJA), used underlying GDP, population and industrial activity forecast assumptions from BC Hydro to estimate the incremental effect of a successful pursuit of GHG reduction targets on BC Hydro's electricity demand[24] (referred to hereafter as MKJA 2012). In this exercise, policy-induced emission reductions (mostly from carbon pricing) fell short of achieving current government targets for BC, with a 24% GHG reduction by 2030 and a 54% reduction by 2050 (the scenario with moderate natural gas prices). The resulting additional electricity demand above the Reference scenario, which has no policy to reduce GHG emissions, was 13 TWh in 2030 and 28 TWh in 2050. The study examined the sensitivity of the results to different natural gas prices, since lower natural gas prices may lead to less switching to electricity while higher natural gas prices may lead to more. In 2030, the low natural gas price scenario achieved a 22% emission reduction and required 9 TWh of electricity above the reference scenario, while the high natural gas price scenario achieved a 27% emission reduction and required 19 TWh of electricity above the reference scenario.

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[22] Government of British Columbia (2016). Climate Leadership Plan. August 2016. Accessed Sept. 2017 from: https://climate.gov.bc.ca/app/uploads/sites/13/2016/10/4030_CLP_Booklet_web.pdf

[23] City of Vancouver (2015). Renewable City Strategy. November 2015. Accessed Sept. 2017 from: http://vancouver.ca/files/cov/renewable-city-strategy-2015.pdf

[24] MKJA (2012). BC Hydro Electrification Potential Review Final Report. May 8, 2012. In: BC Hydro 2013 Integrated Resource Plan, Appendix 6C. Accessed Sept. 2017 from: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf

In 2016, I and two research associates produced a report which estimated alternative policies to achieve Canada's 2030 target (30%), with emissions continuing to decline thereafter to reach 45 to 55% reductions by 2050[25] (referred to hereafter as Jaccard et al. 2016). Because our model is nationally differentiated, we also estimated the economically efficient allocation of the national target among Canada's provinces and territories. Our simulations thus show reductions in BC's GHG emissions of 23 to 29% by 2030 and 38 to 53% by 2050. Achieving this GHG reduction would require approximately 8 to 12 TWh of electricity in BC above what would otherwise be required with minimal GHG policy effort. Emission reductions and electricity requirements are shown as a range due to differing assumptions about future global oil prices.

In 2017, I and two research associates produced a report which estimated the effect of Vancouver's target of 100% renewables by 2050, especially focused on buildings and intra-urban transport of goods and people[26]. Since near-zero-emission electricity is an ideal option for reducing use of the key sources of urban GHG emissions, that being gasoline and natural gas consumption, the analysis showed that achieving the 100% renewables objective would see an increase in electricity use by approximately 70% in the 2020 to 2050 timeframe in Vancouver. Victoria has since adopted a target similar to Vancouver's, and other BC municipalities are considering establishing targets.

Finally, in 2017, I and a research associate produced a report which estimated the effect of a national climate policy focused on reducing GHG emissions in transportation[27] (referred to hereafter as Vass & Jaccard 2017). The study achieved economy-wide national emission reduction objectives of 30% in 2030 and 65% in 2050, the latter being the target of the previous government of Prime Minister Stephen Harper. BC's efficient allocation of emission reductions was 25% by 2030 and 64% by 2050. While we found that biofuel consumption is likely to play a significant role in decarbonizing transportation, we also found a considerable increase in electricity demand, especially for intra-urban transport of people and goods. With strong policy, plug-in electric vehicles accounted for 13% of personal vehicles on the road by 2030, and close to 60% by 2050. Uptake of electric urban delivery trucks was slower in the short term – 1% market share by 2030, but achieved nearly 50% market share by 2050. The resulting electricity

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[25] Jaccard, M., Hein, M. & Vass, T. (2016). Is Win-Win Possible? Can Canada's Government Achieve Its Paris Commitment…and Get Re-Elected? Sept. 20, 2016. Simon Fraser University, Energy and Materials Research Group. Accessed Sept. 2017 from: http://rem-main.rem.sfu.ca/papers/jaccard/Jaccard-Hein-Vass%20CdnClimatePol%20EMRG-REM-SFU%20Sep%2020%202016.pdf

[26] Zuehlke, B., Jaccard, M. & Murphy, R. (2017). Can Cities Really Make a Difference? Case Study of Vancouver's Renewable City Strategy. Mar. 14, 2017. Simon Fraser University, Energy and Materials Research Group. Accessed Sept. 2017 from: http://rem-main.rem.sfu.ca/papers/jaccard/ZuehlkeJaccardMurphy-Vancouver_Renewables_Report-March%202017

[27] Vass, T. & Jaccard, M. (2017). Driving Decarbonization: Pathways and Policies for Canadian Transport. Jun. 29, 2017. Simon Fraser University, Energy and Materials Research Group. Accessed Sept. 2017 from: http://rem-main.rem.sfu.ca/papers/jaccard/Vass-Jaccard%20Biofuel-CFS%20in%20Canada%20Transport%20June%2029%202017.pdf?_ga=2.21968763.1798153659.1498825214-2021187452.1495712198

required for these electric vehicles and trucks in BC would be approximately 1.5 TWh in 2030 and 12 TWh in 2050. Note that uptake of EVs by 2030 in this study errs on the conservative side compared to our other studies.

Unlike the studies outlined above, BC Hydro's electricity forecasts to date implicitly assume that Canada and BC will fall far short of achieving their 2030 and 2050 GHG reduction targets. While the BC Hydro submission to the BCUC acknowledges that substantial greenhouse gas emission reductions will likely increase electricity demand, it notes that 'BC Hydro has not revised the Current Load Forecast upward to account for electrification initiatives directed at reducing greenhouse gas emissions'[28]. The BC Hydro load forecast does include some increased demand for electricity from increased sales of personal electric vehicles, but the market share of electric vehicles in its load forecast – 8.1% of total market share in 2030 – is considerably lower than the market share that our modelling suggests would be likely with strong GHG policy – between 13 and 34% in 2030[29]. Also, BC Hydro's forecast does not appear to account for the potential for GHG policy-driven electrification of other forms of transportation, such as buses and urban delivery trucks, nor does it provide a comprehensive quantification of the likely impact of GHG policy on electrification in sectors outside of transportation.

To situate BC Hydro's forecasts among forecasts with minimal to strong GHG reduction policy efforts, Figure 2 compares two recent BC Hydro load forecasts with load trajectories from two scenarios of the aforementioned 2012 MKJA study completed for BC Hydro. The BC Hydro forecasts shown are the mid-range forecasts for the integrated system total gross requirement, excluding demand expected from LNG development and before expected demand-side management (DSM) savings[30]. The 2012 load forecast was used for BC Hydro's 2013 Integrated Resource Plan[31]. In 2016, BC Hydro updated its load forecast for its 2017-2019 Revenue Requirements Application[32]. This is the same

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28 BC Hydro (2017). BC Hydro Submission to British Columbia Utilities Commission: Inquiry into the Site C Clean Energy Project. Section 5.2.2.4, pg. 53. Aug. 30, 2017. Accessed Sept. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90101_F1-1-BCH_submission_SiteC_Public.pdf

29 The range of estimates results from different assumptions regarding factors such as the relative prices of fuels including electricity and biofuels, the costs of electric vehicles, and consumer preferences.

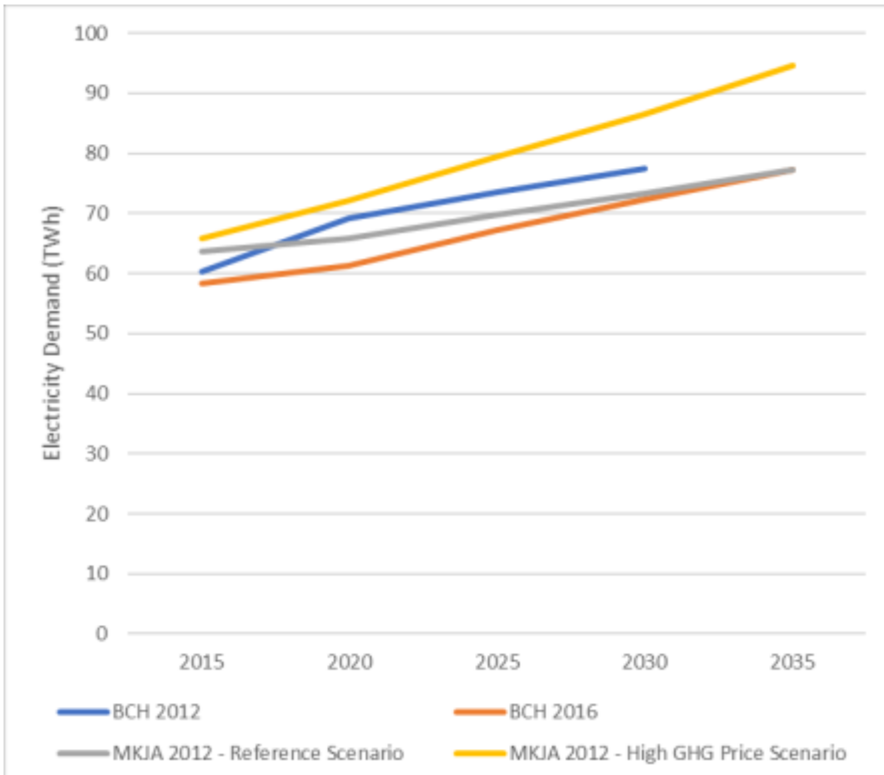
30 BC Hydro's DSM efforts include information programs, rate design, and advocating for government efficiency regulations. These expected savings are often challenging to achieve – as noted above, our research suggests that utilities often overestimate how much savings can be achieved by DSM. Since DSM savings may very well turn out to be negligible, we show the pre-DSM forecast. Note that while our modelling studies include little demand reduction from DSM efforts like subsidies and information, they do include energy efficiency and conservation (demand reduction) driven by forecast energy price increases and by climate policies to regulate efficiency or levy rising charges on GHG-emitting energy.

31 BC Hydro (2013). Integrated Resource Plan. Chapter 2: Load-Resource Balance; Appendix 2A: 2012 Electric Load Forecast. Accessed Sept. 2017 from: https://www.bchydro.com/about/planning-for-our-future/irp/current-plan/document-centre/reports/november-2013-irp.html

32 BC Hydro (2016). Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 3: Load and Revenue Forecast. Accessed Sept. 2017 from: https://www.bchydro.com/content/dam/BCHydro/customer-

load forecast that BC Hydro used in its 2017 submission to BCUC on Site C[33]. BC Hydro notes that market changes in the large industrial sector, including closure of a major pulp mill and reduced expectations for load growth until commodity prices recover, as the main reason for somewhat lower demand in its 2016 forecast as compared to the 2012 forecast.

Figure 2 Load forecasts from BC Hydro and MKJA 2012 study



The 2012 MKJA study aimed to align its underlying assumptions (such as GDP growth, population growth, and energy prices) with those being used for BC Hydro's 2013 IRP. It excluded potential natural gas loads coming from production in the Horn River Basin or from LNG terminals in the Kitimat area, and thus is aligned in terms of LNG assumptions with the BC Hydro forecasts we show prior to expected LNG loads. The MKJA Reference scenario assumes minimal new policy efforts to reduce GHG emissions, while as noted above the High GHG Price scenario achieves a 24% BC reduction by 2030 and 54% by 2050. It should be noted that while the amount of GHG reductions in the High GHG Price scenario falls within the range that would likely be efficient for BC if Canada

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portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf

[33] BC Hydro (2017). BC Hydro Submission to British Columbia Utilities Commission: Inquiry into the Site C Clean Energy Project. Appendix K: Portfolio Analysis Assumptions and Load Resource Balances. Aug. 30, 2017. Accessed Sept. 2017 from: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90101_F1-1-BCH_submission_SiteC_Public.pdf

were to achieve its national 2030 GHG reduction commitment, this scenario still fails to achieve the GHG reduction commitments of BC and Canadian governments over the 2030 to 2050 timeframe. A scenario that achieved the 2050 GHG commitments would have an even greater increase in electricity consumption.

The BC Hydro's load forecasts – even the 2012 forecast that includes some LNG development – are much closer to the MKJA Reference scenario than to the High GHG Price scenario. Since the MKJA study aligned inputs with BC Hydro's, this supports the conclusion that the BC Hydro forecasts are likely accounting for little, if any, of the electrification that would occur from policy efforts to achieve substantial GHG emission reductions. This is as expected given that neither the 2012 forecast nor the 2016 forecast update stated that these forecasts assumed achievement of GHG reduction objectives.

BC Hydro's Site C Submission to the BCUC notes that it plans to look at the impacts of electrification in more detail for the 2018 Integrated Resource Plan. In the absence of that information for the current Site C Review, my analysis here aims to provide an approximate quantification of the likely increased electricity demand from a strong policy effort to reduce GHG emissions, albeit one that does not fully achieve the 2050 GHG commitments of governments at the municipal, provincial and federal levels.

The 2012 MKJA study and our more recent studies noted above show a considerable increase in demand for electricity in scenarios with substantial policy efforts to reduce GHG emissions, as compared to scenarios with minimal policy efforts. Figure 3 summarizes the incremental electricity demand with substantial GHG reductions in three of our studies. The incremental electricity demand is calculated as the difference in electricity demand between a given study's strong GHG policy scenario[34] and that same study's reference scenario[35]. The electricity demand estimates are adjusted to be comparable to BC Hydro's total gross requirement estimates, which include only the BC Hydro service area and include line losses[36].

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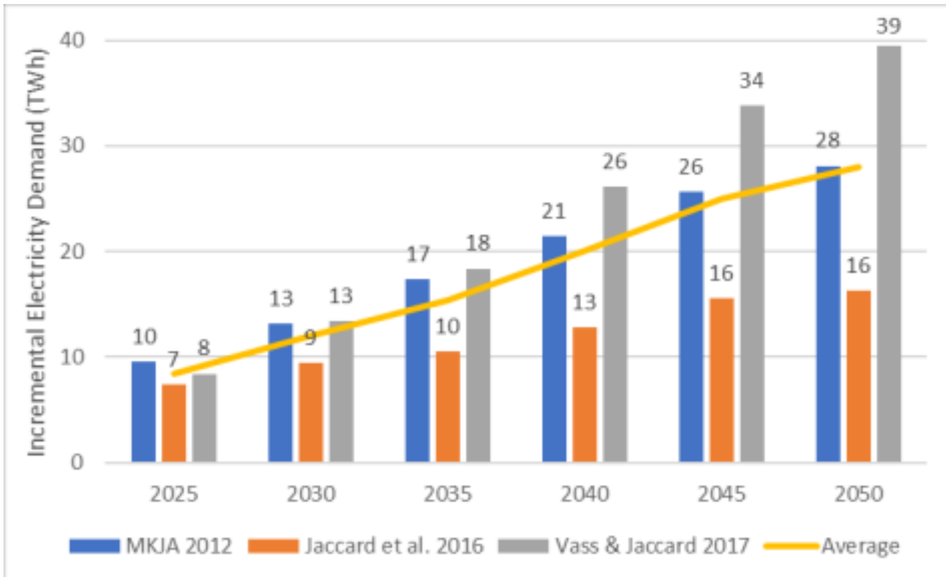
[34] For all three studies, the scenario I use achieves substantial GHG reductions as a result of a rapidly rising emissions price. However, the same GHG reductions could be achieved by any combination or separate application of emissions pricing or regulations.

[35] For MJKA (2012), I use the medium natural gas price scenario. For Jaccard et al. (2016), I take the average of the low and high global oil price scenarios. For Vass & Jaccard (2017), the Reference Scenario includes recently announced modest GHG reduction efforts from the Pan-Canadian Framework on Climate Change. Therefore, I adjust electricity demand in the Reference Scenario to remove increases in electricity demand as a result of those policy efforts.

[36] The MJKA 2012 study was designed to be comparable to BC Hydro's electricity demand estimates. For Jaccard et al. (2016) and Vass & Jaccard (2017), two adjustments were made: A) Our initial electricity demand estimates from CIMS cover 100% of provincial demand net of industrial cogeneration, whereas in 2015 the BC Hydro service area covered approximately 85% of provincial demand (based on data from StatsCanada and BC Hydro, after adjusting for industrial cogeneration). Thus I multiply our estimates by 0.85. B) Our initial electricity demand estimates are net of line losses, whereas BC Hydro gross requirements include lines losses averaging 9.4% of sales per year (average from 2012 to 2016 BC Hydro annual reports). Thus I multiply our estimates by 1.094.

Figure 3 Incremental Electricity Demand with Substantial Policy-Driven GHG Reductions, as Compared to Minimal GHG Reduction Policy



In any modelling study, various assumptions must be made about the future, including trajectories for population, GDP, energy prices, and technology costs. These assumptions impact scenario results, including GHG emissions and demand for different forms of energy. The three studies I compare were completed at different times and for different purposes, and thus have some differences in their assumptions[37]. Some of these assumptions presumably differ to some degree from those that BC Hydro uses in its modelling. If I were to directly compare our strong GHG policy scenarios to BC Hydro's estimates, we would not know for sure if the differences were driven by GHG reductions alone or also due to differences in other assumptions. To help control for these other differences, I have chosen to focus here on incremental demand between the strong policy and minimal policy scenario within each study.

Since BC Hydro's forecasts assume minimal GHG reduction policies, one could broadly assume that if strong policies were adopted, the incremental demand estimates with GHG reductions would also be approximately incremental to BC Hydro's forecasts. As Figure 3 shows, this incremental demand is considerable across all three of our studies, despite its precise magnitude varying to some degree based on the different underlying assumptions and the differing extent of emission reductions achieved in each study. On average among the three studies, incremental electricity demand with strong GHG reduction policy was found to be 8 TWh in 2025, 12 TWh in 2030, 15 TWh in 2035, and 28 TWh in 2050.

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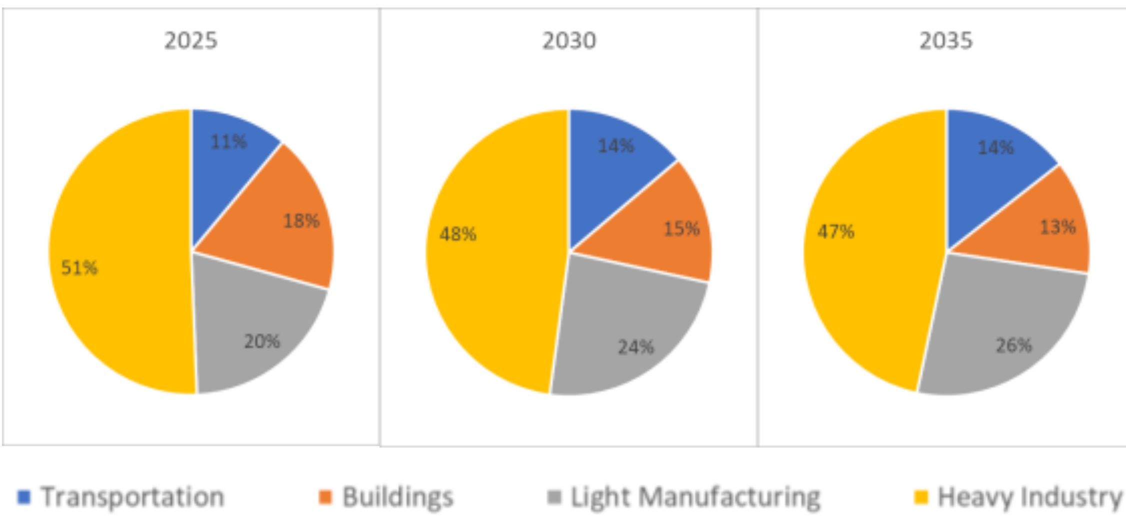
[37] As just one example, whereas the MKJA (2012) study assumed minimal LNG development, the Jaccard et al. (2016) and Vass & Jaccard (2017) studies used a 2016 National Energy Board natural gas development trajectory, which assumes some degree of LNG development.

Figure 4 shows the percent breakdown of the incremental electricity demand by sector, as an average of our three studies. Approximately half of incremental demand comes from heavy industry[38]. Electrification of heavy industry would involve moving to processes powered by electricity rather than by fossil fuels, such as drying coal with heaters powered by electricity rather than natural gas, or extracting natural gas with technologies powered by electricity rather than natural gas. As noted above, future demand for electricity is likely most uncertain for heavy industry. It could be possible that our studies overestimate future growth in electricity demand from heavy industry, and that reduced growth in demand from some industrial customers could largely counteract increases in demand from other industrial customers due to electrification. However, even if this were the case, since half of the incremental demand growth comes from other sectors – i.e. transportation, buildings, and light manufacturing – there would still be substantial increases in electricity demand if strong GHG reduction policies were adopted.

Figure 4 Average Percent of Incremental Electricity Demand with Substantial Policy-Driven GHG Reductions by Sector



In summary, my analysis shows that achieving GHG emission reductions would substantially increase demand for electricity. As already noted, however, I do not comment on the overall accuracy of BC Hydro's forecast, and thus my analysis does not say if I think the its forecast is biased upwards or downwards in aggregate. My analysis simply shows, all things being equal, by how much it could be biased downwards if governments achieve their GHG reduction commitments. For several reasons, notably related to intensifying climate impacts, this is a trajectory that cannot be easily dismissed.

[38] Heavy industry load includes chemical manufacturing, industrial mineral processing, metal smelting, mineral mining, paper and pulp manufacturing, petroleum refining, petroleum crude extraction, natural gas extraction, and coal mining. Some of our sectoral divisions may not precisely match the customer classes BC Hydro uses for its load forecasting.