Site C: Complete, Mothball, or Abandon?

Submission to the BC Utilities Commission Inquiry on

Site C

Harry Swain

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Framework for analysis

[1] Former chair of the Joint Review Panel on Site C in 2013-14. Long ago I was the federal director-general for electricity, coal, uranium and nuclear energy. Later, as deputy minister of Indian Affairs and Northern Development Canada, I was responsible for electricity service to two territories and 600 reserve communities. The analysis and opinions in this submission are entirely mine.

The basic logic of cost-benefit analysis is that the benefits of the project in question should be sufficiently greater than its costs, including social, environmental and First Nations costs, as to allow those who profit to compensate those who lose, and leave a net benefit for society at large. In the present case, the relevant financial costs are those required to complete a project in progress. Expenditures to date and irrevocably committed must be repaid—part of the rates issue—but do not bear on the decision to proceed, mothball, or terminate. They are irrevocably sunk. As to benefits, in a financial analysis they are adequately approximated by the present value of the stream of expected revenues, discounted at an appropriate rate. The load forecast, the basis for revenues, is thus critical.

Project costs

(Terms of Reference: 3(b)(i))

The public must rely on the Commission to extract the cost of the project from BC Hydro. Nothing published so far allows a close estimate of what has been spent, how much under current contracts is irrevocable, and how much remains, although reasonable estimates were made by the UBC team under Prof. Karen Bakker last spring.[2] The annual financial statements, published a surprising 5½ months after the end of the fiscal year, record $4 billion as spent or contractually committed as of March 31, 2017,[3] but say nothing about the costs under early termination scenarios.

In addition to simply acquiring BC Hydro's data, the Commission will need to examine past expenditures for correct attribution, and examine the break clauses in current contracts. Merely summing the currently forecast

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[2] R. Hendriks, P. Raphals and K. Bakker, "Reassessing the need for Site C," Program on Water Governance, University of British Columbia, 2017, pp. 13-27. I understand this paper is being made available to the Commission as part of the record of the Inquiry.

[3] British Columbia Hydro and Power Authority, *2016/17 Annual Service Plan Report*, August 2017, p. 15

expenditures under these contracts would be inadequate. All competent large construction contracts contain clauses specifying damages if unforeseen circumstances lead to early termination.

Likewise, the Commission is the only party well placed to estimate the costs to completion, which are also unknown to outsiders. The fact that the $7.9 billion estimate at the time of the JRP hearings was attested to as wholesome by KPMG, a company which as BC Hydro's auditor may be thought to have a conflict of interest, and then were promptly increased to $8.8 billion, gives pause. The recent discovery of unexpected geotechnical conditions at the dam site, as well as instability in the consortium executing the project, may lead this estimate to be exceeded. BC Hydro's experience is directionally consistent with the cost escalations that have plagued Keeyask (Manitoba), Muskrat Falls (Labrador), and many other large hydro projects. A comprehensive economic analysis by Oxford University researchers of 245 large dams around the world found the average cost overrun was 96 percent, with the larger projects having the highest overruns.[4]

There are other unquantifiable project costs which are not part of the Commission's remit nor this analysis.[5]

Project benefits

(Terms of Reference: 3(c))

[4] Atif Ansar, Bent Flyvbjerg, Alexander Budzier and Daniel Lunn, "Should we build more large dams? The actual costs of hydropower megaproject development," *Energy Policy* [2014], http://dx.doi.org/10.1016/j.enpol.2013.10.069

[5] Principal among these are the social and environmental costs detailed in the *JRP Report,* and the question of First Nations' s. 35 rights, including the possible applicability of the tests in *R. v. Sparrow*, [1990] 1 S.C.R. 1075. *Report of the Joint Review Panel—Site C Clean Energy Project* (henceforth the *JRP Report*), Canadian Environmental Assessment Agency/British Columbia Environmental Assessment Office, May 2014, pp. 18-91, 227-270 and 423-53.

The Terms of Reference state that “the commission must use the forecast of peak capacity demand and energy demand submitted in July 2016.” There is an important distinction between “use” and “rely solely on,” a distinction captured in c(i) and c(ii) regarding developments since that time and other factors that could “influence demand from the expected cases toward the high load or low load case.” Or, it might be said, to even more likely cases below those bounds. While the Commission must ask BC Hydro about its views on these matters, the Commission is not bound to accept those views. In fact, the Commission is effectively required to cast its eye beyond the narrow band of “sensitivity” in the July 2016 forecast if it is to respond fully to the objective in 3(a) of the Terms of Reference.

BC Hydro load forecasting

The issue is that BC Hydro’s 2016 load forecast is no more credible than its numerous predecessors. Despite its frequent claim that their methods are world-class and consistent with the Utilities Commission’s resource planning guidelines,[6] the Authority has regularly overstated reality for the last quarter century and beyond. Indeed, had its forecasts reasonably foreshadowed reality, BC Hydro would not have been able to propose building Site C. Core demand is right where it was in 2005, despite the frequent “hockey-stick” forecasts of BC Hydro. The best presentation of just how far off BC Hydro’s forecasts have consistently been is in the 2017 report from Prof. Bakker’s team at UBC,[7] whose analysis and conclusions are strongly recommended to the Utilities Commission.

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[6] British Columbia Hydro and Power Authority*, Fiscal 2017 to Fiscal 2019 Revenue Requirements Application*, July 28, 2016, 3-3. As a side note, reading the 2016 load forecast document brought on a sense of *déja vu*. The methodology section was almost word for word the same hand-waving, qualitative verbiage that accompanied the 2013 forecast, the basis for the Environmental Impact Statement prepared for the JRP. And that was the same as the material prepared for the 2011 forecast. Apparently, in the face of consistently over-optimistic forecasting, BC Hydro ‘has learned nothing and forgotten nothing.’

[7] R. Hendriks *et al, op. cit*.

Nor does BC Hydro appear to be learning over time. Even its short-term forecasts are systematic overshoots. Its 2015 sales, expressed in GWh, were 3.6 percent below forecast (residential 9.3 percent), and its 2016 sales were 5.1 percent below the 2016 forecast.[8]

Both the UBC report[9] and the JRP Report[10] comment on the institutional reasons for upward bias in utility forecasts, but the former goes one step farther, saying that in the case of BC Hydro's serial errors "the pattern also raises questions about whether BC Hydro's load forecasting was 'strategically optimistic' in order to support a favourable decision by government to develop the Site C Project." The asymmetry in consequences for overshooting or undershooting can be dramatic, as the current CEO of BC Hydro acknowledged in 2014.[11] Whatever the reason, BC Hydro's forecaster's ambition to be low as often as high remains a distant dream.[12]

The principal sources of error appear to be an overly generous forecast of large industrial demand, together with a misunderstanding of price elasticity of demand.

Industrial demand

On the industrial side, a major contribution to the flat-lining of total demand since 2005 has been the 16.8 percent decline since 2006 in large

[8] *Revenue Requirements*, Appendix K, Tables K-1 and K-2, pp. 2-3. The forecast for 2017-2019 is now flat: another over-estimate?

[9] Hendriks *et al*, 14-15

[10] *JRP Report*, 286. See also section 2 of Ansar *et al*, "Delusion and deception in large hydropower dam planning?"

[11] Canadian Environmental Assessment Agency and BC Environmental Assessment Office, "In the Matter of the Joint Review Panel Established to Review the Site C Clean Energy Project Proposed by British Columbia Hydro and Power Authority," *Proceedings at Hearing*, 23 January 2014, Vol. 28, 51. (Accessed 9 August 2017 at http://www.ceaa-acee.gc.ca/050/documents/p63919/98182E.pdf.)

[12] Cited in Hendriks *et al,* 15, note 36

industrial demand.[13] This is principally due to the closure of pulp and paper mills[14] and sawmills, together with a lack of investment in new mines to replace those whose reserves are flagging. Large Industrial demand now lags both Commercial and Residential demand.

The prospect for a rejuvenation of electricity demand from the forest industry is poor. In an effort to sustain employment in light of the mountain pine beetle infestation, as well as increased fire losses and disease related to climate change, the provincial government has increased the annual allowable cut (AAC), but industry has been unable to find enough profitable wood to fill the quota. The economic insect-killed forests were quickly harvested, but so were first- and second-growth forests, the latter in an unsustainable manner. The Ministry of Forests, Lands and Natural Resource Operations sectoral plan for pulp and paper calls for action to "address imminent regional fibre shortages."[15] Timber harvest volume declined precipitously in the period 2006-09 (from 80 to 49 million m^3, principally due to the global financial crisis), before recovering to 70 million m^3 in 2011-2015.[16] This is well below historical norms. With climate change and U.S. trade actions layered on top of inflated AACs and other incentives to over-harvest,[17] the prospect is for further slow

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[13] 2005-06 sales to "Large Industrial:" 16,428 GWh. 2015-16: 13,669 GWh. *BC Hydro Annual Report 2006*, 104; *BC Hydro* 2015/16 *Annual Service Plan Report,* 100

[14] In coastal communities alone, 5 mills closed in the period 1998-2011: Gold River (1998), Port Edward (2001), Woodfibre (2006), Campbell River (2008), and Kitimat (2009). The remaining four thermo-mechanical pulp mills in B.C. are facing difficulties with fibre availability and input costs, among which the cost of power looms large.

[15] www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/forestry/competitive-forest-industry/pulp_and_paper_sept_2016.pdf. After this year's fire season, the 2017 assessment will be even more downbeat.

[16] www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/forestry/forest-industry-economics-state/2015_economic_state_of_bc_forest_sector.pdf

[17] Anthony Britneff, *Vancouver Sun*, 31 July 2017. Vancouver.sun/opinion/op-ed/opinion-policies-work-against-sound-forest-management

decline in timber supply, the loss of more primary manufacturing mills,[18] and a corresponding decrease in electricity demand and employment.

Mines are big power users; in fact, the local availability of ample power has traditionally been a *sine qua non* for new investment. The trouble is that there are few new mines, and power demand declines as older mines are exhausted or fall prey to lower commodity prices. Agreements with First Nations rights holders take time and patience, may involve serious obligations under industrial benefits and other agreements, and the environmental approval process likewise takes time and expense. But miners are ever optimists, and increasingly plan for life-of-mine rather than life-of-business-cycle time periods. Future input costs are as important as commodity prices. In this respect concerns have been raised about the cost of electricity, especially as a new mining prospect may be some distance from the current grid and require expensive new transmission facilities. As grid prices rise, consideration is being given to off-grid power sources, such as local mini-hydro and pumped storage solutions. To the degree this happens there would be a further decoupling of economic growth from electricity consumption.

The previous government had great hopes for the rapid growth of an export LNG industry, but these appear to have been dashed for some years to come. One small electricity-powered project has been licensed for Howe Sound, but a final investment decision has yet to be taken. It lacks the low cost, critical mass and expansion potential that characterizes most global LNG facilities. A small facility at Tilbury Island has made a request for power supply. Elsewhere the prospect is dim. Overwhelmingly, the LNG industry prefers to power its facilities with its own gas. Petronas, one of the largest proponents, has cancelled despite being granted an own-gas exemption to the *Clean Energy Act* and is looking for other ways to monetize its northeast BC gas assets. Others are delaying commitments. Realistically, the only successful

[18] "Major mill power failure looms in B.C.," editorial, *Business in Vancouver*, 14 February 2017

projects in the world are those dominated by associated gas (gas produced along with oil at low or zero cost), where infrastructure is largely in place, and where there are no other markets for gas which would otherwise simply be flared. Existing infrastructure with unused capacity in a deregulated electricity market, as on the US Gulf Coast, helps. And especially in this low-margin industry, a complaisant regulatory and tax framework is important. None of these factors work in favour of BC investment, and as long as LNG prices remain at their current lows, probably for a long time, substantial greenfield investment in BC is unlikely. Were it to happen, the developer would probably insist on generating most of its own power from gas, buying only ancillary power from the grid, and might insist on selling excess to BC Hydro or having wheeling provisions that would allow it to lower its own costs by selling to the same third parties BC Hydro relies on for revenue. In any case, the BC Hydro forecast of sales of 2,148 GWh by 2022 and 2,662 GWh by 2027[19] is simply not credible. As this is 65 percent of the production of Site C, it is highly material—just not believable.

One potential new source of industrial demand is powering the drilling and operation of fracking wells in the Montney Basin. This is not so much a gas play as a condensate development, where the market for condensates for bitumen upgrading is strong and where the prospects for import replacement are good. BC Hydro is marketing to the producers, but prices will be critical and there would be a good deal of transmission and distribution infrastructure to be built. The forecast for the oil and gas sector calls for demand to rise by 133 percent from 2017 to 2027. The 2036 forecast, at 4,100 GWh, is 3.2 times the 2016 actual.[20] It is highly unlikely, however, that power could be sold at the marginal cost of Site C production: see below. Further, licensing may not be easy, as First Nations' concerns about cumulative damage and treaty rights

[19] Revenue Requirements, Table 3-3, p. 3-16

[20] *Ibid*.

will come into play, as will environmental concerns about fracking, water use and contamination, and seismic effects.

Energy demand from the institutional, commercial and residential sectors will sag as prices rise, quite independently of anything BC Hydro may do with demand-side management programs. Flat or only slightly increasing per capita residential demand will be partly but not wholly offset by population increase and the market penetration of electric cars. The latter will be affected by the cross elasticity of demand for liquid fuels, whose prices are affected as much by public policy (carbon and other taxes) as simple technical production cost.

The prospect of helping wean Alberta from coal has had some recent publicity as BC Hydro and the previous government looked ever more keenly for new markets for Site C. But Site C power onsite will cost about $90-100/MWh and require a further $15-20/MWh to transmit to Alberta—where the marginal cost is best illustrated by the cost of the new gas-fired Shepherd Energy facility in Calgary: about $55-60/MWh. In addition, the Alberta electricity producers are not provincially-owned companies, required to enter into politically dictated but uneconomic transactions. So long as natural gas prices in Alberta remain near current levels, it is possible that BC could wholesale power to Alberta utilities at a gross price representing a discount to those already low prices—say $45/MWh. From this would have to be deducted the cost of new transmission, leaving BC Hydro with a netback in the region of $25-30/MWh, a loss of three-quarters of cost.

Coincidentally, $25-35/MWh is about the price realizable from the international spot market, which is what BC can sell power to the US for and what it gets for its Columbia River Entitlement. If the project can rely solely on spot sales for its first 20 years of operation, and spot prices continue at current levels, the 2024 net value of the project would be about $2 billion.[21] Only if the costs to complete are less than this does it make economic sense to continue with the project.

DSM and price elasticity of demand

Price elasticity is a measure of the degree to which customers reduce their consumption because of rising real prices. It varies with the type of good, available alternatives, consumer tastes, and the turnover rate of capital goods used in consumption. Conservation, fuel switching and equipment replacement (appliances, LED lights, heat pumps, etc.) are common responses to electricity consumption as prices rise. Substitution possibilities rise with time and changes in technology, so the relevant measure is long-run price elasticity. In reviewing literature for the JRP Report, I found numbers ranging from -0.1 to -0.7, with a clustering around -0.4.[22] This is consistent with the citations by Hendriks *et al*, who found estimates ranging from -0.29 to -0.97, again clustering around -0.40.[23] BC Hydro, by contrast, uses -0.05 uniformly across all sectors.[24] It assumes conservation essentially doesn't occur without a nudge or bribe from a demand-side measure. If this is the heart of their methodological toolkit, it requires revision. But it must be, for BC Hydro states that "For the residential and light industrial/commercial sectors, the key uncertainty variables are temperature and economic growth."[25] There is no mention of price.

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[21] $1.9 billion at a discount rate of 5 percent; $2.3 billion at 3 percent nominal. Assumes sales of 5,100 GWh at $30/MWh.

[22] Shu Fan and Rob Hyndman, "The price elasticity of electricity demand in South Australia," Working Paper 16/10, Dep't of Econometrics and Business Statistics, Monash University, August 2010, accessed 10 August 2017 at http://mon.clients.squiz.net/business-mango/econometrics-and-business-statistics/research/publications/ebs/wp16-10.pdf. Paper provides an international literature review as well as measures for South Australia.

[23] Hendriks *et al*, Table 2, p. 26

[24] *Revenue Requirements*, p. 3-4, footnote 29

[25] *Revenue Requirements*, p. 3-12

The effect of price elasticity on demand cannot be estimated without an assumption, or an estimate, of the course of real prices over the long term and without a financial model of BC Hydro from which revenue requirements can be calculated. BC Hydro has not published such an estimate, perhaps in part because it has been constrained by the government-imposed “10-Year Rate Plan.”[26] BC Hydro’s real revenue requirements over the long term include the paying down of its deferral accounts and the reconstruction of the asset side of its balance sheet, both matters which will surely engage the Commission in coming years. As it stands, BC Hydro must use “deemed” equity, since by either FASB 980 or Canadian GAAP standards, its nominal equity is exceeded by its net regulatory accounts. Some of these are assumed but unapproved rates which are to be paid years from now. They are counted as assets in the present, thus giving a false impression of BC Hydro’s financial condition.[27] Net regulatory assets were carried at $5.597 billion at 31 March 2017.[28]

The trend is clear, however. Real prices are on the rise, after a long period of relative stability. This will affect total, not just marginal, demand. At expected price elasticities (around -0.4) the effect will overcome population and GDP growth, resulting in continued static or depressed demand for decades to come.

Demand-side management is distinct from price elasticity. It involves changes to codes and standards, the introduction of rates that help manage

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[26] *Revenue Requirements*, pp. 1-16 to 1-18

[27] BC Hydro’s financial position is bad and getting worse, largely because of the manipulation of accounting and regulatory standards and the taking of large sums from the Authority in order to produce spurious balanced books at the provincial level. See Richard McCandless, “Rate suppression and debt transformation: the political use of BC Hydro 2008 to 2014, *BC Studies*, Fall 2016; R. McCandless and H. Swain, “Hydro pricing: what the minister didn’t tell us,” *Times-Colonist*, Victoria, 23 August 2016, A9; Vaughn Palmer, “Hydro deferral ‘rat’ keeps getting bigger, *Vancouver Sun*, 7 August 2016; Arthur Caldicott, “From showcase to basket case,” *Island Tides*, 11 August 2016; David Bond, “Liberals leave financial mess for new gov’t to clean up,” *Kelowna Daily Courier*, 6 June 2017

[28] BC Hydro, *Annual Service Plan Report 2016/17*, 22 August 2017, p. 64

loads,[29] load shedding arrangements with big customers, and the subsidization of more efficient end-use applications like appliances or lighting. BC Hydro confounds the two, implicitly assuming that customers require an explicit subsidy or prohibition before any meaningful demand reduction will happen. In the short term, bewildered by an unexpected elasticity response, BC Hydro has cut its expenditures on DSM to save cash. It is thus in the anomalous situation of paying Independent Power Producers vastly more (currently $88/MWh) under their long-term contracts than it would cost to procure more conservation. Anticipating an argument below, it is clear that BC Hydro can meet any likely shortfall in supply by ramping up DSM again, especially if BC Hydro takes advantage of the encouragement to use rate structures embodied in s. 2(b) of the *Clean Energy Act*.

Recent events regarding demand

Since the publication of the July 2016 forecast, several notable things have occurred. The prospect for a BC LNG industry has collapsed. The prospect for electrically powered automobiles has brightened, though it will be many years before the load is material in the context of the whole BC system, as BC Hydro (and I) believe. The low prices of liquid fuels, if continued, may slow the market penetration of electric cars and work against the electrification of the mountain divisions of CN and CP. Off-gridding will likely become important as the price of residential and commercial photovoltaics and storage continues to decline, as in the United States.[30]

The plateauing of demand and the decoupling of economic growth from power consumption has become more apparent across North America and in B.C. Annual US total residential sales are down 3 percent since 2010, with per

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[29] In the U.S., the use of rates to shape loads has been the dominant form of DSM for a generation. (Charles River Associates, Primer on Demand-Side Management, World Bank, Washington, D.C., February 2005). BC Hydro has some distance to go to catch up.

[30] Ivan Penn and Ryan Menezes, "Californians are paying billions for power they don't need," *Los Angeles Times*, 5 February 2017

capita sales down a whopping 7 percent—in a period of strong economic recovery.[31] This is more than just weather. Reactions to rising prices are playing a big part. Investor-owned utilities in the U.S. have become sensitive to financing covenants which were predicated on higher sales and prices, with some experiencing financial distress. To protect their revenues, some utilities are pressing state governments to reverse net metering arrangements.[32] The recent cancellation of two nuclear power units under construction in South Carolina is a consequence of flagging demand and cost overruns.[33] The US $9 billion loss on the 40 percent completed reactors is already falling to customers in the form of sharply higher rates, which will further moderate consumption. In Canada, the financial distress of Nalcor and Manitoba Hydro (and their government owners) has become sufficiently acute as to threaten Manitoba's long-standing number two spot in low Canadian electricity prices, behind Quebec but ahead of B.C., and to require federal loan guarantees to back up the financially disastrous Muskrat Falls project. Note that both got in trouble in part because of premature reliance on US markets. Manitoba Hydro's power purchase agreements with US utilities were cut back by US public utility commissions, and Nalcor has no such agreements at all. Quebec Hydro, in contrast, will not invest in new projects until all customer regulatory hurdles are settled and contracts signed. Quebec's credit rating was recently upgraded, and is now better than Ontario's.

On the evidence of BC consumption, as well as per capita consumption all over North America, the low-growth forecast of BC Hydro is highly unlikely to be met. A better base-case scenario would be zero growth for the next decade.

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[31] "Per capita residential electricity sales in the U.S. have fallen since 2012," *Today in Energy*, U.S. Energy Information Administration, July 26, 2017

[32] Hiroko Tabuchi, "Rooftop Solar Dims under Pressure from Utility Lobbyists," *New York Times*, 8 July 2017

[33] Brad Plumer, "U.S. Nuclear Comeback Stalls as Two Reactors are Abandoned," *New York Times*, July 31, 2017. Accessed August 8 2017 at nytimes.com/2017/07/31/climate/nuclear-power-project-cancelled-in-south-carolina.html

Supply alternatives

(Terms of Reference 3(b)(iv))

Columbia River Treaty entitlement

BC Hydro receives about $30/MWh for refusing Canada's entitlement under the Columbia River Treaty. At present, BC Hydro accepts delivery of more than 1,300 MW of capacity (4+ TWh of energy, or 80 percent of Site C) at the border and instantly sells it back to the U.S. at spot market prices. The only reason for this nonsensical transaction is the prohibition in the B.C. *Clean Energy Act* of 2010, a prohibition that commands autarky (in a trading province, no less) and forbids considering, as part of our reliable supply, power promised under a treaty with the United States government that has provided immense benefits to both countries over more than half a century. Either side can denounce the treaty with ten years' notice, but that is hardly likely; and even were it to occur, ten years is plenty of time to arrange alternative supply.

The Commission should not be bound by a narrow reading of 3(b)(iv). It should follow the lead of the Government which, when some *CEA* objective was found infeasible or embarrassing, promptly changed it: note the decision following the recommendation of deputy ministers regarding the definition of self-sufficiency to specify that B.C. had to be self-sufficient in an average-water year rather than a critical-water year, or the decisions to abandon the greenhouse gas targets in the *Act* for the benefit of the LNG industry.[34] Note also that some objectives are in conflict with each other, especially with the emphasis on being one of the lowest-cost jurisdictions in North America,[35] and

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[34] The Order-in-Council of 26 November 2013 allowing the LNG industry to stay uncoupled from the grid and thus ignore the greenhouse gas limits in the CEA "violates the inviolable Section 2(m) of the *Clean Energy Act*." *Proceedings at Hearing*, 23 January 2016, Vol. 28, 76. The *JRP Report* at 302-303 lists six substantial deviations from the *Act*.

[35] *Clean Energy Act* [SBC 2010] Chapter 22, section 2(f)

therefore that absolute language must be qualified. In fact, the *Act* was designed to be malleable, in the wide discretion given to the Minister and Cabinet to change things by regulation.[36] The Table of Legislative Changes records many changes that go beyond mere regulation.[37] The Commission should conclude that the Columbia River Entitlement, a block of power of the same size and general characteristics of reliability, firmness, shapeliness, and effect on greenhouse gases as Site C at a quarter of the cost would be a prime source of new power, should we need it.

Price-induced conservation

Conservation can be relied on to provide a much greater contribution to load balancing than BC Hydro's forecasts indicate. A first step would be to calculate the effect of present and future price increases on demand, using reasonable estimates of elasticity. An elasticity of -0.4 (or any other number well-grounded in empirical reality) would be a good place to start, with sensitivities calculated around that as a mean. As noted, this can only be done given price forecasts of the sort that BC Hydro keeps secret but the Commission can uncover, or make itself.

To that should be added the contribution expected from classic DSM. Note that average annual KWh use per residential account has been declining slightly over the last twelve years.[38]

Wind, solar, geothermal

The contribution from individually smaller renewable energy projects (wind, solar and smaller hydro projects in the short term, geothermal in a decade or so) can in aggregate be quite large at prices less than Site C. They have the additional virtue of not creating large surpluses in their initial years,

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[36] *Clean Energy Act*, s. 35(d)

[37] *Ibid*, Table of Legislative Changes (2nd and 3rd editions), accessed 10 August 2017 at bclaws.ca/civix/document/id/complete/statreg/e2tlc10022 and e3tlc.

[38] *2016/17 Annual Service Plan Report*, 105

or decades, which have to be dumped on the spot market. BC Hydro has identified a number of wind opportunities whose individual intermittency is substantially mitigated by the great geographical sweep of the province. Solar prices are declining quite rapidly, and as with wind, their intermittency is mitigated not only by geography[39] but also by the fact that BC Hydro's great storage capacity in its reservoirs, especially outside of the freshet, allows the integration of more intermittent sources than less fortunate systems.

The story of geothermal energy is well known to the Commission, which advised BC Hydro to seriously examine the possibility when it turned down Site C in 1983. BC Hydro did not do so. This missed opportunity was noted in the JRP Report.[40] In the decades since 1983, the attractiveness of Coast Range hot rocks may have declined against the possibility of cooler groundwater (up to 140°C) in the Peace River sedimentary basin, but neither have been fully investigated, the latter in part because BC Hydro seems not to talk to the oil and gas industry. The bottom line for the moment is that BC Hydro's estimate in the Environmental Impact Study prepared for the 2013-14 review is that up to 700 MW of firm power may be available at competitive prices from B.C. geothermal resources. However, after 34 years, all the basic resource characterization and technology development has been left to the private sector. The periodic claim that the technology is unproven is belied by routine operations in Italy, New Zealand, California, Alaska, Iceland, and elsewhere.[41]

Short-term demand spikes can be accommodated in a variety of ways: through the spot market, with single-cycle gas turbines operated perhaps 10-20 days a year, through load-shedding agreements with industrial customers, even through time-of-day pricing or moral suasion. During the JRP hearings we

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[39] *JRP Report*, pp. 294-5

[40] *JRP Report*, p. 299

[41] "The International Geothermal Association…reported that 10,715 [MW] of geothermal power in 24 countries is online, which was expected to generate 67,246 GWh of electricity in 2010." Wikipedia, "Geothermal Energy"

were told by BC Hydro, somewhat impatiently, not to worry about “needle peaks,” as there were a number of ways of dealing with these.[42]

BC Hydro, as noted in the JRP Report,[43] uses biased methods to calculate the cost of power from various sources, and these biases have increased since the Panel Hearings. Unsurprisingly, all the biases work in favour of Site C. BC Hydro uses a corporate WACC (weighted average cost of capital) to discount cash flows, instead of a social discount rate, as is proper in cost-benefit analysis—and then says that because no corporate equity will be attributed to Site C (because they really haven’t any, only “regulatory accounts”), artificially decreasing the cost of the project. It adds taxation to the cost of IPP (independent power producer) proposals, but taxation is excluded from cost-benefit analysis as it is a benefit to the general public. It adds an arbitrary $5/MWh or more[44] to all IPP proposals for the cost of capacity back-up, regardless of the quantity or quality of intermittent sources, and despite asserting elsewhere that needle peaks are not a concern.

The biggest whopper, introduced only recently, is said to reduce the $83/MWh[45] on-site cost of Site C power by no less than $26. This is the assertion that Site C can be built without expensive equity and with 70-year financing at less than 3 percent. In corporate finance, equity is the buffer between unexpected realities and bankruptcy. BC Hydro is merely outsourcing this risk to the general BC taxpayer. They are not making it go away. And as for financing billions at current rates, the risk is overwhelming that refinancing costs during a 70-year term will be significantly higher than they are at

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[42] *Proceedings at Hearing*, 23 January 2014, Vol. 28, 22-23. (Accessed 9 August 2017 at http://www.ceaa-acee.gc.ca/050/documents/p63919/98182E.pdf.)

[43] *JRP Report*, pp. 297-98

[44] In the present value analysis of the “Clean + Thermal” portfolio in the EIS there was a $10/MWh “integration” charge *plus* thermal back-up.

[45] BC Hydro’s number. I believe the number will be at least $90/MWh, depending on the Commission’s conclusions about cost to complete.

present. Transferring these risks to the taxpayer owners of the company without compensation is irresponsible financial sleight-of-hand.

In comparing the alleged costs of Site C and its alternatives, the Commission must use sound methods and a level playing field: see Appendix.

Better use of existing assets

Hydroelectric dams have lifetimes of 75 to 150 years, with modest maintenance requirements, but their electromechanical components typically need mid-life overhauls or even replacement every 30-50 years, and their connecting transmission lines every half-century or so. Of BC Hydro's 23 smaller generating stations, only two (John Hart and Ruskin) have recently been refurbished, but together the 23 supply 11 percent of generating capacity and (in 2016) 8.65 percent of power. Many of these aging smaller assets can be improved with new-design turbines and operating regimes better suited to grid needs with no increase in footprint—a major advantage from a licensing point of view—and with major capital long paid for. Some of this appears in current capital plans.

Revelstoke 6 still awaits turbines, and the Duncan dam is used solely for storage. Adding capacity should be inexpensive and quite valuable to the system. And they have the same footprint and sunk capital advantages as the smaller dams.

Costs to ratepayers

(Terms of Reference 3(b)(ii, iii))

In considering the costs to ratepayers, the Commission will want to assess the increasingly parlous financial condition of BC Hydro and the possible need to rebalance debt obligations between the province and the authority, and to advise returning to Canadian GAAP as an accounting standard. In recent years the provincial government has required the payment of dividends, water rentals, and other payments which could not be paid for from free cash flow, especially since the province by Order-in-Council limited the amounts BC Hydro could recover from customers while decreeing what net income must be. The consequence has been that BC Hydro has borrowed to finance these payments, and has set up deferral accounts not approved by an independent regulator, as the basis for its accounting standard, FASB 980, requires. The province regularized this highly unusual process by further Orders-in-Council, all with a view to producing an illusory balance to the provincial budget.[46] The financial structure of BC Hydro is not sustainable within the model of an arm's-length professionally managed Crown corporation, though this is still the officially stated intent. Its debt is too large, its deferral accounts larger in proportion to assets than any other utility I know, and it is getting deeper into the hole under the Ten-Year Plan imposed by the province. Adding Site C at 100 percent debt to existing obligations of $20 billion,[47] as BC Hydro has suggested,[48] will render the *Clean Energy Act* objective of highly competitive rates unattainable. The Commission should consider whether the portion of that debt related to unusual provincial takings should be shifted to the provincial account—the province already guarantees it—so that a reformed BC Hydro can continue to offer reasonable rates, if not as competitive as they might be without Site C.

Most importantly, the very high rates that would be a consequence of continuing with the present financial structure would only accelerate the

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[46] Richard C. McCandless, "Rate Suppression and Debt Transformation: The Political Use of BC Hydro, 2008 to 2014, *BC Studies* 191 (autumn 2016) 9-33. McCandless has published a number of highly relevant "occasional papers" on www.bcpolicyperspectives.com. No. 34, for instance, notes that power costs in two provinces that have made similar mistakes as BC will rise dramatically: by 100 percent between 2016 and 2030 in Newfoundland, and by 46 percent between 2017 and 2021 in Manitoba. Quebec will be left as the only province with attractively low rates, and Canada as a whole will have blown an important competitive advantage.

[47] *2016/17 Annual Service Plan report,* p. 72. This figure does not include $6.3 billion of "regulatory assets," much of which is assumed but unapproved future revenue accounted for as present assets.

[48] British Columbia Utilities Commission in re British Columbia Hydro and Power Authority 2015 Rate Design Application, *Proceedings*, 17 August 2016, p. 676. Note the daring in assuming 70-year financing, with no equity, and at fixed interest costs at present levels.

decline in demand from which the Authority is already suffering. Leaving the current structure in place will cost many more permanent jobs, perhaps first in thermo-mechanical pulp mills, than Site C would temporarily create.

Too many assumptions about BC Hydro's costs, revenues, treatment of regulatory accounts and costs of capital are required to forecast rates in 2024 or 2030, but it seems clear that those rising costs will have to be paid for from a relatively static number of GWh of sales.

Conclusions

1 Only BCUC can compel the production of documents from BC Hydro relating to sunk costs and costs to complete. Since these figures are not accessible to intervenors, they (and the Government) must rely on independent work by the Commission itself on whether we have passed the point of no return.

2 From a financial point of view, the point of no return is the point at which projected total costs less the sum of allowable past expenditures and irrevocable commitments equals the present value of the stream of projected revenues from the project. Only the Commission can make these calculations.

3 Likewise, only the Commission can compel the production of information about the future financial condition of BC Hydro that will govern rates. The Commission cannot simply adjudicate among submissions received in this review. It must undertake its own research and analysis.

4 BC Hydro's load forecasting is not remotely investment grade. It consistently, and by large margins, over-estimates demand, and the over-estimates get larger the farther out they go. They are utterly inadequate as the basis for multi-billion dollar decisions, and cannot be relied on for business planning purposes.

5 Price elasticity will seriously lower demand, though by how much depends on the future trajectory of real prices, another matter that only the Commission is in a position to estimate. The contribution of demand-side measures has been lowered by a deliberate decision by BC Hydro to disinvest, a consequence of the need to conserve cash brought on by government exactions.

6 Conservation is the cheapest source of electricity. BC Hydro should “buy” conservation up to the cost of new supply. Backing away from DSM is evidence of their current confusion.

7 Demand will not materialize at even the low limit of BC Hydro’s demand forecast. It will be many years before new supply for domestic purposes is necessary; when it is, there are numerous sources that are less expensive than Site C.

8 In considering impacts on ratepayers, the Commission should have regard to the fall in electricity demand and industrial dislocation that would attend continuing the disastrous financial condition of BC Hydro imposed arbitrarily by the provincial government.

9 Solely from a financial point of view, unless the cost to complete is less than $2 billion, the project should be cancelled immediately and the landscape restored to a sustainable shape. The Flood Reserve of 1957 should be rescinded, and expropriated properties returned with no losses, broadly considered, to their owners.

Appendix:

Sharp practice at BC Hydro

The Joint Review Panel concluded the "Site C would be the least expensive of the alternatives, and its cost advantages would increase with the passing decades as inflation makes alternatives more costly," (p. 305) and "that a number of supply alternatives are competitive with Site C on a standard financial analysis, although in the long term, Site C would produce less expensive power than any alternative" (p. 298).

The BC government and BC Hydro have repeatedly quoted these conclusions since 2014 in BC and federal litigation and in public relations materials. BC Hydro used them in its response to a critical article in the *New York Times*[49] and in response to criticism from *Business in Vancouver*.[50]

These May 2014 conclusions were made obsolete by the Final Investment Decision of December 2014, which raised the cost estimate from $7.9 billion to $8.8 billion. The conclusion had been based on the proponent's present value analysis showing Site C with a $150 million advantage over the alternative portfolio called the "Clean + Thermal Block," and from a similar advantage based on unit energy cost. But the increase in price neutralized the $150 million advantage.

Further, the "least expensive" conclusion was reluctantly based on the claimed 5 percent cost of public capital vs. the 7 percent cost of private capital. From the *JRP Report*, p. 297: "BC Hydro, abetted by BCUC, skipped the cost-benefit phase and went directly to present valuing alternatives. It ascribed a weighted average cost of capital (WACC) of 5 percent to itself and 7 percent (down from 6 and 8 in the EIS) to independent power producers, with the difference put down to the higher cost of capital the latter must face. Yet a principal reason private power producers face higher costs of capital is that they bear most performance risks. In BC Hydro's case, those risks are no less real but are borne by the customer or taxpayer, not BC Hydro. This is no

[49] BC Hydro, "BC Hydro responds to Dan Levin of The New York Times," *News*, 13 December 2016

[50] Dave Conway (Community Relations Manager, Site C Clean Energy Project, BC Hydro), "Site C presents better long-term value of British Columbians," Business in Vancouver, 15-21 November 2016, p. 33

reason to artificially reduce BC Hydro's WACC, especially if it is to be used as a surrogate for the [social discount rate]."

The distortion was later amplified when BC Hydro proposed to finance Site C over 70 years at 3 percent, an absurd differential of 4 percentage points, and an unprecedented tenor. When in response to questions from the Panel, BC Hydro recalculated present values by decreasing the WACC discrimination from 2 to 1 percent point, the advantage of Site C dropped to a mere $20 million (Table 5, p. 14 of JRP Info Request 77a, October 2013).

The JRP conclusion that Site C would be cheaper in the long run was based on an assumption of conventional financing over 35 years. As the facility would have a lifetime at least three times that period, it would appear to the consumer of 2060 and beyond rather like the Heritage assets of today: a generous gift from the past.

PartnershipsBC agrees that BC Hydro's calculation methods are inappropriate. "The public sector's long-term borrowing rate, therefore, is an inappropriate estimator of the true cost of capital essentially because it only reflects the cost of raising capital, which can be very different from the cost of using that capital. The public cost of raising capital does not include the full cost implications of retained project risk, nor does it typically include the cost of amortizing the debt. For example, if the public sector's long-term cost of borrowing is five per cent, when the project risk implies that an Internal Rate of Return of seven per cent is required by the private sector, taxpayers are in effect subsidizing the traditionally procured project by covering the potential additional cost of the risks associated with the project. Taxpayers are often not aware of this exposure to the true risks of a project, nor to the implied subsidy they are providing. It is usually only in the case of large cost overruns and project failure that taxpayers realize the cost implication of the public's exposure."[51]

[51] Partnerships BC, "Methodology for Quantitative Procurement Options Analysis," Discussion Paper, April 2014

Two conclusions from the JRP Report seem, however, to have enduring value:

- "The Panel cannot conclude on the likely accuracy of Project cost estimates because it does not have the information, time, or resources. This affects all further calculations of unit costs, revenue requirements, and rates" (p. 280)
- "BC Hydro has run these two stages together, with the result that the Panel cannot be confident that IPP alternatives vs. BC Hydro alternatives, or supply vs. demand management alternatives, are accurately valued" (p. 297)

BC Hydro made highly material changes to its financial plan after the Joint Review Panel concluded its work but quoted the Panel Report as if these changes had not been made. This is not honourable behaviour.