

2.1.0 Reference: SCHEDULE B ELECTRICITY PURCHASE AGREEMENT – TERM SHEET - LARGE PROJECTS p. 5 “post-COD price”

Context: The EPA Term Sheet requires bidders of intermittent resources to submit a monthly firm energy amount and differentiate the total amounts provided and prices into firm versus non-firm components. The relative amounts and prices may or may not be related to BC Hydro’s requirements and opportunities.

The Pacific Northwest Power Planning Council has defined Firm Energy Load Carrying Capability (“FELCC”) as *“The amount of firm energy that can be produced from a hydropower system based on the system’s lowest recorded streamflows and the maximum amount of reservoir storage currently available to the system.”* and *“firm energy”* as *“electric energy that is considered assurable to the customers to meet all agreed upon portions of the customers load requirements over a defined period.”*

- 2.1.1 Please provide any studies for the BC Hydro system that estimate incremental monthly/seasonal/annual FELCC when intermittent resources are added to the system.
- 2.1.2 Please provide a rationale for determination of the firm versus non-firm total amounts requested in the Call. Please identify if the rationale is based only on the objective of serving firm load versus optimizing trade revenue, subject to serving firm load.
- 2.1.3 What amounts of incremental FELCC, if any, does BC Hydro attribute to wind and small hydro resources of the kinds that may typically be expected to bid in the F2006 Call? How are these amounts derived?
- 2.1.4 Please provide examples of other utilities that require intermittent renewables to contract to a monthly firm energy amount.

2.2.0 Reference: SCHEDULE B ELECTRICITY PURCHASE AGREEMENT – TERM SHEET - LARGE PROJECTS p. 5 “post-COD price”

Context: Tier 1 non-firm prices apply to generation at 100% to 200% of firm bid volume. Tier 1 non-firm price is “applicable firm energy price less a specified \$/MWh discount (escalated at CPI and seasonally adjusted based on a HLH/LLH table)” Tier 2 pricing is a function of spot market prices.

- 2.2.1 What is the basis of the break point between Tier 1 and Tier 2 supply? Please provide any studies relating to determination of the break point.

2.2.2 Upon what basis and using what analysis will BC Hydro determine the discount applying to Tier 1 supply? Please provide any studies relating to estimation of the discount. If the information applies to discounts for other systems, please indicate if or how these are to be adjusted to apply to BC Hydro.

2.2.3 What is the basis of the 70% factor applying in Tier 2 pricing? Please provide any supporting analysis.

2.2.4 Please provide examples of utilities that require wind projects to assume spot market price risk for a portion of the project's output.

2.3.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 3, lines 13-15

Ms Hemmingsen states that *“Firm energy has been defined for the purposes of the F2006 Call to represent a volume of energy, with a contractually assured delivery, that an IPP must commit to providing over a specified period.”*

2.3.1 What is the definition of Firm energy, or whatever analogous concept is used to describe *“assured”* energy, for a BC Hydro project such as Aberfeldie, where there is no reliance on contractual financial penalties to assure the delivery? What level does this *“assured”* energy correspond to in terms of the range of dry to wet years used by BC Hydro for planning purposes? (i.e. Is it the driest, the wettest, the average, the median, the 5th percentile, the 10th percentile, or something else?)

2.3.2 What level of energy delivery is considered to be Firm or *“assured”* for the Aberfeldie project? Please give the monthly schedule of expected Firm or *“assured”* energy deliveries, for the year F20011, from the various size options for the Aberfeldie project, which we believe range from 5 MW to 30 MW.

2.4.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 6, lines 5-8

Ms Hemmingsen states that *“The BC Hydro 2005 REAP demand/supply balance, from which the DPP project energy has been removed, forecasts a supply shortfall of 1,600 GWh in F2011. The 2005 REAP did assume 800 GWh/year of firm energy deliveries in F2011 from the F2006 Call.”*

2.4.1 Will the size of the F2006 Call be amended to increase the minimum firm energy sought in the Call, from 800 GWh/year to 2,400 GWh/year in order to reduce or eliminate the expected shortfall of 1,600 GWh per year? Please describe exactly how much energy, both firm and non-firm, BC Hydro will be seeking to acquire with this Call.

2.4.2 In the *“2005 REAP demand/supply balance”* referenced by Ms Hemmingsen, what is the amount of energy assumed to come from the Aberfeldie project in F2011? Please give the annual and monthly energy amounts assumed to come from Aberfeldie in F2011. Does this amount represent a dry year, a wet year, an average year, the median

year, or exactly what water conditions are assumed for the purposes of the demand/supply balance?

2.5.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 6, lines 16-22

Ms Hemmingsen states that *“The F2006 Call does not include the following resource types that are currently provided for through other BC Hydro initiatives:*

- *BC Hydro plant efficiency improvements (Resource Smart),*
- *Conservation and energy efficiency (Power Smart),*
- *Load Displacement-style customer-owned generation, and*
- *Down-Stream Benefits.”*

2.5.1 For purposes of the “2005 REAP demand/supply balance”, how much energy is BC Hydro forecasting to receive in F2011 from each of the above 4 bulleted items? If more than one project is involved in each bullet, please give a breakdown of the projects involved. If confidentiality agreements prevent naming the specific projects, please just identify them with fictitious names such as “Project A”, or group them in pairs and refer to them as “ProjectA&B”, “ProjectC&D”, etc.

2.5.2 What level of assurance does BC Hydro ascribe to the energy from each of the projects itemized in 2.3.1? Please characterize them as a) assured, if project energy delivery is part of an existing agreement in principle, and will be contractually assured by financial obligations involving compensation for failure to deliver, b) probable, if the projected energy delivery is based on a specific existing project agreement in principle, but the energy delivery will not be contractually assured, c) projected, if the projected energy delivery is based on an anticipated successful negotiation, in the absence of an existing project agreement in principle, or d) speculative, if the plan to acquire this energy is not yet in the implementation stage.

2.5.3 Would any of the above resources be considered Firm energy under the definition in the F2006 Call? If not, how would they be characterized relative to firmness?

2.5.4 What competitive processes will these alternative resources follow? Please provide the corresponding evaluation criteria, term sheets and standard contracts for conservation and energy efficiency (Power Smart) and load displacement-style customer-owned generation. Please provide full and complete copies of the contracts that BC Hydro entered into with Canfor and Weyerhaeuser for load displacement projects at paper mills.

2.6.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 7, line 23

Ms Hemmingsen states that *“...BC Hydro needs to ensure that the supply contracted under EPAs carries firm delivery commitments and that new supply does not detract from the value of the existing system.”*

- 2.6.1 Please explain how new energy deliveries could “*detract from the value of the existing system.*” What is meant by this expression and how could it arise. Please give a factual example.
- 2.6.2 In order to illustrate the point, please explain how an incremental 200 GWh delivered in Nov 2004 LLH would have been handled by the system, including any impact on imports or exports, or operation of the storage dams. Similarly, please explain how 200 GWh delivered in Feb 2005 HLH would have been handled by the system. Please explain how these two events would have a different value to the system and the cost or revenue implications to BC Hydro.
- 2.6.3 What has changed in BC Hydro’s 11,000 MW Integrated System or System Management to warrant the sudden emphasis on Firm/Non-firm for IPP projects, of which the majority are 5 to 25 MW, and may be based on renewable intermittent energy sources.

2.7.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 7, line 29-34

Ms Hemmingsen states “*The hourly firm option is intended to incent bidders to provide a higher-value ‘capacity rich’ product, if available, by providing a \$3/MWh evaluation credit adjuster for such projects.*”

“*The basis for the additional value ... is the levelized cost of Revelstoke Unit #5, inclusive of forgone system benefits to BC Hydro, a proxy for BC Hydro’s cost of incremental intra-day system capacity.*”

- 2.7.1 Please explain why hourly firm is considered “*capacity rich*” relative to monthly firm. How would the system perform differently and what are the cost savings if hourly firm was available?
- 2.7.2 Please explain the phrase “*inclusive of forgone system benefits.*” What are these system benefits and under what circumstances are they foregone? Why do they affect the levelized cost of Revelstoke 5?
- 2.7.3 Explain the calculation of \$3/MWh as it pertains to Revelstoke 5. What is the rationale for linking the value of hourly firm to the cost of Revelstoke 5? Would the availability of hourly firm defer the need for Revelstoke 5?
- 2.7.4 Why was the capacity available as part of the Down Stream Benefits not used as the proxy?

2.8.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 8, line 11

Ms Hemmingsen states “*...BC Hydro is proposing in the F2006 Call to limit the relative amount of non-discretionary firm energy that it purchases in the months of April through July to 1/3 of the total annual volume of firm energy tendered.*”

2.8.1 Since this *'Spring Cap'* will result in the sub-optimization of the resource, can you please explain in detail the calculations behind the creation of this cap on Spring firm energy.

2.9.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 12, line 5 and page 30, line 16

On page 12 Ms Hemmingsen states “...*a CFT process: ...provides bidders with greater certainty that BC Hydro will proceed to award*”, whereas on page 30 she states that “*BC Hydro will reserve the right in its discretion to cancel the CFT process before award of any EPA, and to award no EPAs*”

2.9.1 Please explain how this amount of sole discretion on the part of BC Hydro can possibly give bidders “*greater certainty that BC Hydro will proceed to award.*”

2.9.2 In light of the recent Duke Point project cancellation, how do the bidders have any certainty that BC Hydro will actually follow through even if it does make an award?

2.9.3 Will there be contractual guarantees by BC Hydro, with financial penalties to compensate developers if BC Hydro cancels the Call without an award, or fails to undertake a project after an award is given?

2.10.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 14, line 3-6 and page 16, line 32 re Split Bids

On page 14, Ms Hemmingsen states “*Split bids should increase the pool of potential bidders by facilitating larger projects producing energy in excess of that which would be purchased by BC Hydro pursuant to the F2006 Call.*” On page 16 she adds “*..thereby increasing the pool of potential bidders and competitive tenders.*”

2.10.1 How is it presumed that these larger projects will be able to market this additional non-firm energy when, under the proposed terms in BC Hydro’s Transmission Service Rate Application, they will have no access to large industrial customers either

- a) through the BCTC OATT, because any industrial customer choosing to buy from a 3rd party supplier will be cut off from paying the heritage rate on any of this power, or
- b) through BC Hydro’s NITS system, because they would be required to provide firm energy deliveries forecasted at least a year in advance, when the project will only have residual non-firm energy, since it will already be selling all its firm energy pursuant to the F2006 Call?

2.11.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 31, line 9 re levelized bid price

Ms Hemmingsen states “*Phase 2 (of the evaluation methodology) involves calculating the levelized bid price for those tenders passing Phase 1.*”

2.11.1 For greater clarity, please explain in detail exactly how this levelized bid price will be calculated.

- 2.11.2 For the following two examples, please show the calculation of levelized bid price for each.

		Project 1	Project 2
Bid Price		\$60	\$60
Term		25 years	25 years
Escalation		50% of CPI	50% of CPI
Tendered Firm energy	Jan	4 GWh	25 GWh
	Feb	3	20
	Mar	3	12
	Apr	6	5
	May	12	5
	Jun	14	5
	Jul	16	5
	Aug	32	5
	Sep	24	5
	Oct	14	12
	Nov	10	20
	Dec	6	25
	Annual	144 GWh	144 GWh

2.12.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, page 22, line 30 and Exhibit C page 14 re Shortfall LDs

Ms Hemmingsen states *“The shortfall LDs for monthly and hourly firm delivery shortfalls are mark-to-market LDs based on a comparison of the adjusted bid price to the Mid-Columbia (Mid-C) price (capped at \$100/MWh escalating at CPI), plus transmission charges from Mid-C to the border.”*

- 2.12.1 Please explain the meaning of adjusted bid price in this calculation. Show how it would be calculated for the examples in 2.10.2.
- 2.12.2 Assuming a Mid-C price equal to the \$100 cap (assuming 3% for CPI), show the calculation of the maximum LDs for each of the example projects in 2.10.2 for the years F2011 and F2031.
- 2.12.3 Why is the Mid-C cap of \$100/MWh increasing at 100% of CPI, when the bidder’s price can only escalate at a maximum of 50% of CPI? Won’t this lead to an ever increasing potential liability? How wide will the gap grow in 40 years for a bid price of \$60/MWh?

2.13.0 Reference: BCH 2005 REAP – Exhibit B-11 – Direct Testimony of Mary Hemmingsen, Exhibit C, page 11-12 re Non-Firm Energy Price – Large Projects

Exhibit C states that the Tier 1 price for Non-firm energy “is expected to range from \$8/MWh to \$12/MWh” and *“is based on the levelized cost of Mica Unit #5, inclusive of forgone system benefits to BC Hydro.”*

- 2.13.1 Please explain the phrase “*forgone system benefits*” and give some specific examples to explain where they come from, how much they are, and how they are involved in the calculation of the non-firm discount.
- 2.13.2 What is the rationale for using Mica 5 here but Revelstoke 5 for the hourly firm premium? What is the difference between the two and why is Mica relevant for the non-firm discount, but Revelstoke relevant for the hourly firm premium?
- 2.13.3 Show how this Tier 1 discount would be calculated if, for example, the costs, firm energy, and dependable capacity of Mica Unit #5 were as described in the Resource Options Report prepared for the 2005 IEP, making an appropriate allowance for the foregone system benefits as described in 2.14.1.

2.14.0 Reference: General

Not including any matters relating to the Duke Point Project, how much has BC Hydro paid since August 2001 to outside law firms for advice with respect to IPP calls including without limitation the preparation of contracts that IPPs have been required to sign? How much has been spent with respect to the call that is the subject of the REAP application?

12.15.0 Reference: General

Please provide copies of the standard form contracts that BC Hydro used to acquire electricity from IPPs in the late 1980’s and early 1990’s.

Copies of Standard form run of River contracts from early 1990’s

Outside legal fees since 2001 other than Duke Point.