2002/03 GREEN POWER GENERATION CALL FOR TENDERS CONTRACTED CAPACITY TUTORIAL

QUESTIONS & ANSWERS

Introduction

This document contains an edited version of the Questions and Answers at the 23 May 2003 Green Power Generation Call For Tenders Contracted Capacity Tutorial.

Questions and Answers have been edited for clarity and accuracy. Similar questions and answers have been consolidated into a single, comprehensive question and answer. Only those questions and answers posted on the web site (www.bchydro.com/greenipp) become part of the 2002/03 Green Power Generation Call for Tenders (2002/03 GPG CFT).

Future questions may be submitted in writing as directed in the 2002/03 GPG CFT. Those questions will be answered in writing. If a question is relevant to more than one bidder, BC Hydro will post the Q&A to the web site. Those questions will be edited as indicated above as well as to remove any project-specific information. Duplicate questions and answers will not be posted.

Where there is any conflict between the Questions & Answers and the provisions of the 2002/03 GPG CFT, the provisions of the 2002/03 GPG CFT govern. The Questions & Answers do not in any way alter, or otherwise form any part of, or constitute legal advice with respect to the meaning or effect of, the 2002/03 GPG Standard EPA.

Introduction

1. **Will BC Hydro be posting a Word version of the 2002/03 GPG Standard EPA, to make it easier to submit potential revisions?**

   No, BC Hydro will not be posting a Word version of the 2002/03 GPG Standard EPA. The Standard EPA – Proposed Revisions form alleviates the risk inherent in having a number of different "live" Word versions of the EPA in existence.

2. **Will any of the interconnection constrained areas be made public?**

   For this call we will be notifying only those bidders who are in constrained areas. While BC Hydro may publicly release information about all constrained areas in future calls, we must take into account security risks in publicly sharing detailed information about the entire BC Hydro system.

3. **Has BC Hydro determined the exact cap for the 2002/03 GPG program? Will Brilliant Expansion Project's output be excluded from this cap?**

   BC Hydro has committed that, **if** the Brilliant Expansion Project bid is successful in the CFT, we will exclude the output of this project in filling the 800 GWh/year cap for the 2002/03 GPG process. At this time, BC Hydro has not determined if the cap will be increased further.

EPA Overview

4. Could you provide an example of Deliberate Breach?

The term Deliberate Breach is defined in Appendix 1 of the 2002/03 GPG Standard EPA. The best example of Deliberate Breach is turning down the Seller's Plant where that turndown is not authorised under the 2002/03 GPG Standard EPA.

5. Would drought conditions be considered a Force Majeure?

Pursuant to section 10.3 of the 2002/03 GPG Standard EPA, drought conditions that result in a lack of Energy Source would not be a Force Majeure event. If the drought has some other impact such that the Seller is unable to perform its obligations under the 2002/03 GPG Standard EPA, that could be a Force Majeure event.

6. Is it correct that the Seller is required to deliver power on an hourly basis but the delivery requirement for purposes of determining whether Liquidated Damages (LDs) are payable is based on a monthly percentage?

Yes.

7. If you are shut down for an hour or so a day but at the end of the month you are above the 90 % capacity factor, is there any penalty for being shut down on an hourly basis?

LDs are payable for failure to meet the monthly and annual capacity factors of 90% and 80% respectively. That exposure is the Seller's only exposure for damages for non-deliberate delivery failures, whether the result is (i) a shortfall from the required minimum monthly or annual capacity factors, or (ii) a failure to meet the delivery obligation in section 7.2, or (iii) output variations within an hour or output exceeding the permissible range, either of which would violate section 6.3. The exclusivity of LDs for non-deliberate delivery failures is set out in section 12.3. If there are repeated delivery failures or output variations, the Buyer may also be entitled to terminate the 2002/03 GPG Standard EPA. This is set out in the definition of "Seller Default" in Appendix 1.

8. Would logs blocking your intake be considered a deliberate breach?

Generally no. However, if the Seller knows of the logs and deliberately fails to remove them within a reasonable time, that might be a deliberate breach.

9. In discussing the allocation of risk under the 2002/03 GPG Standard EPA you indicated that Sellers are able to control their fuel supply. That is not the case for wave, hydro, solar or wind projects. How is the Seller's lack of control over the fuel supply addressed for these projects?

The Natural Resource Adjustment is intended to address the lack of fuel supply control for those projects. Sellers who elect to have the Natural Resource Adjustment applied to their Bid Price will not be subject to LDs under the 2002/03 GPG Standard EPA where the inability to generate is due solely to lack of the Energy Source.

10. How is the risk of changes in law allocated under the 2002/03 GPG Standard EPA?

The only provisions of the 2002/03 GPG Standard EPA that deal directly with changes in laws are the Hardship Event provisions. A change in laws that constitutes a Hardship Event is a shared risk in the sense that in the case of a Hardship Event the Seller is authorised to shut down without penalty. In that circumstance, the Seller does not get paid, but BC Hydro also does not receive generation, and cannot recover damages from the Seller with respect to that lost generation. Changes in law are also addressed to some extent in the annual increase to the Bid Price based on 50% of the increase in the Consumer Price Index. To the extent that changes in laws impact generally on costs of doing business, this may be expected to be reflected in the Consumer Price Index. Finally, bidders are entitled to bid a competitive price in the 2002/03 GPG CFT process rather than being subject to a single, fixed price. Bidders can make their own assessment of the risks of a change in laws in setting their Bid Price.

11. Does the payment of LDs do away with the requirement to meet the 50 % minimum per month of Contracted Capacity?

The 50 % rule applies only when the bidder is initially establishing its Contracted Capacity. BC Hydro did not want bidders to turn a 10 year contract into what was effectively a 5 year contract by, for example, bidding 10 MW/year for the first 5 years and dropping down to 0.1 MW for the remaining 5 years. So, the 50 % rule is a limitation on the ability to bid a declining Contracted Capacity profile.

12. How do you comply with the 50 % rule where you have very "peaky" projects, with water flows varying widely during the year?

The 50% rule applies only to the average annual Contracted Capacity and not to the monthly profile. In the case of the monthly profile, provided that the monthly amounts average to 100 %, individual months can be as low as zero.

13. How do I reflect planned outages in filling out the Contracted Capacity table?

Generally, it should not be necessary to reflect Planned Outages in filling out the Contracted Capacity table. Hours during which the Seller's Plant is not generating due to a Planned Outage in Non-Winter Months are excluded from the calculation of the Seller's delivery commitment on a monthly basis. Hours during which the Seller's Plant is not generating due to a Planned Outage are included in calculating the Seller's delivery commitment on an annual basis but it was felt that generally

Planned Outages could be taken with the Seller still meeting the 80% annual capacity factor. However, if a bidder is concerned that it cannot meet the 80% capacity factor, then that bidder can bid a lower average annual Contracted Capacity in the year in which that Planned Outage will occur.

14. In the case of an EPA having a term of, for example, 20 years, it could happen that in the later years it might be necessary to take a lengthy planned outage to do a major rebuild of the unit – a generator rewind or something of that nature. It appears that there is nothing in the 2002/03 GPG Standard EPA to specifically allow for that, other than the normal planned outage provisions. Is that correct?

Yes, that is correct. However, it must be remembered that the 20% "cushion" before LDs are triggered on an annual basis, allows for 73 days – or almost two and a half months – of downtime. In fact, the downtime could be longer if the plant had generated above the Contracted Capacity level (i.e., up to 110%) for much of the year.

In addition, if a bidder anticipates that it will be necessary to take the generator out of service for a prolonged planned outage after a given number of years of operation, the bidder could bid a lower Contracted Capacity in a particular year as suggested in Q #13 above.

15. Why is the CFT Adjusted Bid Price used for calculating LDs, rather than the Bid Price?

The CFT Adjusted Bid Price is used to ensure that items such as the "green premium" and the GHG intensity adjustment are deducted from the Bid Price because those adjustments are not included in the Mid-C Price. It is necessary to ensure that the two numbers being compared for purposes of calculating the LDs are comparable numbers.

16. Why will BC Hydro only purchase a maximum of 110% of the Contracted Capacity?

The Seller has no obligation to deliver any power in excess of the Contracted Capacity. Therefore, any power in excess of the Contracted Capacity is "non-firm" power. While BC Hydro has allowed a 10% excess at full price, BC Hydro is generally not prepared to pay the same price for "non-firm" power that it is prepared to pay for the Contracted Capacity that the Seller is legally required to deliver and which is therefore as firm as the Energy Source will permit.

17. Why are the Bulk Location, System and Area Location Adjustments taken into account in calculating LDs?

Those adjustments represent the financial impact on BC Hydro of moving the electricity delivered by the Seller from the Point of Delivery to the Lower Mainland.

The LDs calculation compares the “delivered cost” of the Seller’s electricity to the “delivered cost” of Mid-C power.

18. What amendments can we make to the Contracted Capacity profile between 11 June and 29 August?

You can make further amendments to the Contracted Capacity profile between 11 June and 29 August, but those amendments may result in the Tender being disqualified or in Bid Price Adjustments being recalculated. The rules are set out in the 2002/03 GPG CFT document.

19. Will a bidder that submits an amended Contracted Capacity profile on 29 August be told that the amendment will be rejected so that the bidder can revert to the original profile?

No. No indication of the status of Tenders will be given prior to 29 September 2003. No amendments to a Tender will be accepted after 29 August 2003.

20. During the presentation you indicated that the deadline for submitting suggested revisions to the 2002/03 GPG Standard EPA is now 11 June rather than 20 June as indicated in the original schedule in the 2002/03 GPG CFT. Is that correct?

Yes. The date has been moved forward to coincide with the date for submitting Project Changes for review as the proposed revisions to the 2002/03 GPG Standard EPA may be related to proposed Project Changes.

21. What is the cumulative total percentage of the securities and the liabilities relative to anticipated project income?

The answer to this question will depend on each project’s Contracted Capacity. The Development Security is determined by multiplying the maximum annual average Contracted Capacity (Part I of Appendix 2) by $20,000. For a project with a maximum annual average Contracted Capacity of 5 MWh/h, the Development Security will be $100,000. Assuming that the monthly profile is “flat” (i.e., the Seller has contracted to deliver 100% of the Contracted Capacity in each month of the year), and assuming that the Seller’s Plant operates at a capacity factor of 80% in each month and that the Bid Price is $55/MWh, the annual revenue would be $1,927,000. The Development Security therefore represents 5% of a single year’s revenue from the Seller’s Plant. The Operating Security is calculated annually and is an amount equal to $2,000 multiplied by the annual average Contracted Capacity for the year in which the calculation is occurring multiplied by the number of years remaining in the Term of the EPA. Again, assuming an annual average Contracted Capacity of

5MWh/h in each year in a 20 year Term, the Operating Security at COD would be $200,000. This amount represents approximately 10% of a single year's revenue but less than 1% of the total revenues over the Term of the EPA. The Development Security and the Operating Security are not cumulative because the Development Security is released once COD is achieved. The Development Security must be in the form of a letter of credit. The Operating Security must be in the form of a letter of credit or a guarantee from a creditworthy entity. The annual cost of posting a letter of credit is much less than the amount of the credit thereby reducing the cost of the security to a much lower percentage of the projected annual revenue.

The monthly and annual LDs are capped (except in the case of Deliberate Breach) at $1,000/MWh/h based on the Contracted Capacity for the relevant month and $3,000/MWh/h of annual average Contracted Capacity for the relevant year respectively. Again, using the same assumed Contracted Capacity, operating scenario and Bid Price described above, the plant would be subject to LDs in each month for a maximum LD exposure of $60,000 for the year. This represents 3% of the annual revenues.

22. Under what circumstances can the 2002/03 GPG Standard EPA be terminated for "regulatory intervention" after the end of the Initial Period?

Under sections 15.1(d) and 15.2(c) of the 2002/03 GPG Standard EPA, the Buyer and the Seller respectively have rights to terminate the EPA after the Initial Period where: (i) the Seller becomes subject to regulation as a public utility with respect to the Seller's Plant, the sale of Electricity under the EPA or the performance of the Seller's obligations under the EPA and (ii) such regulation results in the benefit of the EPA to the Buyer or the Seller (whichever party is seeking to invoke the termination right), being materially and adversely affected. Generally, these provisions are intended to apply where the Seller has not taken, or omitted to take, any action that caused the Seller to become regulated as a public utility. Under section 15.1, the Buyer can also terminate the EPA for Seller Default. A Seller Default would include a breach by the Seller of section 7.4 which prohibits the Seller from taking, or omitting to take, any action that would cause the Seller to cease to be exempt from regulation as a public utility with respect to the Seller's Plant, the sale of Electricity under the EPA or the performance of the Seller's obligations under the EPA or that would cause the owner of the transmission line from the Seller's Plant to the POD to be regulated as a public utility where, in either case, that designation as a public utility could reasonably be expected to have an adverse effect on the Buyer.

23. In the case of a biomass plant what happens if fuel becomes so expensive that it isn't economically viable to run the plant?

One of the defined Hardship Events is a lack of availability, or an increase in price, of a thermal energy source. In those circumstances if the result of that lack of availability or price increase is a severe economic impact that affects the viability of the Seller's Plant, that is a Hardship Event, leading to a reduction in the Seller's delivery commitment. However, there are a number of preconditions to relief in the case of a Hardship Event including the fact that the Seller cannot claim relief for a Hardship Event based on lack of availability, or an increase in price, of a thermal energy source prior to the third anniversary of COD.

24. **It appears that the revenue lost by taking the Natural Resource Adjustment is more significant than the LDs. Is that correct?**

    Likely yes. However, that is not the only consideration in determining whether or not to take the Natural Resource Adjustment. Other issues that bidders may wish to consider are BC Hydro's termination rights if the Seller does not meet its monthly and annual delivery commitments and the limits on the amount of electricity that BC Hydro will purchase for those projects that do not take the Natural Resource Adjustment.

25. **In light of the fact that BC Hydro will not purchase more than 110% of Contracted Capacity for those projects that do not take the Natural Resource Adjustment, is it not the case that all wind or water projects in the province will be forced to take the Natural Resource Adjustment?**

    That may be the case and if that is the case, that is the correct result. The Natural Resource Adjustment is an adjustment that is intended to reflect the fact that some green power is less firm than other green power. The Natural Resource Adjustment is intended to ensure that those bidders who can deliver green power with a greater degree of firmness have an opportunity to submit a higher Bid Price for that power as that power has a greater value than power which is less firm.

26. **I can not help but notice that the Natural Resource Adjustment and Green Criteria Adjustment are both $5.00. Is BC Hydro saying being firm has the same value as being green?**

    Each bid adjustment for the 2002/03 GPG Call was arrived at independently. These values reflect the bid adjustments that will be made for each of these factors for this call and are not intended to reflect the relative value of firm energy to green energy.

GHG Intensity

27. Who owns the rights and benefits associated with any GHG reductions resulting from a project for which a Tender is submitted in the 2002/03 GPG CFT process?

As defined in Appendix 1 of the EPA, BC Hydro owns the Off-Site Emission Reduction Rights associated with any actual or assumed displacement of emissions at generating facilities owned by BC Hydro or its affiliates as a result of the purchase of electricity by BC Hydro from a project for which a Tender is submitted in the 2002/03 GPG CFT process. If there are any other GHG reductions associated with the project (i.e., on-site emission reduction rights), the benefits arising from those reductions are owned by the project proponent.

Contracted Capacity

28. With respect to part (i) of the definition of Seller Default, are you looking at 24 months on a sliding basis or, say over 10 years, would you pick 24 months out of that 10- year period?

In part (i) of the definition of Seller Default, the phrase “6 or more months in any 24 month period” refers to a 24 consecutive month block of time. Therefore, the 24 months is on a “sliding” basis, in that adding a month at the end of the block would necessitate dropping a month at the beginning of the block in order to maintain 24 consecutive months. For example, the 24 month block of time could encompass March 2008 to February 2010 (inclusive), or “slide” forward to encompass April 2008 to March 2010 (inclusive), and so on.

29. In filling in the Contracted Capacity Tables in Part I and II of Attachment C, am I correct in assuming that I don’t have to specify the month during which I intend to have a Planned Outage because the Planned Outage Hours are deducted in the Monthly Contracted Electricity calculation?

Yes. In completing the Contracted Capacity tables, it generally should not be necessary to reduce your expected output for sale to BC Hydro to account for Planned Outages because the Planned Outage Hours in Non-Winter Months ***are not*** included in calculating the Monthly Contracted Electricity (refer to Item 2 of Appendix 4 – Liquidated Damages (LDs) in the EPA). However, all Planned Outage Hours ***are*** included in calculating Annual Contracted Electricity (refer to Item 3 of Appendix 4 – LDs in the EPA), which is why the trigger for Annual Capacity Factor LDs is set at 80% of Annual Contracted Capacity, while the trigger for Monthly Capacity Factor LDs is set at 90% of Monthly Contracted Capacity. The extra 10% is intended to allow for output shortfalls resulting from Planned Outages. However, if you believe that the 20% annual shortfall allowance is not sufficient to account for the number of Planned Outage Hours required at your plant, you may want to account for the expected reduced output in the Tables in Part I and/or Part II of Attachment C of the CFT.

30. When does the one time opportunity occur to increase your average annual Contracted Capacity by as much as 20%, and to also revise your monthly profile (provided that it still complies with the rule of averaging to 100% when weighted by the days of the month?

As stated in section 3.5 of the 2002/03 GPG Standard EPA, notice to the Buyer regarding the one- time opportunity to increase the Seller’s Contracted Capacity by as much as 20%, and/or amend the monthly profile, must be received before the earlier of (i) the fulfilment or waiver of the conditions in section 3.1, and (ii) the Initial Period Expiry Date, which is defined in item (tt) of Appendix 1 of the EPA as the date that is 180 days after the commencement of the Term as extended pursuant to section 3.3, or as further extended by written agreement between the Parties.

31. **My understanding is that bidders have an opportunity to revise their energy profiles - a 12 × 24 output matrix - during and up to the end of the Initial Period. Is that correct?**

Bidders have an opportunity to increase their Contracted Capacity (Part I of Appendix 2 in the 2002/03 GPG Standard EPA) by a percentage not exceeding 20%, and/or amend their monthly profile (Part II of Appendix 2 in the EPA), provided the numbers in Part II average to 100% when weighted by the number of days in each month. Neither Table in Part I or Part II in Appendix 2 of the EPA is a 12 × 24 matrix.

32. **In your "small hydro example," the entries in Part II of Attachment C are 168.76%, 194.65% and 194.64% respectively for May, June and July. For these months, and any other months in Part II of Attachment C that have numbers in excess of 110%, will the proponent be triggering LDs or be in breach of section 6.3 – Standard of Operation?**

No. First, LDs and section 6.3 - Standard of Operation are based on actual metered output and how that output relates to your contractual obligation (i.e., Contracted Capacity and the delivery of a "consistent amount of electricity" as per section 6.3). Secondly, LDs are not triggered for overproduction; they are only triggered for underproduction. In order to avoid paying Monthly LDs, you must deliver at least 90% of your Monthly Contracted Capacity. In order to avoid being in breach of section 6.3, you must make commercially reasonable efforts to produce a consistent amount of Electricity within each hour and, on an instantaneous basis, deliver an amount of Eligible Electricity of not more than 110% of CC (or 110% of Plant Capacity if the Natural Resource Adjustment has been elected and the Seller is selling the full output to BC Hydro), and not less than 90% of CC.

33. **So in order to avoid 1) triggering LDs, 2) overproducing and not being paid for the output and/or 3) being in breach of the 2002/03 GPG Standard EPA under section 6.3 – Standard of Operation, we simply need to deliver output within a band defined by ± 10% of CC. Is this correct?**

Yes.

34. **In the case of a hydro project, where the Natural Resource Adjustment has been elected and where the output in winter months (e.g., January) is, on average, a small proportion of the average annual Contracted Capacity (e.g., 4%) but this output comes in the form of 3 or 4 flood days where the output is close to 110% of Plant Capacity, will the Seller be paid for this output?**

Yes. If the Seller elected to take the Natural Resource Adjustment in the CFT process and if the Seller is selling the full output from the Seller's Plant to BC Hydro, BC Hydro will take and pay for up to 110% of Plant Capacity, which is the aggregate nameplate capacity of all electrical generators in the Seller's Plant.

35. So, if the Seller has elected to take the Natural Resource Adjustment, why wouldn't the Seller simply enter 100% for every month in Part II of Attachment C in order to gain the flexibility of having a higher limit on the amount of electricity which BC Hydro will pay for?

First, bidders must follow the instructions in the Tender Forms. Also, in section 18.1 of the EPA (as amended by Appendix 11), the bidders make representations and warranties about the Contracted Capacity (CC) they have specified. If bidders make false representations and warranties, this would constitute Seller Default; BC Hydro could terminate the EPA, and the Seller would be liable for a termination payment, depending on the market price at the time of termination. Second, a higher CC means potentially higher LDs and a higher probability of triggering those LDs. In a case where the NRA is elected but LDs still apply (e.g., a forced outage for reasons other than a lack of energy source), if the CC was set unreasonably high in order to capture the upside of selling more to BC Hydro, the LDs would also be higher than they would be if the CC had been set in accordance with the CFT instructions, based on "the Energy Source expected to be available in the average year" (see page 28 of the CFT).

36. In your Table for high load hours and low load hours (Appendix 3 of the 2002/03 GPG Standard EPA), you do not go to two decimal places. However, you have asked that bidders use two decimal places when completing the Tender Forms. Will BC Hydro consider using two decimal places for the delivery Time Adjustment Table based on the fact that, when weighted by the number of hours in each month, the rounding short changes the Seller by approximately 30 hours per year?

BC Hydro is currently reviewing the Table for high load hours and low load hours. If it is determined that there is rounding error as described the table will be corrected and issued as an EPA amendment.

37. Hypothetically, if the Seller triggers LDs for a particular month, how does BC Hydro determine if the shortfall was during high load hours or low load hours?

High load hours (HLH) and low load hours (LLH) relate to payment. LDs are based on the aggregate Eligible Electricity for a particular month, or for a particular year. LDs are not based on the time of day at which the energy was delivered. For purposes of calculating the LDs the formula uses the hourly weighed average of the Mid-C Index prices in the applicable month based on the percentage of On-Peak hours and Off-Peak hours and Sunday and NERC holiday hours in the month regardless of when the actual delivery shortfall occurred. The intent of the delivery time adjustment is to send a pricing signal to the Seller regarding the preferred time for maintenance. If the Seller must take the plant off-line due to a forced outage or for some other reason, the Seller, wherever possible, should schedule this outage at a less economically favourable time of the day, day of the week and/or month of the year based on the payment incentive outlined in section 3.3 of Appendix 3 of the EPA.

38. In terms of the Tender Form instruction on page 27 of the CFT, what happens if the minimum average annual Contracted Capacity stated in Part I of Attachment C *is* less than 50% of the maximum average annual Contracted Capacity specified in Part I of Attachment C?

In its evaluation of the Tender, BC Hydro would determine that Attachment C has not been filled out in conformance with the CFT instructions and would reject the Tender at Step 1 of the Award Process based on material non-conformity of the Tender Forms.

39. In your "small hydro example," you have a CC of 59.94% of 10.17 MWh/h for the month of January. Am I correct in assuming that LDs will apply in this case, because the percentage stated in Part II of Attachment C is below 90%?

No. The 90% applies to the Contracted Capacity for the month, not to the percentages in Part II of Attachment C. Monthly LDs are triggered if your Delivered Electricity is less than 90% of your Monthly Contracted Electricity (see section 2 of Appendix 4 in the EPA). In the case of the example cited, assuming that there are no Force Majeure Hours, Transmission Constraint Hours and Planned Outage Hours, the Monthly Contracted Electricity would be: 59.94% × 10.17 MWh/h × 31 days × 24 h/day = 4535.00 MWh for the month of January. If your plant output was less than 90% × 4535.00 MWh = 4081.50 MWh during January, you would be liable to pay LDs.

40. If we are only requesting a 10-year contract, do we just strike out the last 10 years in Part I of Attachment C in the Tender Forms?

In the case where you are bidding a 10-year contract, you must simply leave the last 10 rows blank in Part I of Attachment C. Do not strike out the extra years that do not apply to your contract.

41. Just to clarify, in submitting the Contracted Capacity to BC Hydro, the idea is for the bidders to only submit Attachment C of the CFT (which becomes Appendix 2 of the EPA), and not to submit supporting information such as calculation worksheets?

That is correct.

42. In your "small hydro example," what would be the Development Security and Operating Security for this project?

Section 13.1 of the 2002/03 GPG Standard EPA states that the Development Security is calculated by multiplying the maximum average annual Contracted Capacity shown in Part I of Appendix 2 by \$20,000/MWh/h. In the "small hydro example" the average annual Contracted Capacity is 10.17 MWh/h for all 15 years post COD. Therefore, the Development Security is \$20,000 /MWh/h × 10.17 MWh/h = \$203,400. Section 13.4 of the EPA states that the Operating Security, as determined on each anniversary of COD, is \$2,000/MWh/h times the average annual Contracted Capacity as shown in Part I of Appendix 2 for the year commencing at the date of the calculation times the number of years remaining in the Term. In the "small hydro example," the Operating Security at COD is \$2,000/MWh/h × 10.17 MWh/h × 15 = \$305,100.

43. Why is the Development Security \$203,400 for your "small hydro example," which has a nameplate capacity of 20MW, while in the earlier presentation on the EPA Overview, a plant with a Contracted Capacity of 5 MWh/h had a Development Security of \$100,000? Why does a project that is 4 times larger only have a Development Security that is twice as large?

In the case of the "small hydro example," the nameplate capacity was 20 MW, but the average annual Contracted Capacity was 10.17 MWh/h. In the earlier example, the Contracted Capacity was 5 MWh/h, and the nameplate capacity was not specified. The Contracted Capacity in the small hydro example is roughly twice as much as the CC in the earlier example, so the Development Security is correspondingly twice as big.

44. In calculating the energy output for each project for the purposes of accepting projects up to the desired energy cap for this Call, does BC Hydro use the average annual Contracted Capacity for the first year, or does BC Hydro take the average of the average annual Contracted Capacity over the Term?

As stated on page 19 of the CFT, BC Hydro will determine when the energy limit has been reached by multiplying 8760 by the average annual Contracted Capacity for Year 1, as stated in Part I of Attachment C to the Tender Forms for each bidder as that bidder is awarded an EPA.

45. I'm curious about the pricing signal. BC Hydro has a high load hour and a low load hour pricing signal, yet contractually BC Hydro wants a flat delivery. I would have thought that if BC Hydro is providing a pricing signal, BC Hydro would want more energy at certain times and less at other times, and would want the Seller's output to respond to that pricing signal.

In this Call, BC Hydro's desire for firm, dependable power supersedes our desire to have someone shape to the high load hours and low load hours, as defined in

Appendix 1 of the 2002/03 GPG Standard EPA. The structure of this EPA is not designed to accommodate firm hour by hour electricity supply or significant shaping ability by the Seller. In addition, the HLH and LLH defined in Appendix 1 are based on a prediction of average demand, and do not necessarily match actual demand. Therefore, HLH and LLH should be used as a pricing signal for planned or forced outages. Many projects that meet the green criteria have a limited ability to shape on a daily basis or seasonal basis. Therefore, the HLH and LLH were designed to help the Seller "tweak" their operation and maintenance scheduling, as opposed to a full fledged synchronisation of plant output to the HLH and LLH schedule.

46. It appears that the forgone revenue of not being able to produce at your full Contracted Capacity provides enough of an incentive to make best efforts to maximise your Eligible Electricity output without having to have the additional burden of LDs. In addition, these LDs have been capped, which effectively makes them small compared to the forgone revenue suffered as a result of reduced output. The cap on the LDs also provides a potential financial incentive to have a high Contracted Capacity in order to take advantage of overproduction, because the financial downside to underproduction is relatively small. Can you please comment?

There is a natural incentive to produce and sell electricity to BC Hydro up to a maximum of 110% of CC (or 110% of Plant Capacity, if the NRA is elected and the full output of the Seller's Plant is being sold to BC Hydro), provided that the spot market prices for energy are less than the EPA price. However, if the spot market prices for energy are higher than the EPA price, there is a disincentive to deliver output to BC Hydro. The limitation (cap) on the amount of damages for non-delivery does not apply in the case of Deliberate Breach. Damages payable to BC Hydro by the Seller for non-delivery exist regardless of whether or not the method of calculating those damages has or has not been explicitly stated in the contract as LDs.

In response to the observation concerning the effect of the LD caps on the Contracted Capacity, it is important to understand that bidders <u>must</u> follow the instructions in the Tender forms. Under section 18.1 of the EPA (as amended by Appendix 11), bidders are required to make representations and warranties about the Contracted Capacity they have specified. If bidders make false representations and warranties, this would constitute Seller Default; BC Hydro could terminate the EPA and the Seller would be liable for a termination payment. In addition, if a bidder who has not elected the NRA is considering bidding in a higher average annual Contracted Capacity in order to take advantage of times when there is higher flow, aside from making false representations and warranties, that bidder may also run the risk of delivering less than 90% of the Contracted Capacity for more than 6 months in a 24-month period, or less than 80% of average annual Contracted Capacity for 3 consecutive years, at which point the bidder's EPA would be subject to termination (refer to "Seller Default" in Appendix 1 of the EPA).

Implications in the EPA

47. Take the case of a wind or water project in which the Average Annual Contracted Capacity (AACC) is set at 10 MWh/h and the monthly profile varies from about 60 % to about 200% of the AACC during the course of the year, and the Seller has installed a 20 MW capacity generator. If unexpectedly high winds or water flows happened for a few days, so that electricity was being generated at, say, 20 MWh for several hours or days, is it the case that BC Hydro, as Buyer, would only have to pay for electricity up to 110% of the Contracted Capacity, and would get "free" electricity for generation above that level?

The electricity that BC Hydro would have to take and pay for in a case such as this would depend on whether the Natural Resource Adjustment had been selected, and whether the full output of the Seller's Plant was being sold to BC Hydro for the year in question. If the Natural Resource Adjustment had been selected, and the Seller had committed to sell the full output to BC Hydro, then BC Hydro would be obliged to take and pay for electricity generated up to 110% of the Plant Capacity, regardless of what the Contracted Capacity may have been for that month. If the bidder has not selected the Natural Resource Adjustment or if the Natural Resource Adjustment has been selected but the full output is not being sold to BC Hydro under this EPA, then the "Eligible Electricity" in any hour would be a maximum of 110% of the Contracted Capacity applicable for the month in question. Slides 87-90 in the presentation further illustrate the possible outcomes in situations such as these.

48. In a situation where the output of a plant is varying from hour to hour during the course of a month, underproducing in some hours and overproducing in other hours, relative to the Contracted Capacity obligation, wouldn't the Seller be potentially subject to Liquidated Damages (LDs) for the underproduction while not receiving any credit for the hours in which it overproduced?

No, that is not the case. For purposes of determining whether the 90% monthly threshold has been met, and hence whether any LDs would be payable for a shortfall, the plant performance is measured over the course of the whole month. That is, so long as the Seller is using commercially reasonable efforts to operate the plant so as to produce within the 90% to 110% range of the Contracted Capacity on an hourly basis as required by section 6.3 of the 2002/03 GPG Standard EPA, if something happens – e.g., a clogged intake – that causes the Seller to have to scale back output, or even shut down, for an hour or two until the situation is rectified, there is no penalty for that. It is the total Monthly Delivered Electricity (see Appendix 4) from the plant for the month that is taken into account for purposes of LDs determinations.

49. How are forced outages taken into account in the determination of whether or not the 90% monthly and 80% annual delivery thresholds have been met?

In respect of outages, in some cases – depending on the cause – the outage might qualify for relief under the Force Majeure provisions, in which case is would be deducted from the Contracted Capacity obligation before determining whether the 90% monthly threshold had been met. In cases, which don't qualify for Force Majeure relief, the 10% and 20% monthly and annual "cushions" before LDs would become applicable, and are intended to provide sufficient leeway to accommodate these types of situations.

50. Section 7.11 of the 2002/03 GPG Standard EPA requires the Seller to install the revenue meter for the plant as close to the generator terminals as practicable. However the Point of Delivery (POD) – where the plant is connected to the BC Hydro system - could be some distance from the generator, resulting in line losses between the generator and the POD. That hasn't been discussed in any of the examples. How will this be taken into account in the determination of Eligible Electricity? Will some sort of hourly adjustment be made?

Revenue meters currently in use can be calibrated to automatically adjust for such losses. So, the meter will effectively be reading out the electricity that is being delivered at the POD and no separate adjustment will be required.

51. In a situation where the Seller has not elected to take the Natural Resource Adjustment, and a hydro plant is producing at very low levels for much of the month, but then has two or three days of very high water flows and high production, could it happen that the 90% threshold has been met for purposes of determining whether any LDs are payable, but that the Seller wouldn't get paid for most of the electricity generated on those very high production days?

BC Hydro is only obliged to accept up to 110% of the hourly Contracted Capacity in the case where the Natural Resource Adjustment has not been elected. Whether or not the 90% threshold is met or exceeded depends on what the Contracted Capacity is for that month. If the Contracted Capacity was set low enough to begin with, then the 90% threshold may be met, however any deliveries above 110% of the Contracted Capacity would not be purchased by BC Hydro under the terms of the EPA and would not be considered in determining whether the 90% threshold for the month has been met. On the other hand, if the Contracted Capacity was set high enough to begin with, then the 90% threshold may not be met and LDs may apply depending on the pricing at mid-C.

52. Please explain what BC Hydro's obligation would be in a split bid situation in which the Seller hasn't taken the Natural Resource Adjustment.

In this case, BC Hydro is obligated to take and pay for up to 110% of the Contracted Capacity on an hourly basis. It should be noted that this is not 110% of the AACC, but rather 110% of the hourly Contracted Capacity applicable for the particular month based on the monthly profile contained in the Table in Part II of Appendix 2. This obligation is derived from section 7.3 and the definition of "Eligible Electricity" in the EPA, and is also illustrated by slide 90 in the presentation.

53. Could you please clarify the relationship between monthly LDs determinations and annual LDs determinations? I know that any monthly LDs paid are deducted from annual LDs that might be determined to be payable for the year in question, but it seems that the accumulated monthly LDs could exceed the amount of the annual LDs. Is that correct?

Yes, that is correct. Although any monthly LDs paid are deducted from any annual LDs payable, they are determined separately and on a separate basis. Therefore, in a case where monthly LDs of e.g., $5,000 might be payable for, say, 8 months of the year, the accumulated monthly LDs would total $40,000. Then at the end of the year, it could happen that annual LDs of, for example, $20,000 would have been payable – but because the monthly LDs already exceeded this amount, no annual LDs would in fact be payable. This would not, however, limit the accumulated monthly LDs; they would remain at the total of $40,000 paid.

54. In your presentation slide #100, based on the 10.17 MWh/h AACC of the plant in the example, the maximum annual LDs are shown as $30,510, which is $3,000 times 10.17. Shouldn't the maximum annual LDs be $3,000 times 80% of 10.17?

No, the calculation shown is correct. The maximum LD limits provided for in section 12.2 of the EPA are based on the AACC in the case of the annual LDs, or the monthly Contracted Capacity in the case of monthly LDs.

55. In a situation where a plant had a forced outage of say 24 hours or 48 hours, this would mean that the Seller would not deliver electricity during that period and not get paid for it, and this would also get taken into account in the determination of LDs (if any) for the month and year in question. But would that be the sole consequences for not being able to deliver for that period?

Assuming that the outage hasn't occurred as a result of some deliberate act or gross negligence on the Seller's part, there would be no other damages consequences - LDs or otherwise - in that situation. However, please note that, depending on the performance of the Seller's Plant in the current month and in the preceding months and years, an outage such as this could possibly trigger a "Seller Default" - see clauses (i) and (ii) of the definition of that term in Appendix 1 to the EPA.

There are also certain situations where, for example, if the outage was partly a cause of LDs becoming payable for the month or year in question, and this resulted in monthly LDs having become payable in more than 6 months in any 24 month period, or annual LDs having become payable in any 3 consecutive years, as provided in clauses (i) and (ii) of the definition of "Seller Default" in Appendix 1, other consequences could follow.

56. There was some discussion at the GPG Workshop on 30 April about the Brilliant project, indirectly owned by the government, bidding into this CFT. If they do bid, will they have to meet a flat 24-hour load profile required of other bidders?

The same rules will apply to all bidders.

57. In the case of a small hydro plant, because of the variability of the water resource during the course of the year – e.g., between 60% and 200% of the AACC as shown in some of the examples in the presentation slides – the Seller is going to have to size its plant (its nameplate capacity) perhaps as much as 200% over the AACC. This would mean that if the Seller is trying to operate so as to stay within the Contracted Capacity range, there could be periods when there would be the potential to produce greater amounts of electricity, but the Seller would not be able to deliver that greater amount of electricity or receive payment for it. Please comment.

First, although the Seller is required to specify an AACC for inclusion in Table I of Appendix 2 to the EPA, there is the opportunity to shape the monthly profile to be included in Table II so as to match the normal flow profile of the resource. This would enable the monthly Contracted Capacity to match, as closely as possible, the expected peak flows during the year. Second, if the Seller elects to take the Natural Resource Adjustment and commits to sell the full plant output to BC Hydro, the Seller would be entitled to have BC Hydro accept and pay for up to 110% of the Plant Capacity, regardless of what the monthly Contracted Capacity might be at that time.