

## VIGP Benchmark Analysis

This document presents benchmark results for VIGP based on values recommended in the BCUC's September 8, 2003 Decision on the *Vancouver Island Generation Project Application for a Certificate of Public Convenience and Necessity*. Where values are not cited in the Decision, BC Hydro has turned to the CPCN Application, BCTC, or made assumptions that are documented in the input description that begins on the following page.

The "Benchmark – CPCN" results are shown on page 6 of this memo. BC Hydro generated the results using a modified version of the updated Tender Spreadsheet that the QEC used to evaluate the proffered Tenders. The modifications add the functionality necessary to calculate levelized unit energy costs (LUEC). LUEC is BC Hydro's standard metric for energy costs<sup>1</sup>. While LUEC will not be used in the portfolio analysis, BC Hydro has included the metric in the benchmark presentation for the benefit of those parties that are used to evaluating generation options using LUEC.

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<sup>1</sup> LUEC is the present value of the costs of production divided by the present value of the energy produced.

## Tender Spreadsheet Inputs – VIGP Benchmark – CPCN

### Term Information

| <i>Item</i>      | <i>Value</i> | <i>Source / Note</i>           |
|------------------|--------------|--------------------------------|
| EPA Term (years) | 25           | Tender length of CFT analysis. |

### Capacity

| <i>Item</i>                                       | <i>Value</i> | <i>Source / Note</i>   |
|---|--------------|--|
| Bid Capacity (MW)                                 | 265          | Contracted capacity at COD in the first year.  |
| Capacity Degradation Factor (% over the EPA Term) | 0%           | Degradation not included in the CPCN Application   |
| Capacity Conversion Table (%)                     | 0            | Absent any information on performance variations with temperature/humidity in the Decision, we have assumed zeros for all table entries. |

### Capital and Operation & Maintenance Charges

| <i>Item</i>    | <i>Value</i> | <i>Source / Note</i>  |
|----------------|--------------|---|
| CC (\$/MW/mo)  | \$9,920      | (1) Average of high and low levelized charge from pg. 35 of the Decision (\$30M/yr) divided by 265MW and 12 months. Escalated by 1.021 <sup>2</sup> to convert to 2004 dollars, plus (2) \$2.85M in incremental direct assignment network connection costs from BCTC (\$6.3M of connection costs are already in the cost estimate from (1)), converted to an annual levelized charge using an 8% discount rate and 25 year term, divided by 265MW and 12 months. Escalated by 1.021 to convert to 2004 dollars. |
| OMC (\$/MW/mo) | \$4,442      | VIGP OMA Costs from Table 5.2 of the Decision excluding variable costs (\$16 M/yr) divided by 265MW and 12 months. Deflated by 1.021 <sup>6</sup> to convert to 2004 dollars.   |
| OMC escalation | 2.1%/yr      | Assume a fixed 2.1% per year (the CFT's forecast rate of inflation) which is consistent with the inflation rate stated on page 16 of the Decision.  |

### Energy Charge

| <i>Item</i>            | <i>Value</i> | <i>Source / Note</i>  |
|------------------------|--------------|---|
| Energy Charge (\$/MWh) | \$4.19       | <p>1) \$0.438 from \$1M variable OMA cost from Table 5.2 of the Decision, divided by 2025 GWh/yr output (from the June CPCN update). Deflated by 1.021<sup>6</sup> to convert to 2004 dollars. Plus...</p> <p>2) \$3.745 from \$3.60/MWh for GHG escalated by 1.021<sup>2</sup>.</p> <p>Does not include firm gas transportation costs as those demand-related costs should not affect dispatch decisions, and are added ex-post in the portfolio analysis stage.</p> |
| EC escalation          | 2.1%/yr      | Assume a fixed 2.1% per year (the CFT's forecast rate of inflation) which is consistent with the inflation rate stated on page 16 of the Decision.  |

### Tolling Tender

| <i>Item</i>   | <i>Value</i> | <i>Source / Note</i>   |
|---|--------------|--|
| Tolling Choice  | Full Tolling |  |
| Guaranteed Heat Rate at COD - Baseload (GJ/GWh)         | 7,308        | Average net heat rate from the CPCN Application  |
| Guaranteed Heat Rate at COD - Minimum Turndown (GJ/GWh) | 8,039        | 10% performance penalty assumed for operation at Minimum Turndown.   |
| Heat Rate Degradation Factor (%)                        | 0%           | Degradation not included in the CPCN Application   |
| Heat Rate Conversion Table (%)                          | 0%           | Absent any information on performance variations with temperature/humidity in the Decision, we have assumed zeros for all table entries. |
| Motor Fuel Tax Rate                                     | 7%           | Decision page 81.  |
| Gas compression fuel and losses                         | 4.97%        | BC Hydro's estimate based on discussions with Terasen.   |

## Tender Operations

| <i>Item</i>  | <i>Value</i>                          | <i>Source / Note</i>   |
|--|---------------------------------------|--|
| Maximum Starts per Year (MSY)(Integers)  | Hot: 50<br>Warm: 100<br>Cold: 100     | Assumed values sufficient to assure that the Tender is not forced to run. (Start up table contains placeholder values only)  |
| Start Up Cost (\$000/start)  | Hot: 1<br>Warm: 2<br>Cold: 5          | Assumed values.  |
| Start Up Cost Escalation   | 2.1%/yr                               | Assume a fixed 2.1% per year (the CFT's forecast rate of inflation) which is consistent with the inflation rate stated on page 16 of the Decision.   |
| Start Up Fuel per start (GJ/start)   | Hot: 2000<br>Warm: 4000<br>Cold: 8000 | Based on an 8,000 GJ/GWh heat rate, 265MW of capacity, and the following hours of operation by type of start (Hot: 1, Warm: 2, and Cold: 4). Results rounded to the nearest 1,000. Using average degraded capacity results in the same rounded values. |
| Ramp up Time (Minutes)   | Hot: 90<br>Warm: 180<br>Cold: 360     | Assumed values.  |
| Must Run?  | Dispatchable                          | Plant not subject to must run limitations in any month.  |
| Scheduled Planned Outage Allowance Hours – Non-Major Maintenance Years (Hours /Year) | 150                                   | Assumed values.  |
| Scheduled Planned Outage Allowance Hours – Major Maintenance Years (Hours/Year)      | 600                                   | Assumed values.  |
| Interval for Major Maintenance   | Fixed Years                           | Equivalent Operating hours do not apply.   |
| Interval for Major Maintenance (Fixed Years)   | 5 Years                               | Assumed value consistent with assumption used for Calpine degradation calculations.  |

|                      |       |   |
|----------------------|-------|---|
| SEC-Defined peaker   | FALSE | Plant subject to minimum turndown limits.                                     |
| Minimum Turndown (%) | 60%   | Assumed value, based on air emission problems at low minimum turndown levels. |

**VIGP Benchmark – CPCN Results  
(2006 beginning of year dollars)**

| <b>Scenario</b>                         | <b>EIA-Full</b> | <b>EIA-Partial</b> | <b>Average</b> |
|---|-----------------|--------------------|----------------|
| Capacity Charges NPV (\$000)            | 314,415         | 314,415            | 314,415        |
| Fixed O&M Charges NPV (\$000)           | 179,513         | 179,513            | 179,513        |
| Capacity and O&M Cost NPV (\$000)       | 493,928         | 493,928            | 493,928        |
| Market Value of Energy NPV(\$000s)      | 1,317,276       | 969,047            | 1,143,162      |
| Variable Costs of Dispatch (NPV\$000s)  | 1,073,237       | 893,573            | 983,405        |
| Energy Margin NPV(\$000)                | 244,039         | 75,475             | 159,757        |
| Startup Cost NPV (\$000)                | 24,493          | 24,493             | 24,493         |
| Net Tender Cost NPV (\$000)             | 274,382         | 442,947            | 358,665        |
| Average Annual Dispatch GWh             | 2,003           | 1,699              | 1,851          |
| Capacity Factor over Term               | 86%             | 73%                | 80%            |
| Total Tender Cost NPV (Not Net) (\$000) | 1,591,658       | 1,411,994          | 1,501,826      |
| NPV (6%) Dispatch MWh                   | 24,463,144      | 20,731,886         | 22,597,515     |
| <b>Levelized Cost (\$/MWh)</b>          | <b>70.6</b>     | <b>74.6</b>        | <b>72.4</b>    |

*Note: The original “BCUC” gas and market forecast was only to the year 2022. To make the “BCUC” forecast consistent with the EIA-Full and EIA-Partial forecasts, the years 2023 through 2025 were extrapolated using a trend of the last five years in the BCUC forecast.*

The NPV (6%) Dispatch MWh and Levelized cost are not part of the distributed Tender spreadsheet. The Levelized Unit Energy Cost equals (Capacity and O&M Cost NPV + Variable Costs of Dispatch NPV + Start up Cost NPV) \*1000 / NPV (6%) Dispatch MWh. This is the standard BC Hydro calculation of a levelized cost per MWh. Note that the MWh are discounted using 6% real discount rate<sup>2</sup>), rather than the 8% WACC (a nominal discount rate).

<sup>2</sup> Precise value is calculated using the following formula:  $(1+8\%)/(1+2.1\%) - 1$ .