26.0 Reference: CFT Report, p. 12

1.26.1 Further to page 12 of the CFT Report, please provide a schedule that shows the Reference Case gas forecast that the Energy Information Administration ("EIA") issued in January 2004, and the forecast converted to Canadian dollars per gigajoule at Huntingdon, expressed in both then-current and real dollars. Further to the notes with Table 6 on page 18 and Table 8 on page 23 of the CFT Report, what is the reference date for the real dollar prices and net present values in the CFT Report?

RESPONSE:

Please see Table IR 1.26.1. The NPV values expressed in the CFT report and within the QEM are expressed in 2006 dollars.

Table IR 1.26.1 - EIA Reference Case Forecasts in $CAD/GJ

Year	EIA 2004 Reference Case - Henry Hub				EIA 2004 Reference Case - Sumas			
	Real 2003 USD/MMBtu	Nominal USD/MMBtu	Real 2003 CAD/GJ	Nominal CAD/GJ	Real 2003 USD/MMBtu	Nominal USD/MMBtu	Real 2003 CAD/GJ	Nominal CAD/GJ
2007	3.70	4.02	4.55	4.94	3.36	3.65	4.13	4.48
2008	3.81	4.23	4.69	5.20	3.47	3.85	4.26	4.73
2009	3.64	4.12	4.47	5.07	3.29	3.73	4.05	4.58
2010	3.57	4.13	4.39	5.08	3.23	3.73	3.97	4.59
2011	3.74	4.41	4.59	5.42	3.39	4.00	4.16	4.91
2012	3.92	4.73	4.82	5.81	3.57	4.31	4.39	5.29
2013	4.10	5.04	5.04	6.20	3.75	4.61	4.61	5.67
2014	4.18	5.25	5.14	6.45	3.83	4.81	4.71	5.91
2015	4.36	5.59	5.35	6.87	4.01	5.14	4.92	6.32
2016	4.39	5.75	5.39	7.06	4.04	5.29	4.96	6.50
2017	4.40	5.88	5.40	7.23	4.05	5.41	4.97	6.65
2018	4.34	5.92	5.33	7.28	3.99	5.44	4.90	6.69
2019	4.29	5.98	5.28	7.35	3.94	5.50	4.85	6.75
2020	4.45	6.33	5.46	7.77	4.10	5.83	5.03	7.16
2021	4.61	6.70	5.67	8.24	4.26	6.20	5.24	7.62
2022	4.58	6.80	5.63	8.36	4.23	6.28	5.20	7.72
2023	4.59	6.95	5.64	8.54	4.24	6.42	5.21	7.89
2024	4.58	7.08	5.63	8.70	4.23	6.54	5.20	8.04
2025	4.57	7.21	5.61	8.86	4.22	6.66	5.18	8.18

26.0 Reference: CFT Report, p. 12

1.26.2 Please describe the reference location for the EIA forecast and identify all assumptions and factors that were used to convert the forecast to Huntingdon prices in then-current and real Canadian dollars per gigajoule.

RESPONSE:

The reference location for the EIA Reference forecast is the US - Wellhead. The closest relevant trading hub for CFT purposes is at Sumas/Huntingdon, Washington. Accordingly, the gas prices in the forecast are first adjusted to account for the basis differential between the EIA forecast, and then for Henry Hub and Sumas. The Henry Hub-Sumas differential is provided by Confer Consulting Ltd. This value is based on an analysis of past and forecast transportation costs between North American gas market hubs.

BC Hydro converts the EIA Average Lower 48 Wellhead Price forecast in real U.S. dollars to the Gas Price Forecast (as defined in the QEM) in nominal Canadian dollars. The conversion process is as follows:

1. **Obtain the EIA Reference Case Forecast from the website: http://www.eia.doe.gov/oiaf/archive/aeo04/aeoref_tab.html. BC Hydro used the Average Lower 48 Wellhead Price from row 10 from the Excel spreadsheet version of Table 14.**
2. **Divide by 1.027 to convert from thousands of cubic feet (MCF) to MMBtu.**
3. **Adjust pricing point from Average Lower 48 Wellhead Price to Henry Hub, Louisiana using basis differential values provided by Confer Consulting Ltd.**
4. **Inflate 2002 dollars to 2003 dollars using inflation assumption.**
5. **Apply basis differential forecast between Henry Hub and Sumas using basis differential values provided by Confer Consulting Ltd.**
6. **Apply monthly shaping factors to convert annual prices to monthly prices.**
7. **Apply inflation rate to convert real dollars to nominal dollars.**
8. **Apply currency exchange rate to convert from U.S. to Canadian dollars.**

The conversion adjustments used in steps 3, 5 and 6 have been provided to the Commission in confidence due to the confidential nature of such information.

For the period 2007 to 2031, BC Hydro assumes an inflation rate of 2.1% per year and a constant exchange rate for the Canadian dollar of U.S.$0.771.

26.0 Reference: CFT Report, p. 12

1.26.3 Please provide a similar schedule for the EIA High Case gas forecast issued in January 2004, and the corresponding then-current and real Huntingdon price forecasts in Canadian dollars per gigajoule.

RESPONSE:

The High Gas Case was not used in the final Quantitative Evaluation. This forecast was provided to the Commission on 22 December 2003 in the prototype evaluation spreadsheets. See the Tendersheet, Tab: "Market".

This forecast was not generated by the EIA or any other forecasting agency. This forecast was created by BC Hydro, and was simply based on the then-current 12-month historical average of Henry Hub spot gas prices.

The determination of the final price forecasts used in the QEM is explained in the response to BCUC IR 1.13.1.

26.0 Reference: CFT Report, p. 12

1.26.4 When does BC Hydro expect that the next EIA gas price forecast will be released?

RESPONSE:

The Energy Information Administration website indicates that its full update of the Annual Energy Outlook, with updated gas price forecast, will be released in January 2005.

26.0 Reference: CFT Report, p. 12

1.26.5 Please provide a schedule showing the most current gas price forecast by Gilbert Laustsen Jung Associates Ltd. ("GLJA") and the forecast expressed in then-current and real Canadian dollars per gigajoule at Huntingdon, identifying all assumptions and factors used to generate the schedule.

RESPONSE:

The price forecast in annual figures is available free of charge on the GLJA website. Access to the forecast description and all supporting information requires a subscription, which BC Hydro has not purchased. BC Hydro did not consider or use this forecast in creating the price forecasts included in the QEM.

A schedule that sets out the GLJA forecast of annual gas prices at Huntingdon is provided in the response to question BCUC IR 1.26.9.

26.0 Reference: CFT Report, p. 12

1.26.6 Please provide a schedule showing current forward NYMEX gas prices at Henry Hub for as far into the future as information is available, and the corresponding gas prices at Huntingdon in then-current and real Canadian dollars per gigajoule. Please identify the date of the forward price strip that was used, and identify all assumptions and factors that were used to generate the schedule.

RESPONSE:

NYMEX is relatively illiquid outside the near term. The NYMEX strip generated on 7 December 2004 shows 10 of the 12 months that traded for calendar year 2007. On this day, 39,556 contracts were settled in near month for January 2005 and 20,740 contracts settled for February 2005. However, only 782 contracts were settled for all of the months in 2007, of which 77% were concentrated in one month – May 2007. This is not unusual, in that over the last 3 months, NYMEX near-month traded an average of 52,213 gas futures contracts per day. Over that same period, daily trading for each month in 2007 averaged only 68 contracts.

Figure IR 1.26.6 below shows the relative liquidity of the NYMEX futures contract.

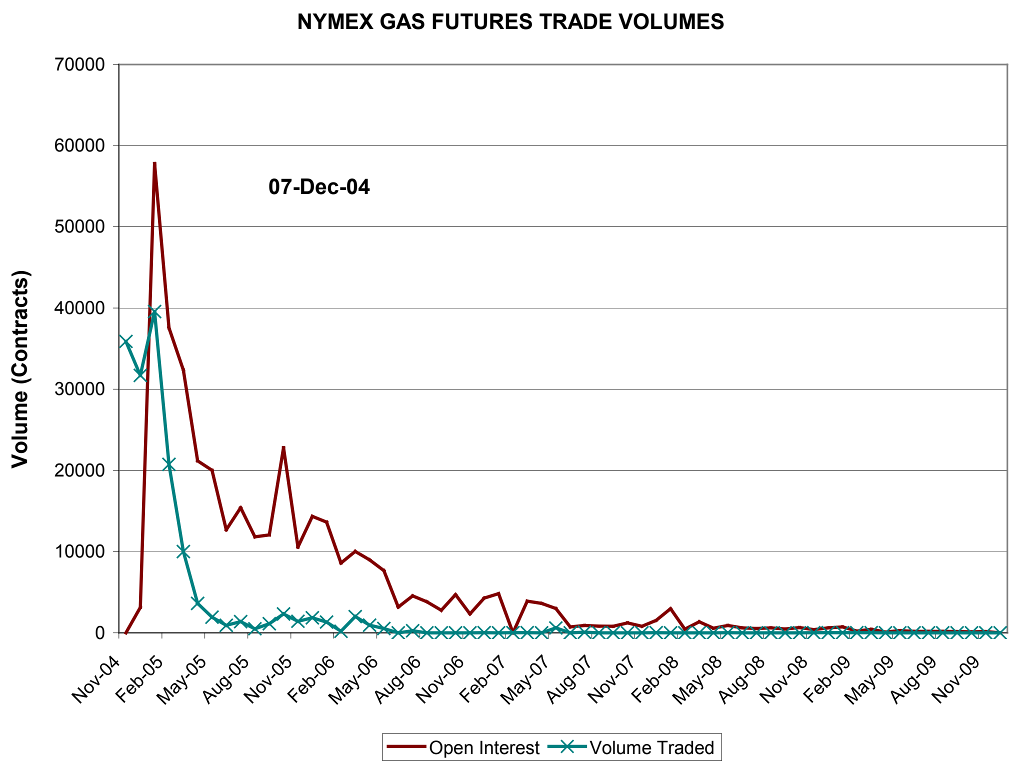

Table IR 1.26.6 shows futures prices for 07 December 2004. Where no trades occurred, no value is provided.

Table IR 1.26.6 Futures Gas Prices for NYMEX Trades

	LAST PRICE	Contracts Traded
Jan-05	6.62	39556
Feb-05	6.76	20740
Mar-05	6.69	10007
Apr-05	6.28	3623
May-05	6.20	1919
Jun-05	6.24	928
Jul-05	6.28	1376
Aug-05	6.30	512
Sep-05	6.28	1115
Oct-05	6.31	2319
Nov-05	6.60	1439
Dec-05	6.89	1840
Jan-06	7.10	1328
Feb-06	7.10	198
Mar-06	6.89	1997
Apr-06	6.08	952
May-06	5.96	537
Jun-06	5.97	2
Jul-06	6.01	250
Aug-06	-	No Trades
Sep-06	6.00	7
Oct-06	6.02	11
Nov-06	6.29	4
Dec-06	6.56	20
Jan-07	-	No Trades
Feb-07	6.76	30
Mar-07	6.56	30
Apr-07	5.74	1
May-07	5.60	604
Jun-07	5.62	6
Jul-07	5.65	75
Aug-07	5.67	1
Sep-07	5.64	4
Oct-07	5.68	2
Nov-07	-	No Trades
Dec-07	6.22	29
Jan-08	-	No Trades
Feb-08	-	No Trades
Mar-08	-	No Trades
Apr-08	5.41	10

	LAST PRICE	Contracts Traded
May-08	5.29	13
Jun-08	5.31	10
Jul-08	5.32	10
Aug-08	5.33	10
Sep-08	5.32	10
Oct-08	5.34	10
Nov-08	5.61	14
Dec-08	5.89	14
Jan-09	6.10	14
Feb-09	6.08	14
Mar-09	5.91	14
Apr-09	-	No Trades
May-09	-	No Trades
Jun-09	-	No Trades
Jul-09	-	No Trades
Aug-09	-	No Trades
Sep-09	-	No Trades
Oct-09	-	No Trades
Nov-09	-	No Trades
Dec-09	-	No Trades

26.0 Reference: CFT Report, p. 12

1.26.7 Please use the Huntingdon prices for 2007 from the preceding response that is based on NYMEX forward prices, to generate a schedule of projected Huntingdon prices in then-current and real Canadian dollars per gigajoule, assuming that Huntingdon prices maintain their value in real terms after 2007.

RESPONSE:

Please see Table IR 1.26.7 (expressed in current dollars) which was created using the average yearly NYMEX forward prices for 2007. This yearly value was shaped into a monthly resolution using the same seasonal pattern in BC Hydro's QEM EIA-based forecast, and then escalated at inflation. This table expressed in real (2007) dollars would then be a repetition of the 2007 prices. For these values expressed as real (2003) dollars, see the response to BCUC IR 1.26.9.

Table IR 1.26.7 – Schedule of Projected Huntingdon Prices Based on NYMEX Forward Prices

Huntingdon /Sumas $C/GJ nominal (current)	Year																									
Month	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	8.34	8.49	8.64	8.80	8.96	9.13	9.29	9.46	9.64	9.82	10.00	10.19	10.38	10.58	10.78	10.98	11.19	11.40	11.62	11.83	12.04	12.25	12.46	12.67	12.89	13.10
2	8.17	8.32	8.48	8.63	8.79	8.96	9.13	9.30	9.47	9.65	9.84	10.03	10.22	10.41	10.61	10.82	11.02	11.24	11.45	11.66	11.87	12.09	12.30	12.51	12.72	12.93
3	7.81	7.96	8.11	8.27	8.43	8.60	8.76	8.94	9.11	9.29	9.48	9.66	9.85	10.05	10.25	10.45	10.66	10.87	11.09	11.30	11.51	11.72	11.93	12.14	12.36	12.57
4	6.90	7.05	7.21	7.37	7.53	7.69	7.86	8.03	8.21	8.39	8.57	8.76	8.95	9.14	9.34	9.55	9.76	9.97	10.18	10.39	10.60	10.82	11.03	11.24	11.45	11.66
5	6.78	6.93	7.08	7.24	7.40	7.57	7.74	7.91	8.08	8.26	8.45	8.63	8.83	9.02	9.22	9.42	9.63	9.85	10.06	10.27	10.48	10.69	10.91	11.12	11.33	11.54
6	6.77	6.92	7.08	7.24	7.40	7.56	7.73	7.90	8.08	8.26	8.44	8.63	8.82	9.01	9.21	9.42	9.63	9.84	10.06	10.26	10.48	10.69	10.90	11.11	11.32	11.53
7	6.77	6.92	7.08	7.24	7.40	7.56	7.73	7.90	8.08	8.26	8.44	8.63	8.82	9.01	9.21	9.42	9.63	9.84	10.06	10.26	10.48	10.69	10.90	11.11	11.32	11.53
8	6.78	6.93	7.08	7.24	7.40	7.57	7.73	7.91	8.08	8.26	8.44	8.63	8.82	9.02	9.22	9.42	9.63	9.84	10.06	10.27	10.48	10.69	10.90	11.11	11.33	11.54
9	6.78	6.93	7.08	7.24	7.40	7.57	7.73	7.91	8.08	8.26	8.44	8.63	8.82	9.02	9.22	9.42	9.63	9.84	10.06	10.27	10.48	10.69	10.90	11.11	11.33	11.54
10	6.81	6.96	7.11	7.27	7.43	7.60	7.77	7.94	8.11	8.29	8.48	8.66	8.86	9.05	9.25	9.46	9.66	9.88	10.09	10.30	10.51	10.72	10.94	11.15	11.36	11.57
11	7.43	7.58	7.73	7.89	8.05	8.22	8.38	8.56	8.73	8.91	9.09	9.28	9.47	9.67	9.87	10.07	10.28	10.49	10.71	10.92	11.13	11.34	11.55	11.76	11.98	12.19
12	7.84	7.99	8.14	8.30	8.46	8.63	8.80	8.97	9.14	9.32	9.51	9.69	9.89	10.08	10.28	10.48	10.69	10.90	11.12	11.33	11.54	11.75	11.96	12.18	12.39	12.60
Average	7.26	7.41	7.57	7.73	7.89	8.05	8.22	8.39	8.57	8.75	8.93	9.12	9.31	9.51	9.71	9.91	10.12	10.33	10.55	10.75	10.97	11.18	11.39	11.60	11.81	12.02

26.0 Reference: CFT Report, p. 12

1.26.8 Further to the reference to a high gas price scenario on page 2 of Appendix J, please describe the basis and source for the forecast, and provide a schedule of these prices at Huntingdon in then-current and real Canadian dollars per gigajoule.

RESPONSE:

Please see the response to BCUC IR 1.14.6 for the requested description and source. The requested schedules are attached as Table IR 1.26.8(a) (current prices) and Table IR 1.26.8(b) (real prices).

Table IR 1.26.8(a) Huntingdon Prices for High Gas Price Scenario (Current $C/GJ)

Month	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	7.85	8.10	7.95	7.95	8.28	8.66	9.04	9.28	9.68	9.87	10.02	10.06	10.12	10.53	10.98	11.09	11.25	11.41	11.55	11.69	11.84	11.98	12.13	12.28	12.42	12.57
2	7.69	7.93	7.79	7.79	8.12	8.49	8.87	9.12	9.52	9.70	9.85	9.89	9.96	10.36	10.82	10.92	11.09	11.24	11.38	11.53	11.67	11.82	11.96	12.11	12.25	12.40
3	7.32	7.57	7.42	7.42	7.75	8.13	8.51	8.75	9.15	9.34	9.49	9.53	9.59	10.00	10.45	10.56	10.73	10.88	11.02	11.16	11.31	11.46	11.60	11.75	11.89	12.04
4	6.42	6.66	6.52	6.52	6.85	7.23	7.60	7.85	8.25	8.43	8.58	8.62	8.69	9.10	9.55	9.65	9.82	9.97	10.12	10.26	10.40	10.55	10.70	10.84	10.99	11.13
5	6.29	6.54	6.39	6.40	6.72	7.10	7.48	7.72	8.13	8.31	8.46	8.50	8.57	8.97	9.43	9.53	9.70	9.85	9.99	10.14	10.28	10.43	10.57	10.72	10.86	11.01
6	6.29	6.53	6.39	6.39	6.72	7.10	7.47	7.72	8.12	8.30	8.46	8.49	8.56	8.97	9.42	9.52	9.69	9.84	9.99	10.13	10.27	10.42	10.57	10.71	10.86	11.00
7	6.29	6.53	6.39	6.39	6.72	7.10	7.47	7.72	8.12	8.30	8.46	8.49	8.56	8.97	9.42	9.52	9.69	9.84	9.99	10.13	10.27	10.42	10.57	10.71	10.86	11.00
8	6.29	6.54	6.39	6.39	6.72	7.10	7.48	7.72	8.12	8.31	8.46	8.50	8.56	8.97	9.42	9.53	9.69	9.85	9.99	10.13	10.28	10.42	10.57	10.72	10.86	11.01
9	6.29	6.54	6.39	6.39	6.72	7.10	7.48	7.72	8.12	8.31	8.46	8.50	8.56	8.97	9.42	9.53	9.69	9.85	9.99	10.13	10.28	10.42	10.57	10.72	10.86	11.01
10	6.32	6.57	6.43	6.43	6.76	7.13	7.51	7.76	8.16	8.34	8.49	8.53	8.60	9.00	9.46	9.56	9.73	9.88	10.02	10.17	10.31	10.46	10.60	10.75	10.89	11.04
11	6.94	7.19	7.04	7.04	7.37	7.75	8.13	8.37	8.77	8.96	9.11	9.15	9.21	9.62	10.07	10.18	10.34	10.50	10.64	10.78	10.93	11.07	11.22	11.37	11.51	11.66
12	7.35	7.60	7.45	7.46	7.78	8.16	8.54	8.78	9.19	9.37	9.52	9.56	9.62	10.03	10.49	10.59	10.76	10.91	11.05	11.20	11.34	11.49	11.63	11.78	11.92	12.07
Average	6.78	7.02	6.88	6.88	7.21	7.59	7.96	8.21	8.61	8.79	8.95	8.99	9.05	9.46	9.91	10.01	10.18	10.33	10.48	10.62	10.77	10.91	11.06	11.20	11.35	11.49

Table IR 1.26.8(b) Huntingdon Prices for High Gas Price Scenario (Real 2003 $C/GJ)

Month	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	7.23	7.30	7.02	6.88	7.02	7.19	7.35	7.39	7.55	7.54	7.49	7.37	7.26	7.40	7.56	7.48	7.43	7.38	7.32	7.25	7.19	7.13	7.07	7.01	6.94	6.88
2	7.08	7.15	6.88	6.74	6.88	7.05	7.21	7.26	7.42	7.41	7.37	7.24	7.15	7.28	7.45	7.36	7.32	7.27	7.21	7.15	7.09	7.03	6.97	6.91	6.85	6.79
3	6.74	6.83	6.55	6.42	6.57	6.75	6.92	6.97	7.13	7.13	7.10	6.98	6.88	7.03	7.19	7.12	7.08	7.04	6.98	6.92	6.87	6.82	6.76	6.71	6.65	6.59
4	5.91	6.01	5.76	5.64	5.80	6.00	6.18	6.25	6.43	6.44	6.42	6.31	6.23	6.39	6.57	6.51	6.48	6.45	6.41	6.36	6.32	6.28	6.24	6.19	6.14	6.09
5	5.79	5.90	5.64	5.54	5.69	5.89	6.08	6.15	6.34	6.35	6.33	6.23	6.15	6.30	6.49	6.42	6.40	6.37	6.33	6.29	6.25	6.21	6.16	6.12	6.07	6.03
6	5.79	5.89	5.64	5.53	5.69	5.89	6.07	6.15	6.33	6.34	6.33	6.22	6.14	6.30	6.48	6.42	6.40	6.36	6.33	6.28	6.24	6.20	6.16	6.11	6.07	6.02
7	5.79	5.89	5.64	5.53	5.69	5.89	6.07	6.15	6.33	6.34	6.33	6.22	6.14	6.30	6.48	6.42	6.40	6.36	6.33	6.28	6.24	6.20	6.16	6.11	6.07	6.02
8	5.79	5.90	5.64	5.53	5.69	5.89	6.08	6.15	6.33	6.35	6.33	6.23	6.14	6.30	6.48	6.42	6.40	6.37	6.33	6.28	6.25	6.20	6.16	6.12	6.07	6.03
9	5.79	5.90	5.64	5.53	5.69	5.89	6.08	6.15	6.33	6.35	6.33	6.23	6.14	6.30	6.48	6.42	6.40	6.37	6.33	6.28	6.25	6.20	6.16	6.12	6.07	6.03
10	5.82	5.92	5.68	5.56	5.73	5.92	6.10	6.18	6.36	6.37	6.35	6.25	6.17	6.32	6.51	6.44	6.42	6.39	6.35	6.31	6.26	6.22	6.18	6.14	6.09	6.05
11	6.39	6.48	6.22	6.09	6.24	6.43	6.61	6.66	6.84	6.84	6.81	6.70	6.61	6.76	6.93	6.86	6.83	6.79	6.74	6.69	6.64	6.59	6.54	6.49	6.44	6.39
12	6.77	6.85	6.58	6.45	6.59	6.77	6.94	6.99	7.17	7.16	7.12	7.00	6.90	7.05	7.22	7.14	7.10	7.06	7.00	6.95	6.89	6.84	6.78	6.72	6.66	6.61
Average	6.24	6.33	6.08	5.95	6.11	6.30	6.47	6.54	6.71	6.71	6.69	6.59	6.49	6.65	6.82	6.75	6.72	6.68	6.64	6.59	6.54	6.49	6.45	6.39	6.35	6.29

26.0 Reference: CFT Report, p. 12

1.26.9 Further to the preceding responses, please provide a schedule and figure that sets out for ready comparison the following projections of annual gas prices at Huntingdon in real Canadian dollars per gigajoule:

- BC Hydro updated reference price forecast from VIGP proceeding,
- BC Hydro high gas price forecast from VIGP proceeding,
- EIA Reference Case forecast issued in January 2004,
- EIA High Case forecast issued in January 2004,
- GLJA most current forecast,
- Current NYMEX forward prices,
- Projection based on current 2007 NYMEX forward prices and zero real increases, and
- High gas price forecast referenced in Appendix J.

RESPONSE:

Please see Table IR 1.26.9. Please see response to BCUC IR 1.13.1 and 1.26.3 for an explanation of the "EIA High Case forecast issued in January 2004". As explained in the response to IR 1.26.3, the January 2004 "High Case" was not associated with EIA data. This should be properly referenced as the BC Hydro "High Gas Case". The current NYMEX forward prices are not shown in this table. Please see response to BCUC IR 1.26.6. Please also note that the Canadian prices were calculated using different exchange rates in effect when the forecast was made. Thus, the prices in each forecast are not comparable to each other.

Table IR 1.26.9 Miscellaneous Gas Price Forecasts and Projections

Year	VIGP Updated Reference (Real 2002 CAD/GJ)(1)	VIGP High Gas (Real 2002 CAD/GJ)(2)	EIA Reference from QEM (Real 2003 CAD/GJ)(3)	GJLA October 2004 (Real 2004 CAD/GJ)(4)	Current NYMEX 2007 - Zero Growth (Real 2003 CAD/GJ)(5)	High Gas from App J (Real 2003 CAD/GJ)(6)
2007	5.57	5.71	4.07	5.93	6.68	6.24
2008	5.47	5.56	4.15	5.62	6.68	6.33
2009	4.91	5.68	4.20	5.39	6.68	6.08
2010	4.41	5.87	4.02	5.09	6.68	5.95
2011	3.92	6.03	4.01	5.03	6.68	6.11
2012	3.93	6.12	4.21	4.98	6.68	6.30
2013	3.94	6.11	4.44	4.99	6.68	6.47
2014	3.94	6.25	4.63	4.99	6.68	6.54
2015	3.95	6.52	4.75	-	6.68	6.71
2016	3.96	6.75	4.93	-	6.68	6.71
2017	3.97	6.99	4.96	-	6.68	6.69
2018	3.98	7.29	4.95	-	6.68	6.58
2019	3.99	7.55	4.88	-	6.68	6.49
2020	4.00	8.08	4.89	-	6.68	6.65
2021	4.00	8.25	5.08	-	6.68	6.82
2022	4.01	8.27	5.23	-	6.68	6.75
2023	-	-	5.20	-	6.68	6.72
2024	-	-	5.20	-	6.68	6.68
2025	-	-	5.19	-	6.68	6.64

Notes:

1. **Prices obtained from June 2003 BC Hydro Price Forecast. This forecast was submitted during the VIGP hearing and updated the November 2002 forecast used in the original filing.**
2. **High Gas case from VIGP Hearing. Price increase in real terms is due, in part, to the decline in the exchange rate forecast from 0.62 to 0.57 over 2007-2025.**
3. **EIA Reference scenario from June 2004 BCH Price Forecast. This was the forecast used in the Quantitative Evaluation Methodology.**
4. **Price summary (annual) was obtained from the GJLA website. Description of forecast and assumptions requires a subscription. Prices converted to Real dollars with inflation factors consistent with the Call for Tenders evaluation methodology.**
5. **NYMEX futures for 2007 from December 7, 2004. These values extended with no real escalation for the remainder of the forecast horizon.**
6. **Converted to Real dollars with inflation factors consistent with the Call for Tenders evaluation methodology.**

27.0 Reference: CFT Report, p. 15, Appendix J
VIGP Decision, p. 57

1.27.1 Further to Table 5 on page 15 of the CFT Report, please confirm that the primary cause of the step change in F2008 in the capacity deficit for Vancouver Island is the zero rating for planning purposes of the high voltage direct current ("HVDC") systems to the Island. If this is not the case, please explain the primary reasons for the step change.

RESPONSE:

Confirmed.

27.0 Reference: CFT Report, p. 15, Appendix J
VIGP Decision, p. 57

1.27.2 Please confirm that the HVDC systems are assumed to be zero rated as of the end of December 2007, or provide the correct date.

RESPONSE:

BCTC has advised BC Hydro that the HVDC system is considered to be reliable from a system planning and reliability standpoint until the end of December 2007. After that point, the HVDC will be rated at 0 MW firm capacity.

The exact timing of the retirement of the HVDC system is impossible to predict with certainty, although the system's eventual failure is likely to be sudden. The winter peak can occur any time from the beginning of November to the end of February, with the greatest likelihood that it will occur in December or January.

The load forecasting convention is to publish the annual peak forecast for the entire fiscal year. In producing a monthly peak forecast for internal planning purposes, the annual peak forecast is allocated into 12 months. Since a monthly peak forecasting model is not formally used to develop a peak forecast for each month based on monthly drivers, the annual peak forecast for entire fiscal year is allocated 100% into December as a convention to produce a monthly peak forecast. This is done despite the fact that historical percentages show that it is almost equally likely for the peak to occur in December or January.

Over the past 30 years, the percentage of actual peaks on Vancouver Island that occurred over the months of October to March is shown in Table IR 1.27.2.

Table IR 1.27.2 Percentage of Annual Vancouver Island Peak Days – October to March

Month	Occurrence	% of Occurrence
October	0	0%
November	4	13%
December	12	40%
January	10	34%
February	4	13%
March	0	0%

27.0 Reference: CFT Report, p. 15, Appendix J
VIGP Decision, p. 57

1.27.3 Further to the Expected Energy Not Served ("EENS") diagram on page 57 of the VIGP Decision and Appendix J of the CFT Report, please provide an EENS diagram that shows the situation under the preferred Tier 1, Tier 2 and No Award scenarios. For each of the Tier 2 and No Award situations, please include a case that includes capacity provided by Demand Management and temporary generators as discussed on page 2 of Appendix J, and a case that does not include these additional resources.

RESPONSE:

This Information Request is out of scope.

28.0 Reference: CFT Report, p. 15

1.28.1 In Table 5 on page 15 of the CFT, how much capacity is assumed to be available from the Island Cogeneration Plant ("ICP")? Please explain the basis for the forecast.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

28.0 Reference: CFT Report, p. 15

1.28.2 What supply availability or reliability factor does BC Hydro assume for ICP? What has been the historical performance of the ICP in terms of scheduled and unscheduled outages? If the ICP availability has not been at least 97 percent, please explain in the context of the mandatory criteria for the CFT.

RESPONSE:

This Information Request is out of scope.

28.0 Reference: CFT Report, p. 15

1.28.3 Since the Commercial Operation Date of the ICP, please provide a listing of all outages or other periods when the facility was not available. For each, please identify whether it was a scheduled outage, the cause and the duration. Were any of the outages caused by lack of fuel supply?

RESPONSE:

This Information Request is out of scope.

28.0 Reference: CFT Report, p. 15

1.28.4 Please provide a concise description of each major outage, including all instances when service to customers on Vancouver Island was affected as a result. Please include the incident in mid to late October 2004. If ICP was out of service during the cold weather period in early January 2004, please include that period as well. For each outage, please outline the situation with regard to the rest of the electrical system, the cause of the ICP outage in technical terms, any changes that have been made to reduce the occurrence of such outages in the future and why BC Hydro expects Duke Point will be more or less susceptible than ICP to such outages. (For example, if ICP tripped off due to over-frequency, what was the over-frequency trip set at, what is it currently set at for ICP and what will be the setting for Duke Point?)

RESPONSE:

This Information Request is out of scope.

29.0 Reference: BCTC Capital Plan dated May 31, 2004, p. 105
CFT Report, pp. 14, 16, 17

BCTC stated at page 105 of the Capital Plan that the planned in-service date for the 230 kV AC line to Vancouver Island is October, 2008.

BC Hydro's response to the Commission's Information Request 1.5.2 in the Commission hearing into the TGVI 2004 Resource Plan and Liquefied Natural Gas ("LNG") Storage Project Application is found in Exhibit No. C7-4 for that proceeding. The response states; "…it is likely that BC Hydro will confirm the earliest in-service date for transmission reinforcement to Vancouver Island."

BC Hydro states at page 16 of the CFT Report; "Even with this acquisition, the preferred timing of new 230 kV AC cable circuit to Vancouver Island remains at that project's earliest in-service date of F2009."

BC Hydro states at page 17 of the CFT Report; "The common assumptions used for the analysis of CFT cost effectiveness are as follows: ... 230 kV transmission cable – in service after March 2009."

1.29.1 Further to BC Hydro's responses to BCUC IRs 1.5.1 and 1.5.2 in Exhibit C7-4 of the TGVI proceeding, please clarify whether the "2009 Cable In-Service" cases in Attachment A of Appendix J assume the 230 kV AC connection to Vancouver Island will be in service by October 2008. If not, please explain what these cases assume.

RESPONSE:

In Attachment A of Appendix J, the "2009 Cable In-Service" cases assume that the 230 kV transmission circuit is in-service by October 2008 (i.e. within the fiscal year ending 31 March 2009).

29.0 Reference: BCTC Capital Plan dated May 31, 2004, p. 105
CFT Report, pp. 14, 16, 17

BCTC stated at page 105 of the Capital Plan that the planned in-service date for the 230 kV AC line to Vancouver Island is October, 2008.

BC Hydro's response to the Commission's Information Request 1.5.2 in the Commission hearing into the TGVI 2004 Resource Plan and Liquefied Natural Gas ("LNG") Storage Project Application is found in Exhibit No. C7-4 for that proceeding. The response states; "…it is likely that BC Hydro will confirm the earliest in-service date for transmission reinforcement to Vancouver Island."

BC Hydro states at page 16 of the CFT Report; "Even with this acquisition, the preferred timing of new 230 kV AC cable circuit to Vancouver Island remains at that project's earliest in-service date of F2009."

BC Hydro states at page 17 of the CFT Report; "The common assumptions used for the analysis of CFT cost effectiveness are as follows: … 230 kV transmission cable – in service after March 2009."

1.29.2 If Attachment A of Appendix J does not assume the 230 kV AC cable will be in service by October 2008, please provide a form of Attachment A that has been expanded to show (for each scenario) the situation where the 230 kV AC cables are assumed to be in service for October 2008.

RESPONSE:

Please see the response to BCUC IR 1.29.1.

29.0 Reference: BCTC Capital Plan dated May 31, 2004, p. 105
CFT Report, pp. 14, 16, 17

BCTC stated at page 105 of the Capital Plan that the planned in-service date for the 230 kV AC line to Vancouver Island is October, 2008.

BC Hydro's response to the Commission's Information Request 1.5.2 in the Commission hearing into the TGVI 2004 Resource Plan and Liquefied Natural Gas ("LNG") Storage Project Application is found in Exhibit No. C7-4 for that proceeding. The response states; "…it is likely that BC Hydro will confirm the earliest in-service date for transmission reinforcement to Vancouver Island."

BC Hydro states at page 16 of the CFT Report; "Even with this acquisition, the preferred timing of new 230 kV AC cable circuit to Vancouver Island remains at that project's earliest in-service date of F2009."

BC Hydro states at page 17 of the CFT Report; "The common assumptions used for the analysis of CFT cost effectiveness are as follows: … 230 kV transmission cable – in service after March 2009."

1.29.3 Please explain the rationale for using an F2010 in-service date as the common assumption for comparison in the Appendix J "CFT Cost Effectiveness Analysis."

RESPONSE:

As explained in the response to BCUC IR 1.29.1, the "2009 Cable In-Service" refers to an in-service date of October 2008. In the CFT, BC Hydro defined dependable capacity on the basis of availability over October to March inclusive. To be consistent with the CFT criteria, any delay in the expected October 2008 in-service would mean that BC Hydro could not rely on the 230 kV transmission circuit as a firm capacity resource to serve the winter 2008/09 peak season, for planning purposes. Any circumstance that causes even a small delay in the October 2008 in-service date would require BC Hydro to implement contingency measures to ensure Vancouver Island's 2007/08 winter peak requirements are met. There are a number of unknown variables affecting the in-service date of the proposed 230 kV circuit, such as the extent, duration and scope of First Nations and public consultation processes, and Canadian and US permit application approval processes. With these considerations, BC Hydro believes it is prudent planning to assume a one year delay in the cable availability (i.e. to October 2009) as the base case scenario in the Cost Effectiveness Analysis.

30.0 Reference: CFT Report, p. 14

BC Hydro states; "Senior management also requested additional analysis in order to fully assess whether the selected CFT portfolio provided the most cost effective supply solution for BC Hydro's ratepayers compared to its contingency plan options and taking into account the Commission's criteria for establishing cost-effectiveness, including cost, reliability, dispatchability, timing and location."

1.30.1 Please provide the detailed results of the supplementary analysis with respect to the quantification of reliability, dispatchability and timing characteristics of the Tier 1 and Tier 2 solutions analyzed.

RESPONSE:

The Cost Effectiveness Analysis in Appendix J is the supplementary analysis.

31.0 Reference: CFT Report, p. 2

BC Hydro states; "The plant was thus expected to generate 265 MW of dependable capacity and to dispatch up to 2,100 GWh of energy per year." Duke Point plant rating vs. VIGP (252 MW vs. 265 MW)

1.31.1 Are the gas turbine, heat recovery steam generator and steam turbine in the Tier 1 Project substantially the same as proposed for the VIGP? Please outline any material differences. In particular, what model of gas turbine is proposed for the Duke Point plant, and how does its efficiency and reliability compare to that proposed for VIGP?

RESPONSE:

The standards that a CFT bidder was required to meet were equivalent to the performance that was anticipated from the VIGP facilities. However, the risk of assuring that performance passes from BC Hydro to Duke Point Power LLP under the EPA structure.

According to the information provided by Duke Point Power LLP, the gas turbine, heat recovery steam generator and steam turbine generator in the Duke Point project are the same design as had been proposed for the VIGP. The Duke Point project will employ an "F" class gas turbine along with the existing Fuji Electric steam turbine generator owned by BC Hydro.

31.0 Reference: CFT Report, p. 2

BC Hydro states; "The plant was thus expected to generate 265 MW of dependable capacity and to dispatch up to 2,100 GWh of energy per year." Duke Point plant rating vs. VIGP (252 MW vs. 265 MW)

1.31.2 Please provide an explanation for the difference in nominal capacities between the Tier 1 Project (252 MW) and the VIGP (265 MW).

RESPONSE:

According to information provided by Duke Point Power LLP, the Duke Point Power Project's Bid Capacity of 252 megawatts represents the nominal degraded 25 year flat capacity, as per the requirements of the CFT. The project's nominal new and clean capacity is 265 megawatts.

32.0 Reference: CFT Report, p.23, Section 7, VIGP Benchmark;
Appendix L – VIGP Benchmark Analysis
Commission VIGP Decision and Order No. G-55-03

1.32.1 Please provide tables similar to Table 8 (page 23) and Appendix L for each of the projects in Tenders A through F as identified on page 13 of Appendix K, Tab 4.

RESPONSE:

<u>THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.</u>

32.0 Reference: CFT Report, p.23, Section 7, VIGP Benchmark;
Appendix L – VIGP Benchmark Analysis
Commission VIGP Decision and Order No. G-55-03

1.32.2 Please provide Cost of Service Schedules similar to Appendix A of the Commission's VIGP Decision for both the preferred Tier 1 (Duke Point) and Tier 2 resource additions, and for the VIGP Benchmark Analysis assumptions set out in Appendix L.

RESPONSE:

This Information Request is out of scope.

33.0 Reference: CFT Report, p. 19

BC Hydro states; "The conclusion of the cost-effectiveness analysis was that the Tier 1 result (awarding an EPA to the Duke Point Power Project) is the most cost-effective outcome for ratepayers on both a quantitative and risk-adjusted basis. As stated in the VIGP Decision, cost effective includes considerations such as reliability, dispatchability, timing, location, safety and cost to ratepayers and the financial capability of the utility."

1.33.1 Please provide the technical specifications for the Tier 1 Project.

RESPONSE:

All information on technical specifications provided by Duke Point Power LLP is contained in Appendix 5 of the executed EPA, which has been provided to the Commission in confidence on 19 November 2004.

33.0 Reference: CFT Report, p. 19

BC Hydro states; "The conclusion of the cost-effectiveness analysis was that the Tier 1 result (awarding an EPA to the Duke Point Power Project) is the most cost-effective outcome for ratepayers on both a quantitative and risk-adjusted basis. As stated in the VIGP Decision, cost effective includes considerations such as reliability, dispatchability, timing, location, safety and cost to ratepayers and the financial capability of the utility."

1.33.2 Please provide the first four years of expected dispatch and maintenance schedules for the Tier 1 Project.

RESPONSE:

The first four years of expected dispatch (net of maintenance) for the Tier 1 project as determined by the QEM are 518 GWh (2007), 1260 GWh (2008), 1468 GWh (2009), and 1567 GWh (2010).

Table IR 1.33.2 represents the expected dispatch (net of maintenance) of the Tier 1 project as determined by the QEM, for the full 25 year term, for both the partial recovery and full recovery electricity price forecast scenarios.

Table IR 1.33.2 Expected Dispatch of DPP

Calendar Year	Expected GWh Dispatch (Partial Recovery)	Expected GWh Dispatch (Full recovery)
2007 (8 months)	518	518
2008	1260	1260
2009	1468	1468
2010	1567	1567
2011	1679	2022
2012	1679	2022
2013	1567	1983
2014	1679	2109
2015	1679	2082
2016	1567	1963
2017	1679	2082
2018	1679	2082
2019	1567	1963
2020	1679	2053
2021	1679	2053
2022	1701	1941
2023	1813	2053
2024	1841	2053
2025	1878	1941
2026	1960	2053
2027	1960	2053
2028	1856	1941
2029	1960	2053
2030	1960	2053
2031	1856	1941
2032 (4 months)	642	703

33.0 Reference: CFT Report, p. 19

BC Hydro states; "The conclusion of the cost-effectiveness analysis was that the Tier 1 result (awarding an EPA to the Duke Point Power Project) is the most cost-effective outcome for ratepayers on both a quantitative and risk-adjusted basis. As stated in the VIGP Decision, cost effective includes considerations such as reliability, dispatchability, timing, location, safety and cost to ratepayers and the financial capability of the utility."

1.33.3 Please provide industry benchmarks and other reference data for the availability and reliability indices and maintenance requirements and shutdown periods for the critical equipment in the Tier 1 Project as a function of annual operating factor and annual stops/starts.

RESPONSE:

According to information provided by Duke Point Power LLP, the Duke Point Project will utilize an "F" class gas turbine using combined cycle design technology which has been proven by the installation and operation of hundreds of similar facilities throughout the world. The "F" class design is the most utilized gas turbine design ever, with the highest number of installed units in operation.

Availability for industry standard "F" class design plants ranges from 93% to 97% on an annual basis. For this purpose, availability is measured by factoring in all planned and unplanned outages during the course of a year.

Reliability for industry standard "F" class design plants averages 98% as a function of annual operating factor. Reliability is measured by factoring in all unplanned outages during the course of a year.

The industry standard capability for "F" class design plants is 200-400 starts per year.

34.0 Reference: CFT Report, Appendix H – Quantitative Evaluation Methodology, p. 4
CFT Report, Appendix K4 – Independent Reviewer Report No. 4, p. 13

1.34.1 Please provide the Data Sourced from the Tender as identified on pages 4, 5 and 6 of Appendix H, for each of the projects received as identified on page 7 of Appendix K4.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

34.0 Reference: CFT Report, Appendix H – Quantitative Evaluation Methodology, p. 4
CFT Report, Appendix K4 – Independent Reviewer Report No. 4, p. 13

1.34.2 Please provide the availability and reliability analysis associated with each project identified on page 7 of Appendix K4.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

35.0 Reference: CFT Report, Appendix G – Addendum 10 to the CFT, p. 1

1.35.1 Please provide the rationale for the change in the required EPA initial term from a minimum of 10 years to a minimum of 25 years.

RESPONSE:

Making this change was consistent with the Commission's urging that a simplified evaluation model be used in the CFT. It eliminated the complexity and potential unfairness associated with the evaluation with comparing tenders for contracts of varying terms. BC Hydro would have been required to make backfilling assumptions for energy and capacity requirements beyond the expiry date of the contract to a term equal to the term of the longest contract bid. In conjunction with the change to a fixed 25-year term, BC Hydro relaxed the mandatory requirements for long-term fuel supply in order to make it easier for non-gas projects to bid.

Moreover, BC Hydro wished to acquire a long-term power supply, thereby avoiding the need to engage in a further procurement process on expiry of a 10-year contract. BC Hydro considered 25 years to be an appropriate standard that would enable bidders, in the absence of a ready electricity market in British Columbia, to structure a financial model that would assure competitive pricing and the ability to secure required financing.

35.0 Reference: CFT Report, Appendix G – Addendum 10 to the CFT, p. 1

1.35.2 Please show the projected dispatch of the Tier 1 and Tier 2 solutions in years 5 through 25, considering the planned transmission-side supply projects to Vancouver Island, given Mainland energy costs of 5%, 10% and 15% lower than Tier 1 costs (with adjustments for losses and delivery charges).

RESPONSE:

The expected dispatch does not depend on the assumption made for Mainland energy costs, but on the spread between the gas and electricity price forecasts. Because the model is not driven by Mainland energy costs, the expected dispatch would be the same for all three scenarios.

36.0 Reference: CFT Report, pp. 7, 8, 9, 12, Table 2 and section 2.7

BC Hydro states that network upgrade costs were provided by BCTC, and that;

"During May 2004, the pre-qualified bidders filed applications for interconnection studies with British Columbia Transmission Corporation ("BCTC") and provided final comments to BC Hydro on the preliminary form agreements. Following a Tender workshop in early July, nine of the pre-qualified bidders submitted project-specific revisions to BC Hydro along with detailed descriptions of their proposed generation facilities."

1.36.2 For each of the projects identified in the previous question, please supply a summary of the scope and cost of the system requirements and reinforcements:

- to the bidders' account; and
- to BC Hydro's/BCTC's account (borne by the system),

and the rationale for scope and cost split for each of the projects.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

36.0 Reference: CFT Report, pp. 7, 8, 9, 12, Table 2 and section 2.7

BC Hydro states that network upgrade costs were provided by BCTC, and that;

"During May 2004, the pre-qualified bidders filed applications for interconnection studies with British Columbia Transmission Corporation ("BCTC") and provided final comments to BC Hydro on the preliminary form agreements. Following a Tender workshop in early July, nine of the pre-qualified bidders submitted project-specific revisions to BC Hydro along with detailed descriptions of their proposed generation facilities."

1.36.1 Please provide the BCTC interconnection studies for the nine pre-qualified bidders' projects.

RESPONSE:

<u>THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.</u>

36.0 Reference: CFT Report, pp. 7, 8, 9, 12, Table 2 and section 2.7

BC Hydro states that network upgrade costs were provided by BCTC, and that;

"During May 2004, the pre-qualified bidders filed applications for interconnection studies with British Columbia Transmission Corporation ("BCTC") and provided final comments to BC Hydro on the preliminary form agreements. Following a Tender workshop in early July, nine of the pre-qualified bidders submitted project-specific revisions to BC Hydro along with detailed descriptions of their proposed generation facilities."

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RESPONSE:

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1.36.2 For each of the projects identified in the previous question, please supply a summary of the scope and cost of the system requirements and reinforcements:

- to the bidders' account; and
- to BC Hydro's/BCTC's account (borne by the system),

and the rationale for scope and cost split for each of the projects.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

36.0 Reference: CFT Report, pp. 7, 8, 9, 12, Table 2 and section 2.7

BC Hydro states that network upgrade costs were provided by BCTC, and that;

"During May 2004, the pre-qualified bidders filed applications for interconnection studies with British Columbia Transmission Corporation ("BCTC") and provided final comments to BC Hydro on the preliminary form agreements. Following a Tender workshop in early July, nine of the pre-qualified bidders submitted project-specific revisions to BC Hydro along with detailed descriptions of their proposed generation facilities."

1.36.3 Please provide the detailed descriptions of the proposed generation facilities as described above, and identify those descriptions that eventually became the Tier 1 and Tier 2 projects.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

36.0 Reference: CFT Report, pp. 7, 8, 9, 12, Table 2 and section 2.7

BC Hydro states that network upgrade costs were provided by BCTC, and that;

"During May 2004, the pre-qualified bidders filed applications for interconnection studies with British Columbia Transmission Corporation ("BCTC") and provided final comments to BC Hydro on the preliminary form agreements. Following a Tender workshop in early July, nine of the pre-qualified bidders submitted project-specific revisions to BC Hydro along with detailed descriptions of their proposed generation facilities."

1.36.4 Please supply copies of the bidder registration forms (CFT Report, Appendix B: Call for Tenders, Appendix 3) that were submitted.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

37.0 Reference: CFT Report, Tab J, p. 1

BC Hydro states that the Tier 1 case will produce 1800 GWh of energy per year based on the QEM dispatch model. BC Hydro also states that there will be no energy shortfall until the year 2010.

1.37.1 Please provide a table showing the energy load/resource balances from 2010 to 2020. If the shortfall in 2010 is not 1800 GWh, why is 1800 GWh assumed to be the energy required from 2010 onward?

RESPONSE:

Table IR 1.37.1 provides the system energy balance based on the October 2004 load forecast that was used in the cost effectiveness analysis. This indicates a firm energy deficit as of F2010.

The Mainland resource addition in 2009 was assumed to have the same annual energy contribution as the Tier 1 in order to enable this simplified portfolio analysis. Nevertheless, an 1800 GWh addition in 2009 is not a proportionately large increment. It is not typically practicable to scale supply additions to exactly match annual load growth.

Table IR 1.37.1 System Firm Energy Demand / Supply Balance

System Energy Supply - Demand											
	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
October 2004 Forecast before Power Smart	60,434	61,160	62,165	63,225	64,263	65,465	66,449	67,524	68,619	69,717	70,871
October 2004 Forecast with Power Smart	57,790	58,355	59,184	60,139	61,162	62,375	63,408	64,525	65,638	66,749	67,948
Heritage Hydro	48,845	48,845	48,845	48,845	48,845	48,845	48,845	48,845	48,845	48,845	48,845
Planned Resource Smart	469	494	541	587	587	587	598	598	598	598	624
Existing Purchase Contracts	8,104	8,104	8,104	8,104	8,061	7,738	6,811	6,811	6,811	6,811	6,811
Total Supply	**57,383**	**57,418**	**57,443**	**57,490**	**57,493**	**57,170**	**56,243**	**56,254**	**56,254**	**56,254**	**56,254**
Supply Deficit based on Forecast with Power Smart	-407	-937	-1,741	-2,649	-3,669	-5,205	-7,165	-8,271	-9,384	-10,496	-11,695

38.0 Reference: CFT Report, Tab J, p. 1

BC Hydro states that in order to compare the three CFT outcomes it is necessary to equalize both energy and capacity added to the system under each scenario.

1.38.1 Does the Cost Effectiveness Analysis assign any costs to solutions with differing levels of reliability performance?

1.38.2 If so, please explain how these costs were derived and assigned?

1.38.3 If not, does BC Hydro believe all scenarios (Tiers) will be equivalent in terms of reliability?

1.38.4 If not, has BC Hydro explored ways to monetize different levels of reliability? Please explain.

RESPONSE:

1.38.1 No. The analytical methodology was intended to compare, at a high level, the expected costs of the three outcomes on a relatively comparable energy and capacity basis. The Tier 1 and Tier 2 projects met the Mandatory Reliability Criteria that were established as part of the CFT design. The contingency measures assumed for the Cost-Effectiveness Analysis were based on their relative reliability and cost certainty characteristics compared to other potential contingency supply options identified by BC Hydro (see response to BCUC IR 1.40.2).

As noted in response to BCUC IR 1.15.6, the Cost-Effectiveness Analysis also did not assign cost premiums to the contingency measures that reflected their higher risks with respect to date and cost certainty relative to the CFT results.

Reliability performance related to Mainland generation resources and the 230 kV AC transmission circuit is not a relevant issue in the Cost Effectiveness analysis since these resources are common to all three CFT scenarios. The main consideration with respect to the 230 kV AC transmission circuit assessed in the Cost-Effectiveness Analysis was date certainty.

1.38.2 Please see the response to BCUC IR 1.38.1.

1.38.3 No. For the contingency measures to be considered to provide the equivalent level reliability as the CFT results, CFT-equivalent reliability performance would need to be reflected in contractual agreements between BC Hydro and the suppliers. In contrast, the reliability performance requirements for the CFT Tier 1 award are contractually firm as per the terms of the EPA.

1.38.4 In its VIGP Decision, the Commission did not encourage BC Hydro to design a CFT process based on a reliability versus cost trade-off approach. Rather, it encouraged BC Hydro to develop a CFT process that would meet a specific minimum reliability requirement of 150 MW of dependable capacity with on-Island generation. The competitive and transparent nature of the CFT process would provide the basis for determining what resource or resources would provide that minimum level of reliability at the lowest cost. The Commission also encouraged BC Hydro to develop a simplified NPV cost model to determine the lowest cost resource(s).

39.0 Reference: CFT Report, Tab J, p. 2

BC Hydro has used a 4.8% energy loss factor for energy transferred from the mainland to VI.

1.39.1 Please explain how this factor was derived.

RESPONSE:

Loss factors are derived by a transmission system analysis which estimates the losses on the segments of the major transmission system such as Kelly Lake to Lower Mainland and Lower Mainland to Vancouver Island. The energy loss factor of 4.8% is the same loss factor used in the VIGP Application portfolio analysis. See VIGP Hearing transcript pages 1730-1731 and VIEC's response to Elk Valley Coal Corporation IR No. 1.3.1.

This energy loss factor of 4.8%is based on an assumption that Mainland resources would be located outside the Lower Mainland, e.g. in the Kelly Lake/Nicola Region. The average annual loss factor associated with transmitting energy from the Kelly Lake/Nicola Region to the Lower Mainland was estimated at 3.6%. The average annual loss factor associated with transmitting energy from the Lower Mainland to Vancouver Island was estimated at 1.2%. Therefore the difference in annual average losses between the assumed location of Mainland generation and Vancouver Island is the sum of these factors, or 4.8%.

40.0 Reference: CFT Report, p. 17 and Tab J, p. 2

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

1.40.1 Please explain the rationale for selecting temporary generation.

RESPONSE:

Please see BC Hydro's response to BCUC IR 1.40.2.

40.0 Reference: CFT Report, p. 17 and Tab J, p. 2

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

1.40.2 What other options were considered and why were they rejected?

RESPONSE:

BC Hydro considered a number of measures in addition to the NorskeCanada demand management proposal (NCDMP) and temporary generators, including:

- **issuing a small dependable capacity call;**
- **implementing residential load shifting programs;**
- **implementing residential time-of-use rates;**
- **eliminating the E-Pus program; and**
- **implementing several transmission capacity options**

These measures were originally identified as possible feasible contingency options if the CFT process did not meet Vancouver Island's full capacity and schedule requirements. BC Hydro does not consider these options to be alternatives to the CFT. Contingency measures were included in the cost-effectiveness analysis to allow a high level comparison of the Tier 1, Tier 2 and No Award scenarios on a similar energy and capacity basis.

Within the non-transmission contingency options, NCDMP and temporary generation were preferred because of their relative reliability compared to other contingency options.

NCDMP was considered to be lower cost relative to temporary generation and was therefore utilized first up to its maximum proposed contracted capacity of 140 MW. Any remaining capacity shortfall on Vancouver Island was assumed to be met using temporary generation. However, compared to the CFT Tier 1 result, both the NCDMP and temporary generation options were considered higher risk with respect to date and cost certainty. In addition, the reliability performance of the CFT Tier 1 award is contractually firm whereas there are no contractual agreements with NorskeCanada and temporary generation suppliers.

Consideration of the transmission options is addressed in response to BCUC IR 1.40.3.

40.0 Reference: CFT Report, p. 17 and Tab J, p. 2

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

1.40.3 What alternatives did BCTC offer for contingent capacity?

RESPONSE:

BCTC provided information on the following two transmission capacity options:

1. **Install new 230 kV submarine and overhead transmission circuits from the Lower Mainland to Vancouver Island. The target project earliest in-service date is October 2008.**
2. **Refurbish critical components of the existing HVDC transmission system to increase its operational reliability. BCTC's analysis indicated that the estimated reliability is not sufficient for the HVDC transmission system to be considered as firm capability beyond 2007.**

40.0 Reference: CFT Report, p. 17 and Tab J, p. 2

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

1.40.4 Does BC Hydro assume any energy backfill from the temporary generators?

RESPONSE:

No. The cost-effectiveness analysis was not intended to provide that level of precision.

40.0 Reference: CFT Report, p. 17 and Tab J, p. 2

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

1.40.5 Has BC Hydro modeled the temporary generators to determine if they would be economically dispatchable? If so, how much energy would be dispatched?

RESPONSE:

No. It was assumed that the temporary generators would receive environmental approvals on an emergency resource basis and the associated permits will only allow the generators to operate as needed. However, it is unlikely that temporary generators would be economically dispatchable based on distillate fuel costs and unit efficiency ratings.

40.0 Reference: CFT Report, p. 17 and Tab J, p. 2

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

1.40.6 Would temporary generators meet the required level of reliability? What is the assumed level of reliability?

RESPONSE:

Assuming temporary generators could be procured, sited, permitted and installed within the required in-service dates, BC Hydro believes these generators are technically capable of meeting the required level of reliability on an emergency resource basis. To be considered equivalent to CFT projects in terms of reliability performance, BC Hydro would also need to establish CFT-equivalent reliability performance requirements and timing as part of any contractual agreements with temporary generator suppliers.

There may be restrictions in the number of hours such generation could operate. Permits would likely restrict the number of allowed operating hours in a year, for example, and thus if there were a prolonged need a temporary generator might not be available due to permit restrictions.

The level of reliability performance for the CFT is provided in BC Hydro's response to BCUC IR 1.44.1.

40.0 Reference: CFT Report, p. 17 and Tab J, p. 2

BC Hydro assumes that temporary generation would be used to provide capacity backup in the Tier 2 scenario.

1.40.7 If the temporary generators are gas-fueled, what are BC Hydro's assumptions regarding gas supply for them?

RESPONSE:

The shortfall in the Tier 2 portfolio was filled by 140 MW from the NorskeCanada Demand Management proposal and does not require temporary generators when the 230 kV circuit is delayed.

41.0 Reference: CFT Report, p. 17

BC Hydro states that the assumption for electricity prices from the mainland generation is the same as for the Tier 1 CFT.

1.41.1 Please explain the rationale for this assumption.

RESPONSE:

THIS INFORMATION RESPONSE IS BEING FILED IN CONFIDENCE WITH THE BCUC.

41.0 Reference: CFT Report, p. 17

BC Hydro states that the assumption for electricity prices from the mainland generation is the same as for the Tier 1 CFT.

1.41.2 Why does BC Hydro assume a 250 MW CCGT equivalent for mainland generation? When would this be required?

RESPONSE:

Please see the response to BCUC IR 1.41.1.

42.0 Reference: CFT Report, p. 17

1.42.1 Please explain the assumptions used with regard to the Norske Demand Management proposal, including the minimum commitments required.

RESPONSE:

Assumptions used with regard to the NorskeCanada Demand Management proposal, including pricing and the minimum commitments required are based on NorskeCanada's Letter and Demand Management Proposal dated 02 September 2004, filed in response to BCTC's Capital Plan.

The assumptions used are contained in Section 3d (p. 13) of the proposal, assuming 10 days, 240 hours of continuous utilization. See also BC Hydro's response to BCUC IR 1.15.5.

43.0 Reference: CFT Report, Table 5, p. 15
BCUC VIGP Decision, Table 3.2, p. 25

1.43.1 Please provide a reconciliation table to correlate the values in Table 5 and Table 3.2 (from the references above), showing among other things, the specific effects of the E-Plus, Resource Smart and Green Energy capacity additions as directed by the VIGP Decision.

RESPONSE:

Table IR 1.43.1 reconciles the resources listed in table 5 of the CFT Report with Table 3.2 of the VIGP Decision in which the Commission summarized its conclusions regarding expected supply additions and load reductions.

TABLE 1.43.1		2003/04	2007/08	2011/12
Existing Hydro	Table 3.2	449	449	449
	Table 5 (note 1)		450	450
Existing Purchases	Table 3.2	2	2	2
	Table 5 (note 2)		n/a	n/a
Island Cogeneration	Table 3.2	240	240	240
	Table 5 (note 3)		235	235
Green Customer based Generation:				
	Table 3.2	0	30	40
	Table 5 (note 4)		31	31
500kV transmission and HVDC				
	Table 3.2	1540	1300	1300
	Table 5		1300	1300
Contracted Demand Reduction	Table 3.2 and Table 5	0	0	0
E-Plus	Table 3.2	15	15	15
	Table 5		0	0
Peak Shaving	Table 3.2 and Table 5	0	0	0
Resource Smart	Table 3.2	0	10	14
	Table 5		0	0

Note 1: With rounding, heritage hydro is 450 MW.

Note 2: Estimate of dependable capacity from IPPs that existed at time of VIGP Decision has been increased to 2.6 MW and is included in "Existing Purchase Contracts".

Note 3: In Table 5, ICP is included in "Existing Purchase Contracts" at 235 MW as of F2007, based on firm fuel supply. Since the VIGP Decision, dependable capacity with firm fuel supply was reduced from 240 MW to 235 MW due to a technical limitation that affected its maximum output. Since the CFT Report the maximum output of ICP has been increased back to 240 MW.

Note 4: In Table 5, 31 MW from existing green energy contracts are included with ICP in "Existing Purchase Contracts". No Customer-Based Generation contracts resulted from the Customer-Based Generation call. Table 5 does not include any assumption with respect to contracting additional Vancouver Island projects from future calls.

Please see BC Hydro's response to BCUC IR 1.43.2 for a discussion of Resource Smart.

43.0 Reference: CFT Report, Table 5, p. 15
BCUC VIGP Decision, Table 3.2, p. 25

1.43.2 Has there been any further development or exploration of dependable capacity additions through E-Plus, Peak-shaving, Resource Smart or Green Energy programs or initiatives since the VIGP application? If so, please provide details of these activities and identify the timing and amount of dependable capacity associated with each.

RESPONSE:

This discussion of E-Plus and Peak-shaving is out of scope.

Resource Smart:

During the VIGP deliberations, BC Hydro noted the potential for capacity increases at Ash River (6 MW) and John Hart (1 MW at each of 6 units). Since that time, Ash River upgrade was deferred in favour of other higher priority Resource Smart expenditures. As a result of recent revisions to the schedule of Resource Smart planned expenditures, John Hart upgrade is not included pending a decision on potential to redevelop the plant.

Green Energy:

BC Hydro has revised the dependable capacity from IPPs that were in-service at the time of the VIGP Application upward from 2 MW to 2.6 MW. Based on the results of Green Calls in 2001 and 2002 and the Customer Based Generation Call in 2001, BC Hydro currently estimates the contribution from existing and contracted IPPs (excluding ICP) at 31 MW as of F2007.

44.0 Reference: CFT Report, Appendix B – Call for Tenders issued October 31, 2003, Appendix 1

1.44.1 Please explain the rationale for assigning a guaranteed availability of 97% to Dependable Capacity during the period of October to March.

RESPONSE:

BC Hydro has consistently said that the 97% availability criterion is required because of the critical need for reliable new generation capacity on Vancouver Island to replace the dependable capacity from HVDC system by 2007. For the purpose of calculating a plant's monthly availability, properly scheduled maintenance is excluded. The 97% threshold is reasonable for all proven technologies and was developed based on BC Hydro's requirements rather than any particular generating technology.

The 97% availability threshold prescribed in the CFT equates to an annual availability factor of about 92%. During the VIGP hearing, BC Hydro indicated that it typically required an availability level of 92% from IPPs for dependable capacity purposes. The 92% factor is an annual average that assumes outage rates of 5% for planned maintenance and 3% for unplanned maintenance. The 97% availability factor used for CFT excludes planned maintenance and provides for a maximum forced outage rate of 3%.

The EPA contains a number of ways for a Seller to mitigate the impacts of the failure to achieve the 97% availability requirement, which is measured on a monthly basis (availability is calculated based on Bid Capacity and not nameplate capacity). Also, the EPA allows a Seller to generate surplus energy of up to 5% per hour, which can be used to offset some of the energy shortfalls during other hours.

44.0 Reference: CFT Report, Appendix B – Call for Tenders issued October 31, 2003, Appendix 1

1.44.2 Please provide industry benchmarks for the availability of the following types of supply sources:

- Large thermal (separate indicators for CT, co-generation and CCGT, and by component if applicable)
- Small thermal (separate indicators for CT, co-generation and CCGT, and by component if applicable)
- Large hydro
- Small hydro
- Micro hydro
- Wind
- Biomass
- HVDC (and various forms of HVDC, if available)
- Submarine cable (500 kV, 230 kV and HVDC)
- TM2500 Generators

RESPONSE:

Industry information is summarized from the following sources:

- **VIGP bidder information**
- **North American Electric Reliability Council (NERC)**
- **Canadian Electricity Association (CEA)**
- **CIGRE**

In terms of published industry data, it is difficult to identify directly comparable references since most such published data is provided on an annual basis whereas the CFT requirement is only for October through March. The additional maintenance opportunities during the rest of the year should provide for more reliable operation during the winter period.

Availability data also does not normally include the impact of intermittent resources that do not provide dependable capacity, such as wind energy. The data usually represents the generating equipment only and includes plants. The data includes plants that are not critical for providing dependable capacity and therefore are not maintained to the same standard as would be expected of the plants that would be built in response to a call for dependable capacity.

In addition, since most published data includes older units with generic problems that have since been fixed, it is reasonable to expect significantly better performance from the new units that would be built in response to the CFT.

The data for jet engines and gas turbines includes units used in simple-cycle configurations that are rarely economic to run and are therefore may not be well maintained.

<u>VI CFT Bidder Information</u>:

Following are some industry benchmarks from the CFT submissions and other sources that confirm that the 97% availability requirement for just the 9-month winter period is achievable:

- **The GE LM6000 Gas Turbine units have 97.8% documented availability based on five million operating hours (Source: http://www.gepower.com/prod_serv/products/aero_turbines/en/lm6000.htm).**
- **One bidder confirmed the GE claim that its model LM600 gas turbine has achieved 97.8% availability.**
- **One bidder provided information from a proprietary source, indicating that even some pioneering gas turbines achieved availabilities of at least 97%.**
- **One bidder provided references for three CCGT plants that all have average availabilities in excess of 97%.**
- **One bidder pointed to several BC Hydro hydroelectric plants and two other third-party hydroelectric plants as evidence that this technology could achieve the mandatory criteria.**

<u>NERC Availability Data</u>:

Data from the NERC Generating Availability Data (GAD) System (http://www.nerc.com/~filez/gar.html) is summarized in the following table. This data is based on performance over a full year of operation, not just during a critical peak load period. Also, this data would include older units with generic failure problems that have been eliminated in new units of similar design. A summary of NERC data is shown below in Table IR 1.44.2(a).

Table IR 1.44.2(a) NERC Generating Availability Data

Supply Source	Availability Factor	Forced Outage Rate
Jet Engine Units 1-19 MW	92.70%	46.47%
Jet Engine Units 20+ MW	91.98%	31.12%
Gas Turbine 1-19 MW	91.96%	55.80%
Gas Turbine 20-49 MW	93.20%	46.38%
Gas Turbine 50+ MW	91.01%	27.80%
Combined Cycle (all sizes)	89.00%	4.00%
Hydro 1-29 MW	88.82%	5.89%
Hydro 30+ MW	89.47%	3.94%
Coal-Fired Steam Turbine Generator 1-99 MW	87.45%	4.34%
Coal-Fired Steam Turbine Generator 100-199 MW	88.06%	4.41%
Coal-Fired Steam Turbine Generator 200-299 MW	87.49%	4.44%
Coal-Fired Steam Turbine Generator 300-399 MW	85.76%	5.09%
Coal-Fired Steam Turbine Generator 400-599 MW	85.80%	5.22%
Coal-Fired Steam Turbine Generator 600-799 MW	86.41%	4.89%
Coal-Fired Steam Turbine Generator 800-999 MW	86.53%	3.38%
Coal-Fired Steam Turbine Generator 1000+ MW	82.63%	8.10%

NERC does not differentiate between stand-alone generating units and those used in a co-generation configuration.

The following are the relevant NERC definitions used in the GAD system:

- **Available Hours (AH): Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH), and Maintenance Outage Hours (MOH).**
- **Period Hours (PH): Number of hours a unit was in the active state. A unit generally enters the active state on its service date.**
- **Service Hours (SH): Total number of hours a unit was electrically connected to the transmission system [and operating as a generator].**
- **Availability Factor (AF): (AH/PH)*100%**
- **Forced Outage Rate (FOR): [FOH/(FOH+SH+Synchronous condensing hours+Pumping hours)]*100%**

<u>CEA Availability Data</u>:

The CEA 2003 Generation Equipment Status Annual Report (http://www.canelect.ca/english/home.html) provides the following availability data for various generating units. See Table IR 1.44.2(b).

Table IR 1.44.2(b) CEA Generating Availability Data

Supply Source	Availability Factor	Forced Outage Rate
Hydraulic 5-23 MW	91.74%	3.41%
Hydraulic 24-99 MW	92.14%	1.58%
Hydraulic 100-199 MW	89.78%	1.06%
Hydraulic 200-299 MW	88.37%	2.03%
Hydraulic 300-399 MW	90.37%	1.06%
Hydraulic 400-499 MW	94.19%	0.17%
Hydraulic 500+ MW	92.25%	0.46%
Combustion Turbine Units 1-9 MW	53.67%	99.75%
Combustion Turbine Units 10-24 MW	99.16%	30.98%
Combustion Turbine Units 25-49 MW	87.46%	31.05%
Combustion Turbine Units 50+ MW	84.49%	14.81%

The CEA Generation Equipment Status Annual Report also provides data on the contributors to the combustion turbine Forced Outage Rate. See Table IR 1.44.2(c).

Table IR 1.44.2(c) CEA Forced Outage Data for Generating Equipment

Component	Contribution to Forced Outage Rate
Combustion Turbine	15.37%
Generator	3.27%
Instrumentation and Control	2.39%
Conditions	0.68%
Total:	21.71%

The CEA data doesn't differentiate between combustion turbines in simple-cycle, combined-cycle and cogeneration configurations.

BC Hydro was unable to find industry availability benchmark data for either micro hydro units or the TM2500 unit, although the availability of micro hydro generating equipment should be similar to that for small hydro plants, and the TM2500 data might be similar to that shown for jet engines, since the TM2500 is an "aeroderivative" type.

The April 2004 CEA Forced Outage Performance of Transmission Equipment report provides data on a 100 km-year basis for cables (the CEA data is not disaggregared into underground and submarine cables). See Table IR 1.44.2(d).

Table IR 1.44.2(d) CEA Unavailability Data for Transmission Equipment

Voltage Level	Unavailability
Up to 109 kV	0.548%
110-149 kV	3.068%
150-199 kV	0.000%
200-299 kV	8.831%
300-399 kV	5.240%
500-599 kV	0.067%

CIGRE Availability Data:

CIGRE (http://www.cigre.org/gb/indexie.htm) publishes HVDC reliability data every second year. However, this data is provided for each separate installation and the data is not summarized into overall average or expected performance. Attached is an article from a recent publication that describes the CIGRE HVDC reliability data.

A survey of HVDC reliability

How reliable are high voltage DC links? Data collected by CIGRE gives some of the answers.

I. Vancers, *Great River Valley, Minnesota, USA,* **M G Bennett,** *Teshmont Consultants, Winnipeg, Canada,* **D J Christofersen,** *CeCe, Minnesota, USA,* **A Leirbukt,** *ABB Consulting, Latham, NY, USA.*

Working Group 4 of Cigré (*Conseil International des Grands Réseaux Électriques*) study committee 14, now renamed 4B, was formed specifically to assemble and publish data on the reliability and operational experience of HVDC systems in service around the world. To this end it collects information annually from the operators of such systems, and at two year intervals, publishes it. The resulting report contains data on energy availability, energy utilisation, forced and scheduled outages and other data, in accordance with a standardised reporting protocol, as well as statistics on the frequency and duration of forced outages, for the years 1999 and 2000. Combined with previous data it also presents a cumulative average of forced outages by frequency and duration covering the years 1988 to 2000 and categorised by back-to-back stations and stations with one, and two or more, converters per pole.

The reporting protocol has been revised periodically as experience was gained in collecting and interpreting the data. The most recent revision was adopted in 1997 and can be obtained through Cigré's Paris HQ.

Data were first collected in 1968, covering four DC systems utilising mercury-arc valves. Data on the first thyristor valve system were compiled in 1972. This report covers 23 thyristor valve systems and five mercury-arc valve systems for operations during 1999-2000.

The accumulated data provide a continuous record of reliability performance of HVDC systems throughout the world during the 33 years following their first operation. For thyristor valve systems, which are of most interest to utilities that are considering HVDC transmission for their systems, the data represent approximately 440 system-years of operation over a period of 29 years. The working group also maintains a compendium containing the main data for all existing HVDC schemes. A copy can be obtained through Cigré.

HVDC reliability performance

The overall reliability statistics for all systems for which reports were received for 1999 and 2000 are given in Table 1. Six of the systems are back-to-back systems and the remainder are point-to-point transmission systems utilising overhead line and/or cable systems. A report was received for 1999 for Leyte-Luzon system but the data was not in the protocol format and is not included here.

Table 1 shows the maximum continuous transmission capacity, energy availability, energy utilisation and energy unavailability for the systems covered. Energy availability is a measure of the amount of energy that could have been transmitted over the HVDC system, except as limited by forced and scheduled outages of converter station equipment and DC transmission lines or cables. Energy utilisation is a measure of the amount of energy actually transmitted. Both parameters are expressed as a percentage based on the maximum continuous capacity of the HVDC system.

Table 1 shows that some systems operate at very low energy utilisation, ie they are used primarily for standby capacity, and other systems at very high energy utilisation, ie approaching maximum rated capacity.

Forced energy unavailability (FEU) is the amount of energy that, because of forced outages, could not have been transmitted over the DC system. Only converter station equipment outages are considered; transmission line and cable outages are excluded.

Scheduled energy unavailability (SEU) is the amount of energy that, because of scheduled outages, could not have been transmitted over the DC system. Although transmission line and cable scheduled outages are included in the data in Table 1, it is believed that in most cases the scheduled energy unavailability shown closely approximates that for converter stations only, since most scheduled maintenance on transmission lines and cables is conducted concurrently with station maintenance. Scheduled outages have less impact on the per-

Table 1. System energy availability, energy utilisation and converter station energy unavailability

System	Year commissioned	Maximum continuous capacity MW	Energy availability per cent		Energy utilisation per cent[1]		Forced energy unavailability per cent[2]		Scheduled eergy unavailability per cent	
			1999	2000	1999	2000	1999	2000	1999	2000
Skagerrak 1 & 2	1976/77	550	96.4	98.0	30.2	43.8	0.40	0.19	3.19	1.81
Skagerrak 3	1993	500	97.2	97.9	44.0	57.2	0.15	0.02	2.61	2.05
Vancouver Island Pole 2	1977/79	550	91.7	77.2	66.4	53.6	0.64	1.23	7.61	21.58
Square Butte	1977	550	95.9	94.8	78.9	77.0	0.10	0.38	2.37	4.44
Shin-Shinano 1	1977	300	98.7	98.0	4.3	0.01	0.00	0.00	1.27	2.04
Shin-Shinano 2	1992	300	90.9	99.1	11.7	8.1	0.00	0.00	9.09	0.91
Nelson River BP1[3]	1973/93	835	76.5	92.4	51.2	68.0	22.9	7.12	0.56	0.50
Nelson River BP2	1978/83	2000	93.4	87.8	60.4	63.8	2.38	10.1	4.26	2.08
Hokkaido-Honshu	1979/93	600	97.1	90.4	11.9	10.4	0.00	0.04	2.92	7.34
CU	1979	1138	97.0	99.5	71.7	76.3	0.04	0.15	2.96	0.38
Gotland 2 & 3	1983/87	320	99.6	98.7	27.7	28.9	0.01	0.81	0.40	0.52
Itaipu BP1	1985/86	3150	97.2	97.7	78.0	77.4	0.22	0.05	2.55	2.24
Itaipu BP2	1985/86	3150	98.0	97.3	78.0	77.4	0.71	0.05	1.28	2.64
Highgate	1985	200	98.3	100.0	81.6	79.0	0.09	0.00	1.60	0.01
Cross Channel Bipole 1	1985/86	1000	96.1	95.5	85.9	82.1	0.01	2.73	3.86	1.80
Cross Channel Bipole 2	1986	1000	96.2	97.9	86.1	83.0	0.06	0.22	3.71	1.91
Virginia Smith	1988	200	73.8	97.5	24.2	64.7	17.6	0.18	8.61	2.36
Konti Skan 2	1988	300	98.1	97.2	22.0	43.1	0.10	1.01	1.81	1.76
McNeill	1989	150	95.7	95.5	47.9	61.1	0.82	0.38	3.50	4.10
Fennoskan	1990	500	98.4	97.9	32.0	45.0	0.04	0.65	1.59	1.49
SACOI[4]	1992	300/300/50	86.1	93.2	37.9	42.4	0.29	0.20	9.07	5.69
New Zealand Pole 2[3]	1992	500	98.5	98.4	48.8	57.9	0.03	0.08	1.20	1.49
Sakuma	1965/93	300	91.6	98.0	2.0	0.4	0.35	0.15	8.00	1.90
Mercury-arc valves										
Konti Skan 1	1965	275	97.9	97.7	20.8	49.5	0.31	0.14	1.84	2.18
New Zealand Pole 1	1965/92	500	94.6	95.4	32.7	40.9	0.72	0.87	4.27	3.75
Vancouver Island Pole 1	1968/69	312	76.3	37.4	58.1	4.8	12.9	1.47	10.9	61.12
Pacific Intertie	1970/89	3100[5]	88.0	88.9	40.5	31.9	2.87	1.70	8.90	9.40
Nelson River BP1 Pole 2	1973/77	835	95.3	95.4	51.2	68.0	2.43	1.66	2.28	2.97

Notes (1) Based on maximum continuous capacity (2) Converter station outages only (3) Thyristor pole (4) Three terminal monopole system (5) Includes capacity of thyristor valve groups

Table 2A. Number of forced outages and equivalent outage hours, 1999

System	AC-E No.	AC-E Hours	V No.	V Hours	C & P No.	C & P Hours	DC-E No.	DC-E Hours	O No.	O Hours	TL No.	TL Hours	TOTAL No.	TOTAL Hours
Skagerrak 1 & 2	1	1.8	0	0.0	2	24.7	1	8.7	2	0.3	1	1.1	7	36.5
Skagerrak 3	8	12.8	0	0.0	0	0.0	0	0.0	1	0.1	1	5.7	10	18.6
Vancouver Island Pole 2	2	1.6	0	0.0	1	0.0	4	54.7	0	0.0	1	3.8	8	60.2
Square Butte	4	7.9	1	0.8	1	0.1	0	0.0	0	0.0	11	143.4	17	152.2
Shin-Shinano 1	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	-	-	0	0.0
Shin-Shinano 2	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	-	-	0	0.0
Nelson River BP1 Pole 1	11	1996.4[1]	0	0.0	2	0.8	5	3.3	7	4.8	0	0.0	25	2005.3
Nelson River BP2	10	191.0	9	5.7	3	3.5	6	1.8	5	6.3	0	0.0	33	208.3
Hokkaido-Honshu	0	0.0	0	0.0	1	0.3	0	0.0	0	0.0	0	0.0	1	0.3
CU	2	1.4	0	0.0	2	1.8	0	0.0	1	0.1	0	0.0	5	3.3
Gotland 2 & 3	1	0.4	0	0.0	0	0.0	0	0.0	1	0.5	0	0.0	2	0.9
Itaipu BP1	1	10.4	0	0.0	1	0.0	4	8.5	1	0.4	0	0.0	7	19.3
Itaipu BP2	2	42.5	0	0.0	10	11.7	3	5.8	2	2.4	2	0.1	19	62.4
Highgate	1	7.7	0	0.0	0	0.0	0	0.0	0	0.0	-	-	1	7.7
Cross Channel Bipole 1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.5	0	0.0	1	0.5
Cross Channel Bipole 2	4	3.9	0	0.0	0	0.0	0	0.0	1	1.0	0	0.0	5	4.9
Virginia Smith	3	1536.9[2]	7	1.0	2	3.2	0	0.0	1	0.3	-	-	13	1541.4
Konti Skan 2	0	0.0	0	0.0	4	2.7	2	6.1	0	0.0	0	0.0	6	8.9
McNeill	0	0.0	2	59.2	2	12.3	0	0.0	0	0.0	-	-	4	71.5
Fennoskan	0	0.0	1	1.1	0	0.0	2	1.7	1	0.5	0	0.0	4	3.3
SACOI	9	21.3	1	0.2	5	4.1	0	0.0	0	0.0	35	399.9	50	425.4
New Zealand Pole 2	0	0.0	0	0.0	3	2.4	0	0.0	0	0.0	1	24.4	4	26.8
Sakuma	0	0.0	0	0.0	1	30.7	0	0.0	0	0.0	-	-	1	30.7

***Notes** (1) Converter transformer failure (2) Converter transformer bushing failure.*

Table 2B. Forced outages and equivalent outage hours, 2000

System	AC-E No.	AC-E Hours	V No.	V Hours	C & P No.	C & P Hours	DC-E No.	DC-E Hours	O No.	O Hours	TL No.	TL Hours	TOTAL No.	TOTAL Hours
Skagerrak 1 & 2	2	9.8	0	0.0	0	0.0	2	6.5	0	0.0	0	0.0	4	16.3
Skagerrak 3	2	2.2	0	0.0	0	0.0	0	0.0	0	0.0	2	1.9	4	4.0
Vancouver Island Pole 2	1	0.5	3	10.0	1	11.0	3	86.2	0	0.0	0	0.0	8	107.8
Square Butte	2	10.9	0	0.0	1	0.5	2	17.0	3	4.9	2	30.7	10	64.0
Shin-Shinano 1	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	-	-	0	0.0
Shin-Shinano 2	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	-	-	0	0.0
Nelson River BP1 Pole 1	4	608.8[1]	1	2.5	1	0.0	5	10.2	2	2.2	0	0.0	13	623.8
Nelson River BP2	30	865.6[1]	9	7.8	3	8.1	6	2.4	3	0.6	2	0.0	53	884.5
Hokkaido-Honshu	0	0.0	0	0.0	1	3.5	0	0.0	0	0.0	2	190.9	3	194.4
CU	0	0.0	0	0.0	6	5.6	1	7.5	0	0.0	0	0.0	7	13.1
Gotland 2 & 3	0	0.0	2	71.3	0	0.0	0	0.0	0	0.0	0	0.0	2	71.3
Itaipu BP1	3	3.4	0	0.0	1	0.4	0	0.0	3	0.4	2	0.0	9	4.2
Itaipu BP2	2	1.6	0	0.0	2	2.3	0	0.0	2	0.3	0	0.0	6	4.1
Highgate	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	-	-	0	0.0
Cross Channel Bipole 1	6	230.1[2]	2	8.5	0	0.0	1	0.8	0	0.0	0	0.0	9	239.5
Cross Channel Bipole 2	2	3.6	1	2.0	3	11.1	1	2.3	0	0.0	0	0.0	7	19.0
Virginia Smith	3	1.4	1	4.1	0	0.0	0	0.0	2	10.4	-	-	6	16.0
Konti Skan 2	3	63.5	0	0.0	4	24.8	0	0.0	0	0.0	0	0.0	7	88.4
McNeill	2	22.2	1	1.5	0	0.0	0	0.0	3	9.4	-	-	6	33.1
Fennoskan	2	13.5	0	0.0	1	43.3	0	0.0	0	0.0	0	0.0	3	56.8
SACOI	11	15.6	0	0.0	6	2.2	0	0.0	0	0.0	31	77.0	48	94.8
New Zealand Pole 2	0	0.0	0	0.0	2	6.7	0	0.0	0	0.0	3	1.0	5	7.7
Sakuma	1	12.9	0	0.0	0	0.0	0	0.0	0	0.0	-	-	1	12.9

*Key: AC-E – AC and auxiliary equipment; V – Valves; C&P – Control and protection; DC-E – DC equipment; O – Other; TL – Transmission line or cable. **Notes** (1) Converter transformer failure (2) Converter transformer bushings*

formance of the power system than forced outages since planned outages can usually be taken during periods of reduced system load or when some reduction in transmission capacity can be accepted. Hence scheduled energy unavailability can vary substantially from system to system owing to differences in utility maintenance practices and policies, and the requirement for transmission capacity.

Forced outage data

Data on forced outages are given in Tables 2 and 3. Data are classified into six categories by equipment type.

The number of forced outage events and the equivalent forced outage hours within each category, together with the totals for each DC system, are shown in Tables 2A and 2B. 'Equivalent forced outage hours' is the sum of the actual forced outage hours after the outage duration has been adjusted for the percentage reduction in capacity owing to the outage. For example, for an outage of one pole of a bipole system (50 per cent loss of capacity) which lasted two hours, the equivalent outage hours would be one.

The protocol separates out reporting events which caused a reduction in transmission capacity but did not lead to a forced trip of the HVDC equipment. Table 2C summarises capacity reductions included in the statistics reported in Tables 2A and 2B. Capacity reductions are not included in the values reported in Tables 3 to 5 as these outages did not lead to a forced trip of equipment.

Table 2C. Number of capacity reductions and equivalent outage hours[1]

System	1999 No.	1999 Hours	2000 No.	2000 Hours
Skaggerak 3	-	-	2	1.9
Vancouver island pole2	1	1.4	-	-
Nelson River BP1 pole 1	1	2.9	2	1.3
Nelson River BP2	3	141.9	8	728.4
Cross Channel bipole 1	-	-	1	2.6
New Zealand pole 2	-	-	1	6.3

Note: (1) Outage statistics includedin Tables 2A and 2B.

Approximately 89 per cent of all forced outages in 1999 and 2000 were attributed to equipment on the AC side of the converters. This compares to about 7 per cent of all forced outages attributed to the major DC equipment (valves 3 per cent, other DC equipment 4 per cent). Control and protections account for 3 per cent of the outages and "other" causes, which includes human error, account for 1 per cent. The large proportion of FEU for AC equipment is attributable to the converter transformer outages which occurred in 1999 and 2000.

Frequency and duration

Table 3 shows the frequency and duration of forced outages and the cumulative average of this data from 1988 to 2000. Table A covers back-to-back converter stations, B covers systems with one converter per pole, and C covers systems with two or more series-connected converters per pole. The data for systems reporting operation of less than one full year has been adjusted in these tables to an annual basis for the year, but the cumulative average is calculated for the actual reporting period.

Table 3A shows the average frequency (number) and average duration of station outages for back-to-back converter stations. Tables 3B and 3C show the average frequency and duration of converter, pole and bipole outages for two-terminal and multi-terminal systems. The frequency of outages is given on a per terminal basis. The data contained in Table 3 in particular should be of value to planning engineers using HVDC reliability studies.

Thyristor valve performance

Data on thyristor failure rates are given in Table 4, which shows the number of failed cells in 1999 and 2000 for each of the DC systems for which data were provided.

A thyristor cell is an individual thyristor (with its associated auxiliary circuits) while a thyristor level is the assembly of one or more thyristor cells connected in parallel. A number of thyristor levels connected in series forms a valve.

The thyristor cell failure rate is the ratio of the number of cell failures to the total number of cells in the system and is an indication of the inherent failure rate of the thyristors and their associated circuitry. In most cases the thyristor cell failure rate is well below 0.5 per cent.

The commutation failure start rate is shown in Table 5. CFS are usually caused by AC system voltage disturbances (see recordable AC fault column) but may be internal to the converter station. More frequent CFS could be indicative of valve and control system problems.

Table 3A. Frequency and duration of forced outages – back-to-back converter stations

System	1999 f_s	1999 d_s	2000 f_s	2000 d_s	Average to 2000 Years	Average to 2000 f_s	Average to 2000 d_s
Shin-Shinano1	0.00	0.0	0.00	0.0	11	0.73	1.1
Shin-Shinano 2	0.00	0.0	0.00	0.0	7.6	0.39	0.2
Highgate	1.00	7.7	0.00	0.0	12	2.00	10.2
Virginia Smith	13.00	118.6	6.00	2.7	11	5.27	29.2
McNeill	4.00	17.9	6.00	5.5	7	9.57	6.2
Sakuma	1.00	30.7	1.00	12.9	7.5	0.67	17.1

Key to Table 3

f_s number of station outages per block for back-to-back converter stations per year

f_c number of converter outages per converter per terminal per year

f_p number of pole outages per pole per terminal per year

f_b = number of bipole outages per bipole per terminal per year

d_s average duration of station outages in hours

d_c average duration of converter outages in hours

d_p average duration of pole outages in hours

d_b average duration of bipole outages in hours

These systems are all a single independent back-to-back converter circuit consisting of one rectifier and one inverter.

Table 3B. Frequency and duration of forced outages – 2 terminal systems, 1 converter per pole

System	1999 Pole f_p	1999 Pole d_p	1999 Bipole f_b	1999 Bipole d_b	2000 Pole f_p	2000 Pole d_p	2000 Bipole f_b	2000 Bipole d_b	Average to 2000 Years	Average to 2000 Pole f_p	Average to 2000 Pole d_p	Average to 2000 Bipole f_b	Average to 2000 Bipole d_b
Skagerrak 1 & 2	1.50	11.8	0.00	0.0	0.75	9.3	0.50	2.4	12	1.94	19.2	0.17	1.0
Skagerrak 3[1]	4.50	1.4	-	-	1.00	1.1	-	-	7	1.71	1.6	-	-
Square Butte	1.50	2.9	0.00	0.0	1.75	8.4	0.50	3.9	10	3.08	7.3	0.35	1.5
CU	1.25	1.3	0.00	0.0	1.75	3.7	0.00	0.0	12	2.13	2.0	0.21	2.7
Gotland 2 & 3	0.50	0.9	0.00	0.0	0.50	71.3	0.00	0.0	12	0.33	17.7	0.29	1.2
Cross Channel Bipole 1	0.00	0.0	0.50	0.5	1.50	77.3	1.00	2.5	12	0.60	29.8	2.92	3.0
Cross Channel Bipole 2	0.00	0.0	2.50	1.0	1.00	3.9	1.50	3.8	12	0.42	5.1	2.92	5.7
Konti Skan 2[1]	3.00	1.5	-	-	3.50	12.6	-	-	12	3.29	3.1	-	-
Fennoskan[1]	2.00	0.8	-	-	1.50	18.9	-	-	11	3.18	6.1	-	-
SACOI[2]	5.00	1.7	-	-	5.67	1.0	-	-	8	4.79	2.7	-	-
New Zealand Pole 2[3]	1.50	0.8	-	-	0.50	0.4	-	-	9	1.83	2.6	-	-

Notes (1) Monopolar System (2) Three terminal monopolar system (3) One pole

Table 3C. Frequency and duration of forced outages – 2 terminal systems, two or more converters per pole

System	1999 Converter f_c	1999 Converter d_c	1999 Pole f_p	1999 Pole d_p	1999 Bipole f_b	1999 Bipole d_b	2000 Converter f_c	2000 Converter dc	2000 Pole f_p	2000 Pole d_p	2000 Bipole f_b	2000 Bipole d_b	Average to 2000 Years	Average to 2000 f_c	Average to 2000 d_c	Average to 2000 f_p	Average to 2000 d_p	Average to 2000 f_b	Average to 2000 d_b
Vancouver Pole 2[1]	1.00	1.9	1.00	25.6	-	-	1.50	11.0	1.00	37.5	-	-	9	1.64	32.6	1.50	5.7	-	-
Nelson River BP1 Pole[1]	3.67	273.0	1.00	0.3	-	-	1.33	230.1	1.50	3.0	-	-	5	1.97	350.2	1.40	0.9	-	-
Nelson River BP2	2.75	10.6	2.00	2.0	0.00	0.0	4.38	16.0	2.25	3.5	0.00	0.0	12	3.99	23.6	2.17	2.6	0.25	3.8
Hokkaido-Honshu[2]	0.00	0.0	0.25	0.6	0.00	0.0	0.00	0.0	0.25	7.1	0.00	0.0	12[3]	0.04	23.4	0.46	3.3	0.06	324.5
Itaipu BP1	0.38	16.2	0.75	4.5	0.50	0.4	0.63	2.9	0.50	0.5	0.00	0.0	12	17.7		0.73	7.2	0.17	1.3
Itaipu BP2	1.38	20.3	1.50	2.2	0.00	0.0	0.63	3.3	0.25	0.1	0.00	0.0	12	1.62	72.7	1.17	2.0	0.08	3.6

Notes: (1) One pole only (2) Two converters in first pole, one in second pole (3) 7.8 years bipolar operation

Table 4. Thyristor calendar failure rate

System	Total levels	Total cells	Number of failed cells 1999	Number of failed cells 2000	Thyristor cell failure rate per cent/year[1] 1999	Thyristor cell failure rate per cent/year[1] 2000
Skagerrak 1 & 2	6912	6912	16	20	0.23	0.29
Skagerrak 3	1440	1440	0	4	0.00	0.28
Vancouver Island Pole 2	4320	8640	2	2	0.02	0.02
Square Butte	6912	6912	6	9	0.09	0.13
Shin-Shinano 1	3744	5184	2	0	0.04	0.00
Shin-Shinano 2	672	672	0	0	0.00	0.00
Nelson River BP1 Pole 1	2952	2952	2	0	0.07	0.00
Nelson River BP2	9216	18432	21	8	0.11	0.04
Hokkaido-Honshu	4008	4008	0	0	0.00	0.00
CU	8640	8640	16	34	0.19	0.39
Gotland 2 & 3	864	864	0	13	0.00	1.50
Highgate	432	432	0	0	0.00	0.00
Cross Channel Bipole 1	5304	10608	27[2]	32[2]	0.25	0.30
Cross Channel Bipole 2	5304	10608	24[2]	18[2]	0.23	0.17
Virginia Smith	960	960	0	0	0.00	0.00
Konti Skan 2	1152	1152	0	0	0.00	0.00
McNeill	276	276	1	1	0.36	0.36
Fennoskan	1584	1584	0	0	0.00	0.00
SACOI1	1344	1344	4	8	0.30	0.60
New Zealand Pole 2	1584	1584	0	0	0.00	0.00
Sakuma	672	672	0	0	0.00	0.00

Notes (1) Suverto & Codrongianos terminals only (2) Majority of failures at Les Mandarins terminal.

Table 5. AC faults and commutation failure starts

System	1999 Recordable AC faults	1999 Number of CFS External	1999 Number of CFS Internal	2000 Recordable AC faults	2000 Number of CFS External	2000 Number of CFS Internal
Skagerrak 1 & 2	12	12	7	38	16	11
Skagerrak 3	13	17	4	38	16	2
Vancouver Island Pole 2	-	78	2	-	12	4
Square Butte	19	11	-	15	10	-
Shin-Shinano 1	0	0	0	0	0	0
Shin-Shinano 2	11	0	1	0	0	0
Nelson River BP1 Pole 1	5	29	206	12	155	251
Nelson River BP2	5	11	20	12	58	67
Hokkaido-Honshu	21	5	-	24	9	-
CU	10	6	3	8	11	3
Gotland 2 & 3	11	11	0	4	4	0
Highgate	10	15	0	19	11	-
Cross Channel Bipole 1	29	56	4	32	41	24
Cross Channel Bipole 2	26	48	8	26	38	10
Virginia Smith	2	2	0	0	0	0
Konti Skan 2	0	4	0	0	18	0
McNeill	-	-	-	0	0	0
Fennoskan	40	2	4	0	0	12
SACOI1	0	0	30	0	4	69
New Zealand Pole 2	8	4	2	6	3	2
Sakuma	0	0	0	0	0	0

44.0 Reference: CFT Report, Appendix B – Call for Tenders issued October 31, 2003, Appendix 1

1.44.3 Is there any requirement for guaranteed availability during the period of April to September? If so, please describe that requirement.

RESPONSE:

The Seller is required to guarantee an availability of 97% during April to September, the same as during the period of October to March. However, the Seller is permitted to perform Scheduled Planned Outages during the months of April, May and June.