

Independent Power Producers of B.C. Information Request No. 3.1.1 Dated: September 8, 2006 British Columbia Hydro & Power Authority Response issued September 29, 2006	Page 1
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1.0 Reference: Exhibit B-15, page 5, Table 1

- 3.1.1 Please give a more detailed breakdown by components for the lines showing significant variances between Plan and Update, namely Cost of Energy, Finance Charges, Trade Income, and Inter-Segment Revenues. Please include F2007 Plan and Update and F2008 Plan and Update, by components.

RESPONSE:

The detailed breakdown by components for Cost of Energy, Finance Charges, and Inter-Segment Revenues is provided in the attached schedules. Further detail regarding Trade Income has not been provided for reasons explained in the response to BCUC IR 1.13.0.

Domestic Cost of Energy, Volume and Cost/MWh, F2007 and F2008 - Plan versus Update

	A	B	C	D	E	F
(\$ million)	F2007 Plan	F2007 Update	F2008 Plan	F2008 Update	F2007 Variance	F2008 Variance
Heritage Energy:						
Hydroelectric (water rentals)	273	269	296	300	(4)	4
Market electricity purchases	321	269	230	238	(52)	8
Market electricity purchases transfer to Non-Heritage	(114)	(101)	(144)	(159)	13	(15)
Natural gas for thermal generation ¹	32	36	33	32	4	(1)
Domestic transmission	16	16	17	15	-	(2)
Other	3	4	(12)	(5)	1	7
	531	493	420	422	(38)	1
Non-Heritage Energy:						
IPP's and long-term purchase commitments	452	429	512	501	(23)	(11)
Market electricity purchases transfer from Heritage	114	101	144	159	(13)	15
Non-Integrated Areas	19	19	20	21	-	1
Gas and other transportation	10	11	10	12	1	2
Domestic transmission	71	71	70	70	-	-
Net purchases from Powerex	-	-	-	-	-	-
	666	631	756	763	(35)	7
Total Domestic cost of energy	1,197	1,124	1,176	1,184	(73)	8
Source of Supply (GWh)						
Heritage Energy:						
Hydroelectric (water rentals)	46,843	45,746	48,352	49,252	(1,097)	900
Net sales to Powerex (displaced hydro generation)	(1,248)	(465)	(952)	(1,757)	783	(805)
Market electricity purchases	5,999	5,616	3,605	3,586	(383)	(19)
Natural gas for thermal generation	222	326	191	183	104	(8)
Exchange net	(681)	(118)	57	132	563	75
Market electricity purchases transfer to Non-Heritage	(2,134)	(2,105)	(2,253)	(2,396)	29	(143)
	49,000	49,000	49,000	49,000	-	-
Non-Heritage Energy:						
Market electricity purchases transfer from Heritage	2,134	2,105	2,253	2,396	(29)	143
IPP's and long-term purchase commitments	7,208	6,953	7,861	7,718	(255)	(143)
Non-integrated areas	109	109	111	111	-	-
	9,451	9,167	10,225	10,225	(284)	-
Total Sources of supply	58,451	58,167	59,224	59,224	(284)	-
Less:						
Line loss and system use	(5,309)	(5,025)	(5,382)	(5,382)	284	-
Domestic Sales Volumes	53,142	53,142	53,842	53,843	-	-
(\$/MWh)						
Hydroelectric (water rentals)	5.8	5.9	6.1	6.1	0.1	-
IPP's and long-term purchase commitments	62.7	61.7	65.1	64.9	(1.0)	(0.2)
Market electricity purchases	53.4	48.0	63.9	66.4	(5.4)	2.5
Net Purchases from Powerex						
Natural gas for thermal generation	146.1	110.0	173.7	174.2	(36.1)	0.5
Domestic cost of energy - Non-Integrated Areas	170.6	176.7	176.3	185.4	6.1	9.1
Total weighted average cost ²	22.5	21.1	21.8	22.0	(1.4)	0.2

Notes:

- This includes fixed transportation costs of approximately \$10 million related to the Bypass Transportation Agreement between Terasen Gas Inc. and BC Hydro.
- Calculated as total cost divided by sales volumes.
- Schedules/tables may not add due to minor computer rounding.

Finance Charges, F2007 and F2008 - Plan versus Update

	A	B	C	D	E	F
1 (\$ million)	F2007	F2007	F2008	F2008	F2007	F2008
2	Plan	Update	Plan	Update	Variance	Variance
3 Finance Charges						
4 Interest on Debt Securities						
5 - bonds, notes and debentures	491	488	488	482	(3)	(6)
6 - revolving borrowings	35	27	53	51	(8)	(2)
7 Amortization of deferred debt costs and other expenses	24	15	25	25	(9)	-
8	549	530	566	558	(20)	(8)
9 Less:						
10 Sinking fund income	(41)	(41)	(31)	(34)	-	(3)
11 Other income	4	(1)	2	1	(5)	(1)
12 Finance charges capitalized to unfinished construction	(20)	(19)	(28)	(28)	1	-
13 Interest on deferral accounts	(18)	(13)	(16)	(9)	5	7
14	(74)	(74)	(74)	(70)	1	3
15 Total	475	456	492	488	(19)	(5)

18 Notes:

19 1 Schedules/tables may not add due to minor computer rounding.

**IPPBC IR 3.1.1
Attachment 3**

Inter-Segment Revenues, F2007 and F2008 - Plan versus Update

	A	B	C	D	E	F
1 (\$ million)	F2007	F2007	F2008	F2008	F2007	F2008
2	Plan	Update	Plan	Update	Variance	Variance
3 Net sales to Powerex - Future Use	42	4	54	92	(38)	38
4 Point-to-point wheeling charge to Powerex	31	31	29	29	-	-
5 Point-to-point wheeling charge to BC Hydro	23	23	21	21	-	-
6 Allocation of BC Hydro corporate costs to Powerex	5	5	4	4	-	-
7 Mark to Market Gains on Energy Derivatives with Powerex	-	(4)	-	-	(4)	-
8 Other	-	-	-	-	-	-
9 Total Inter-Segment Revenues	101	59	108	146	(42)	38
10						

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2.0 Reference: Exhibit B-15, page 7, Table 3

3.2.1 Please explain the term “net exchange”. How much of the Hydroelectric generation is due to “net exchange”?

RESPONSE:

Please refer to the response to BCUC IR 1.122.0 for an explanation of “exchange net”.

For the July 2006 energy study, which was the basis for the Evidentiary Update, forecast net exchanges were 118 GWh of net exports for F2007 and 132 GWh of net imports for F2008.

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2.0 Reference: Exhibit B-15, page 7, Table 3

3.2.2 What is the difference between the F2007 Plan and the F2007 Update, in terms of reservoir inflows as a percentage of normal?

RESPONSE:

Please refer to the response to BCUC IR 3.21.2.

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2.0 Reference: Exhibit B-15, page 7, Table 3

3.2.3 Please explain why the forecast for Powerex Net Sales has been reduced by 63% after only 3 months of actuals.

RESPONSE:

Please refer to the response to BCUC IR 3.10.1.

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3.0 Reference: Exhibit B-15, page 8, Table 4

- 3.3.1 Please explain why the forecast for Powerex Net Sales revenues has been reduced by 90% after only 3 months of actuals, and why the offsetting reversal is forecast for 2008. Please demonstrate how the changing power price forecasts relate to these net sales forecasts.

RESPONSE:

Please refer to the response to BCUC IR 3.10.1.

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4.0 Reference: Exhibit B-15, page 12, Tables 7 and 8

3.4.1 How are the Deferral Account Balances being financed by BC Hydro?

RESPONSE:

The deferral account balances either increase or decrease BC Hydro's total debt requirements (depending on whether the deferral account balances are positive or negative).

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4.0 Reference: Exhibit B-15, page 12, Tables 7 and 8

3.4.2 What is the rationale for the interest rates being charged on Deferral Account balances?

RESPONSE:

Please refer to the response to BCUC IR 2.364.0.

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4.0 Reference: Exhibit B-15, page 12, Tables 7 and 8

3.4.3 In the absence of the \$89 million of revenue that is surplus to the revised Revenue Requirement for F2007 (caused by the 4.65% rate increase being made effective July 1, 2006), would there have been zero recovery showing in Table 8 for F2007?

RESPONSE:

Yes.

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5.0 Reference: Exhibit B-15, page 16, Section 4 Capital Expenditures

- 3.5.1 The Aberfeldie schedule published in the August 31 Amended LTAP states that equipment and civil contracts have been awarded in April and June 2006 respectively. If so, please provide an update of the complete project costs and a comparison to the previous budget estimates. Has there been an updated business case presented for management approval since the April 20, 2006 Aberfeldie workshop presentation? If so, please provide the updated material.

RESPONSE:

Please refer to the response to BCUC IR 3.11.3.

Neither the equipment nor the civil contracts have been awarded as of the date of this response. No updated business case has been presented to management since the April 20, 2006 workshop. Based on the outcome of the civil tenders and updated cost and schedule information, an updated business case for the redevelopment of Aberfeldie may be presented for further management approval.

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5.0 Reference: Exhibit B-15, page 16, Section 4 Capital Expenditures

3.5.2 Section 4 states that \$22 million of capital expenditures has been shifted from F2007 into F2008 and F2009, and a further \$64 million has been shifted from F2008 into F2009. Does this mean that the total project cost is now in excess of \$85 million? If so, please confirm the exact amount of the new cost estimate and give the breakdown and timing of the expenditures. If not, please explain.

RESPONSE:

Please refer to the response to BCUC IR 3.11.2.

Table 12 of the Evidentiary Update indicates that \$23 million of capital expenditure has been deferred from F2007 to F2008 and F2009, due to the delay in the project.

This does not mean the project cost is now in excess of \$85 million.

Please also refer to the response to BCUC IR 3.11.3.

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5.0 Reference: Exhibit B-15, page 16, Section 4 Capital Expenditures

3.5.3 If the expansion were not proceeded with, what would be involved in decommissioning the Aberfeldie facility, and what is the cost estimate for that decommissioning? If the plant were decommissioned, instead of expanded, would it still require the maximum level of seismic protection for the decommissioned dam? If not, what level of seismic protection would be required?

RESPONSE:

Please refer to the response to BCUC IR 3.11.3.

Decommissioning of the Aberfeldie facility would involve the removal of the entire water conveyance system, including the woodstave penstock, the surge shaft structure and the high pressure steel penstock to the powerhouse. The powerhouse and switchyard would also be decommissioned and removed. The only structure which would be left in place would be the Aberfeldie intake dam, for which removal would not be practical or economic.

The cost for decommissioning and removal was estimated in 2004 at \$2.7 million. This cost estimate has not been updated since 2004 and does not reflect the issues included in updates for the redevelopment or more recent market changes.

In the case of decommissioning, the Aberfeldie intake dam would still remain the responsibility of BC Hydro. The consequence of failure of the dam due to seismic stability issues would not change. Therefore, the current level of seismic safety would have to be maintained and any future changes to seismic safety criteria would have to be addressed by BC Hydro in future dam safety reviews.

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6.0 Reference: Exhibit B-15, Attachment 2, Natural Gas and Electricity Price Forecasts

3.6.1 Please explain the term “BCB” for both Purchases and Sales. If this refers to BC border, then how do these prices relate to an index like Mid-C?

RESPONSE:

“BCB” refers to BC border. These prices are based on the Mid-C price forecast adjusted for the cost of transmission (wheeling) and losses from Mid-C to the BC border. Sale prices are based on the Mid-C price less the cost of transmission and losses incurred to deliver the electricity from the BC border to Mid-C while the purchase prices are based on the Mid-C price plus the cost of transmission and losses incurred to deliver the electricity from Mid-C to the BC border.

Transmission is forecast to be USD \$4.34/MWh while losses are 1.9% of the Mid-C price.

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6.0 Reference: Exhibit B-15, Attachment 2, Natural Gas and Electricity Price Forecasts

- 3.6.2 Please explain how the difference between the Purchase and Sale price is calculated. Is this purely the wheeling cost and losses between the border and Mid-C? Please give the costs expected over the F2007 and F2008 periods.

RESPONSE:

Please see the response to IPPBC IR 3.6.1.

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6.0 Reference: Exhibit B-15, Attachment 2, Natural Gas and Electricity Price Forecasts

- 3.6.3 If Mid-C (or some other index) is the underlying price forecast, please provide the complete methodology by which these forecasts are calculated. Are these forecasts based exclusively on the Sumas Gas Price? If not, then what other assumptions are also included in the calculations? What was the source of the Sumas Gas Price forecast?

RESPONSE:

Please see the response to BCUC IR 1.315.2. Note that BC Hydro references to “Mid-C” are references to the Mid-C trading hub not, for example, the Dow Jones Mid-C indices, unless expressly stated.

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7.0 Reference: Exhibit B-15, Attachment 5, Annual Audit Plan, pages 7 to 9

3.7.1 The table in Section 3, page 7, describes quarterly and annual reports by the Chief Risk Officer, of the overall BC Hydro risks. Please provide copies of the most recent annual report and the four most recent quarterly Risk Dashboards.

RESPONSE:

The four most recent quarterly “Risk Dashboards” and the risk assessment, prepared annually are attached.

BC Hydro has redacted certain information from the Risk Dashboards for the following reasons:

- **It is confidential customer information;**
- **It is privileged; or**
- **It is related to Powerex.**

BC Hydro Risk Dashboard

As Assessed at End of Q2 FY2006

Risk	Drivers	Prob-ability	Consequence				
			Financial	Safety	Environment	Reliability	People
1. Commodity - Domestic	<ul style="list-style-type: none"> ↑ Columbia discharge and Peace ice constraints may require Q1 purchases ↑ Significantly higher gas and electricity pricing ↑ Above plan industrial load further increases market exposure 	M	H		H		
2. Commodity -Trade		M	H				
3. Exchange Rate	<ul style="list-style-type: none"> ↓ Reduced EaR and USD exposure ↓ Hedging of USD debt principal now complete 	H	M				
4. Interest Rate	↑ Increasing variable rate debt and EaR	H	M				
5. Credit	↑ Declining credit quality in forestry sector	H	L				
6. Pension Fund	↓ Improved fund performance	M	H				
7. Dam Safety	→ Interim risk reduction measures in progress on Campbell River System and at Ruskin	L	E	E	H	H	
8. Generation Asset	→ Ageing equipment, new equipment, outages and failures	M	H	H	H	M	
9. Customer Reliability	↑ Premature failure of autosplices presents financial and safety risk	M	M	H		H	
10. Reliability of Supply	↑ Winter capacity planning underway; additional firm resources required	M	H				
11. Human Resources	<ul style="list-style-type: none"> ↑ Safety performance ↑ High level of unfilled vacancies 	M	M	H		M	H
12. Environment	<ul style="list-style-type: none"> ↑ Kyoto implementation → IEP / future supply portfolio choices 	M	M		H		
13. First Nations	<ul style="list-style-type: none"> ↑ Increased focus on VI cable, Site C ↑ Provincial First Nations accord may increase expectations 	M	H			H	
14. Regulatory		M	H		H	H	M

Legend: L = Low, M = Medium, H = High, E = Extreme, ↑ = Driver contributed to an increase in risk, ↓ = Driver contributed to a decrease in risk

BC Hydro Risk Dashboard

As Assessed at End of Q3 FY2006

Risk	Drivers	Prob-ability	Consequence				
			Financial	Safety	Environment	Reliability	People
1. Commodity - Domestic	<ul style="list-style-type: none"> ↑ Total system inflow forecast for FY07 is 3,900 GWH below normal ↑ Above plan industrial load further increases the system energy deficit ↓ Due to planned aggressive purchases, above normal storage levels before the freshet period, during which the below normal forecast inflows will be realized ↓ Forecast cost of energy in FY06 and 07 has increased but variability around the expected cost of energy has decreased 	M	H		H		
2. Commodity -Trade		M	H				
3. Exchange Rate	→ Slightly decreased exposure and EaR	H	M				
4. Interest Rate	→ Slightly increased variable rate debt and EaR	H	M				
5. Credit	<ul style="list-style-type: none"> ↑ Risk has increased for the higher cost operators 	H	L				
6. Pension Fund	↓ Improved fund performance	M	H				
7. Dam Safety	→ Interim risk mitigation measures on Campbell River system are complete. Assessments of options for permanent measures are continuing	L	E	E	H	H	
8. Generation Asset	→ Ageing equipment, outages and failures	M	H	H	H	M	
9. Customer Reliability	→ F06 Q3 quarterly ASAI and CAIDI are better than targets based on the 5-year (F2001-05) average due to the absence of major events.	M	M	H		H	
10. Reliability of Supply	↑ Winter capacity planning underway; additional firm resources required	M	H				
11. Human Resources	<ul style="list-style-type: none"> ↑ Collective agreements with both unions expire on March 31, 2006 ↑ High level of unfilled vacancies and safety performance 	M	M	H		M H	
12. Environment	<ul style="list-style-type: none"> ↑ Greenhouse Gas regulation (Kyoto implementation) → IEP / future supply portfolio choices 	M	M		H		
13. Regulatory		M	H		H	H M	

Legend: L = Low, M = Medium, H =High, E = Extreme, ↑ = Driver contributed to an increase in risk, ↓ Driver contributed to a decrease in risk

BC Hydro Risk Dashboard

As Assessed at End of Q4 FY2006

Risk	Drivers	Prob-ability	Consequence				
			Financial	Safety	Environment	Reliability	People
	<div style="border: 1px solid black; width: 20px; height: 10px; display: inline-block;"></div> Significant changes from last quarter <div style="border: 1px solid black; width: 20px; height: 10px; display: inline-block; margin-left: 20px;"></div> Other risks						
1. Commodity - Domestic	↓ Projected cost of energy decreased quite significantly Q over Q → System inflow forecast for FY07 continues to be significantly below normal → BC Hydro will continue to be a net electricity importer (10,000GWh in the next 3 years). Significant portion of these purchases are subject to market price fluctuations. Permanent price increases coupled with low inflows might result in further increases in energy costs.	M	H		H		
2. Human Resources	↑↓ Continued poor safety performance (Bamfield, Feb 2006). COPE and IBEW Memorandums of Settlement have both been ratified	M	M	H		M	H
3. Regulatory		M	H		H	H	M
4. Credit	↑ Risk continues to be high for the higher cost operators	H	L				
5. Commodity -Trade		M	H				
6. Exchange Rate	→	H	M				
7. Interest Rate	↑ Net Debt remains within statutory borrowing limit of \$8.8 billion, yet forecasted to breach limit in July 2008 given significant increase in spending and no rate increase.	H	M				
8. Pension Fund	↓ The funded ratio increased to 99.5% in March 31, 2006 from 97.0% in December 31, 2005 due primarily to investment performance.	M	H				
9. Dam Safety	→ Q4 saw no major changes in the risk index of our facilities.	L	E	E	H	H	
10. Generation Asset	→ Yet to be updated! Ageing equipment, outages and failures	M	H	H	H	M	
11. Customer Reliability	↑ F2006 Q4 reliability is worse than target (> half a million customer interruptions and 2 million lost hours).	M	M	H		H	
12. Reliability of Supply	↑ System deficit to meet peak demand at 90% confidence level increases by approximately 150MW per year.	M	H				
13. Environment	→ Greenhouse Gas regulation (Kyoto implementation) → IEP / future supply portfolio choices	M	M		H		
14. First Nations		M	H			H	

Legend: L = Low, M = Medium, H =High, E = Extreme, ↑ = Driver contributed to an increase in risk, ↓ Driver contributed to a decrease in risk

BC Hydro Risk Dashboard

As Assessed at End of Q1 FY2007

Short-Term Priority*	Risk	Drivers	Prob-ability	Consequence				
				Financial	Safety	ENVIR-onment	Reliability	People
SAFETY	1.Safety	<ul style="list-style-type: none"> ↓ Q1 F2007 AIF performance of 1.4 is well on track to meet the annual target of 2.3 ↑ There were 4 level 1 incidents reported this quarter – three involving the public and one near miss involving an employee → There were 66 near misses reported in Q1 compared to 69 in Q4 last year 	M		H			M
	2. Dam Safety	<ul style="list-style-type: none"> → Q1 saw no major changes in the risk index of our facilities. → Spillway Gate reliability assessments were completed at 5 high-risk sites this year and found that gate reliability was inadequate. 	L	E	E	H	H	
RELIABILITY	3. Supply	→ System deficit to meet peak demand at 90% confidence level increases by approximately 100MW per year.	M				H	
	4. First Nations		M	H			H	
	5. Generation Asset	→ Multi-year capital program continues to address highest risk asset health concerns	M	H	H	H	M	
	6. Regulatory-Domestic		M			M	H	
	7. Customer Reliability	→ Reliability performance is generally in line with quarterly year-to-date targets although CAIDI is worse than target.	M	M	M		H	
PEOPLE	8. Human Resources	<ul style="list-style-type: none"> ↓ ABSU and COPE Local 378 ratified a new 4-year collective agreement. The settlement eliminates the potential for a legal labour dispute at ABSU that could have significantly impacted BC Hydro's ability to provide normal levels of service. → High levels of vacancies across BC Hydro 	M		M		M	H
ENVIRONMENT	9. Environment	<ul style="list-style-type: none"> ↓ Reduction in risk associated with water use plan ↑ Green House regulation and long-term energy supply choices increase environmental risk. ↑ Ministry of Environment presented BCH with a unilateral change order to its Rock Bay Remedial AIP which will likely complicate negotiations with adjacent site owners 	M	M	L	H		

Legend: L = Low, M = Medium, H =High, E = Extreme, ↑ (↓) = Driver contributed to an increase (decrease) in risk from the previous quarter

*Achievement of these short-term priorities may be impacted by one or more of the following key risks. Key risk(s) are aligned to the Short-term priority that is most likely to be impacted. Customer satisfaction priority is directly or indirectly affected to some extent by all of the key risks to BCH's Short-term priorities. Page 1

BC Hydro Risk Dashboard

As Assessed at End of Q1 FY2007

Short-Term Priority*	Risk	Drivers	Probability		Consequence				
			F2007	3-5 years	Financial	Safety	Environ-ment	Reliability	People
FINANCIAL	10. Commodity - Domestic	<ul style="list-style-type: none"> ↓ Projected cost of energy decreased quite significantly Q over Q → System inflow forecast for FY07 continues to be significantly below normal → BC Hydro will continue to be a net electricity importer (13,000GWh next 3 years). Significant portion of these purchases are subject to market price fluctuations. 	L	H	H				
	11. Credit	<ul style="list-style-type: none"> ↑ Domestic: Risk continues to be high for the higher cost operators 	L	L	M				
	12. Commodity - Trade		L	M	H				
	13. Exchange Rate	<ul style="list-style-type: none"> ↑ The quarterly change in 1-year exposure from Q4 FY06 to Q1 FY07 was net positive US\$137 million and overall FX Exposure as of June 30, 2006 was long \$95 million, within Policy limits. 	L	L	M				
	14. Interest Rate	<ul style="list-style-type: none"> → Net Debt remains within statutory borrowing limit of \$8.8 Billion, yet forecasted to breach limit in June 2009 given significant increase in spending. 	L	M	M				
	15. Pension Fund	<ul style="list-style-type: none"> ↑ The estimated funded ratio of 97.8% at June 30, 2006 is down from the March value of 99.5%. 	L	M	M				
	16. Powerex Regulatory		L	M	H				
17. RRA Regulatory		H	N/A	H					

Legend: L = Low, M = Medium, H = High, E = Extreme, ↑ (↓) = Driver contributed to an increase (decrease) in risk from the previous quarter

*Achievement of these short-term priorities may be impacted by one or more of the following key risks. Key risk(s) are aligned to the Short-term priority that is most likely to be impacted. Customer satisfaction priority is directly or indirectly affected to some extent by all of the key risks to BCH's Short-term priorities.

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7.0 Reference: Exhibit B-15, Attachment 5, Annual Audit Plan, pages 7 to 9

3.7.2 The table in Section 4, page 8, states that audits were performed in F2006 that included components of regulations such a NERC, FERC, etc. Please provide copies of these audits.

RESPONSE:

The IT Security audit report, provided in the attachment to BCUC IR 1.13.0, assessed compliance with some NERC requirements. FERC regulations were included in one Powerex audit. Please see the response to BCUC IR 1.13.0 for an explanation regarding the Powerex audit reports.

Independent Power Producers of B.C. Information Request No. 3.7.3 Dated: September 8, 2006 British Columbia Hydro & Power Authority Response issued September 29, 2006	Page 1
British Columbia Hydro & Power Authority BC Hydro F07/F08 Revenue Requirements Application - Evidentiary Update	Exhibit: B-18

7.0 Reference: Exhibit B-15, Attachment 5, Annual Audit Plan, pages 7 to 9

3.7.3 The table in Section 4, page 8, states that an audit was performed in F2006 on the contract management of IPPs. Please provide that audit report and the management responses to it.

RESPONSE:

The Distribution integrated audit report, which included IPP contract management, was issued in the first quarter of F2007. The final report, which includes management's response, is attached.



INTERNAL AUDIT REPORT

DISTRIBUTION AUDIT Q4 F2006

IPP CONTRACT MANAGEMENT PROCESS

CUSTOMER SATISFACTION INDEX PERFORMANCE MEASURE

CORPORATE POLICY COMPLIANCE

AUGUST 1, 2006

AU0702DIST

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Distribution Line of Business F2006

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AUDIT	TYPE	RATING
<p>1. IPP CONTRACT MANAGEMENT PROCESS</p> <p>1a Executive Summary 1b Background 1c Audit Objective and Scope 1d Governance Framework 1e Project Oversight and Contract Management 1f Monitoring & Reporting 1g Audit Recommendations and Management Responses</p>	<p>RISK BASED</p>	<p>G</p>
<p>2. CUSTOMER SATISFACTION INDEX PERFORMANCE MEASURE</p> <p>2a Executive Summary 2b Background 2c Audit Objective and Scope 2d Relevance 2e Reliability</p>	<p>CYCLICAL</p>	<p>G</p>
<p>3. CORPORATE POLICY COMPLIANCE</p> <p>3a Overview 3b Compliance with Financial and Management Controls 3c Compliance with Business and Travel Expense Policies</p>	<p>FINANCIAL MANAGEMENT CONTROLS</p> <p>BUSINESS AND TRAVEL EXPENSE POLICIES</p>	<p>Y</p> <p>Y</p>

Legend:



1. IPP Contract Management Process

1a Executive Summary

Audit Objective

- Review the Independent Power Producer (IPP) Contract Management process subsequent to the award of the Energy Purchase Agreements (EPAs) and assess whether controls are effective and the process is clear, complete and efficient.

Key Findings

- The fieldwork for this audit was completed in May 2006, prior to the implementation of the corporate reorganization.
- Overall, the IPP Contract Management process is well-defined. Contract Management staff are knowledgeable and capable, IPPs are delivering supply and complying with major provisions of the EPAs, and BC Hydro payments to IPPs are in accordance with the EPAs. However, there are opportunities to enhance controls and efficiency.
 - ◆ Roles and responsibilities are not always clearly communicated or consistently understood by other groups within BC Hydro that are involved in the IPP Contract Management process. This increases the risk of potential oversight, gaps or overlaps between interdependent groups such as Contract Management, Distribution Finance and Generation Line of Business.
 - ◆ Contract Managers are responsible for protecting BC Hydro's interests by ensuring IPPs comply with EPA terms and conditions, while at the same time assisting IPPs to achieve Commercial Operation. An oversight function or escalation framework for these potentially conflicting responsibilities is not clearly defined.
 - ◆ Senior management roles in the Contract Management process are not clearly defined. Some IPPs have directly approached BC Hydro executive and senior management for resolution of issues. There are no specific examples of senior management addressing IPP requests directly. However, perception of any preferential treatment would pose a reputation risk to BC Hydro.
 - ◆ There are no formal policies to address review and approval of EPA amendments and the related tolerance and approval structure for operational decisions made by Contract Managers.
 - ◆ Documentation and filing standards vary among Contract Managers, increasing the risk that supporting evidence may not be available in an EPA file, and also making it difficult for another individual to take over an existing file.
 - ◆ Reporting to senior management is not standardized or consistent and is on an exception basis. Without formal reporting, it is unclear how key decision makers are able to make timely and appropriate decisions.
- We noted exceptions during the audit, which, although not necessarily material, do provide examples of potential consequences of the above issues. As outlined in the Integrated Electricity Plan, BC Hydro plans to increase purchases from IPPs to assist in meeting growing domestic electricity demands. As this strategy is rolled out, enhanced controls and efficiency over the resulting agreements will become increasingly important.

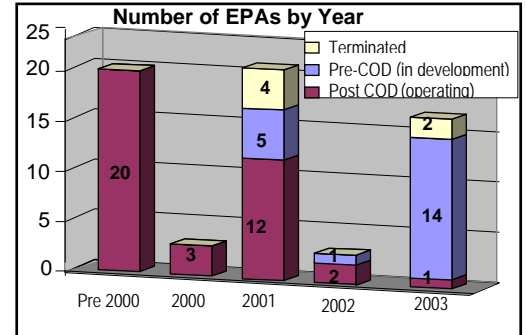
Recommendations and Management Action Plans

- Management agrees with the recommendations in the audit report and has targeted completion of all action plans by December 31, 2006.

1. IPP Contract Management Process

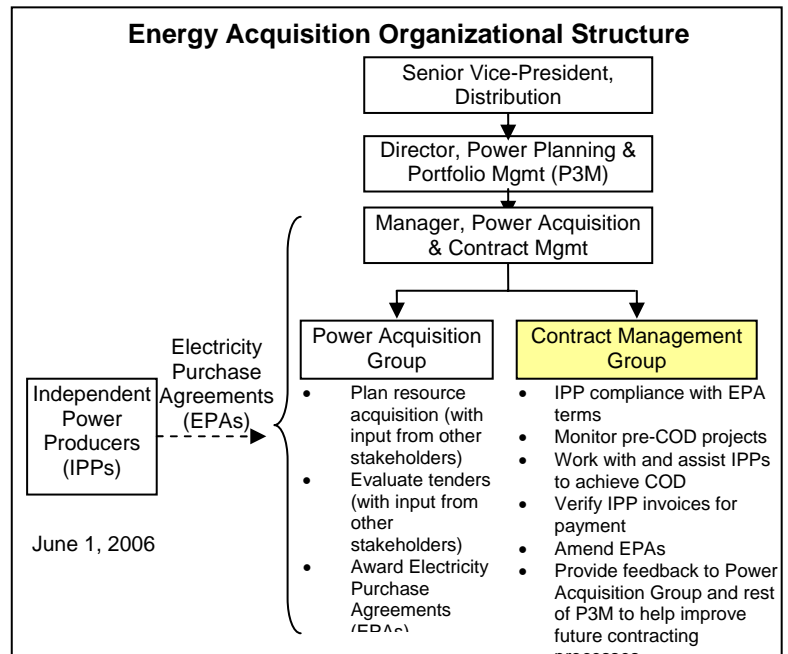
1b Background

- Since the 1980s, BC Hydro has issued several Calls for Power, resulting in 64 Electricity Purchase Agreements (EPAs) with Independent Power Producers (IPPs). Six of these agreements have since been terminated as they were deemed not to be economically viable, or public opposition caused the IPP to abandon the project.
- The remaining 58 EPAs are projected to contribute approximately 8,800 GWh per year and 2,400 MW of capacity to BC Hydro's system once they reach Commercial Operation Date (COD). 38 projects have already reached COD. The remaining 20 projects are currently under development.

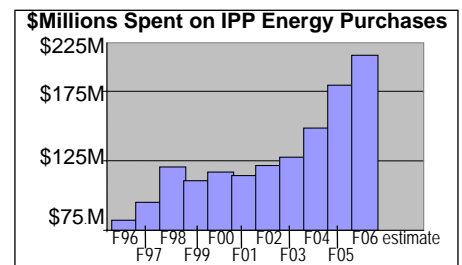


- The chart to the right summarizes BC Hydro's organizational structure related to energy acquisition. Two key groups deal with EPAs:

- The Power Acquisition group is responsible for planning resource acquisition, evaluating tenders and awarding EPAs. At the time of the audit, this group was in midst of the F2006 call for power.
- The Contract Management (CM) group, with five staff dedicated to managing EPAs, is responsible for building and maintaining business relationships, administering and managing long-term agreements, and ensuring compliance with contractual and regulatory requirements once the EPA has been awarded. This group is BC Hydro's primary point of contact with IPPs, and is the focus of this audit.



- BC Hydro's electricity purchase costs from IPPs are now in excess of \$500M per year. The CM group is responsible for and manages all IPP contracts. However, three large complex contracts (Alcan, Arrow Lakes Hydro and Island Co-Generation) are managed jointly with Generation Operation as they require more day-to-day scheduling and coordination. IPP contracts managed solely by the CM group have a total value exceeding \$200M per year.



- An audit of the IPP Contract Management process in F2003 found that staff did not clearly understand the governance structure, roles, and approval routing as these were not clearly defined and communicated. At the time, IPP Contract Management was performed in various departments and lines of business, depending on the call and nature of the energy supply.

1. IPP Contract Management Process

1c Audit Objective and Scope

Objective

- ❑ Review the IPP contract management process and assess whether the controls are effective and the process is clear, complete and efficient.

Scope

- ❑ The scope included a review of the key business risks, business processes and procedures, and controls over the IPP Contract Management process, which comprised of the following key components:
 - ◆ Governance Framework;
 - ◆ Project Oversight during pre-Commercial Operation Date (COD) phase;
 - ◆ Administration and Management of post-COD Contracts; and
 - ◆ Monitoring and Reporting.
- ❑ The audit excluded a review of the IPP agreements in Non-Integrated Areas as these are administered by another group within Distribution and not by the Contract Management group in Power Planning and Portfolio Management. The audit also excluded a review of the IPP contract tendering and award process as this activity was going through changes and was in the midst of a call for power at the time of the audit.
- ❑ The audit approach included review of reports, agreements, and other key documents, discussions with staff and management, and testing of payments made to the IPPs.

1. IPP Contract Management Process

1d Governance Framework

Mandate and Purpose

- ❑ BC Hydro's resource acquisition strategy includes using Independent Power Producers (IPPs) to assist in meeting the growing domestic electricity demands and is consistent with the BC Government's Energy Plan and BC Hydro's long-term Integrated Electricity Plan (IEP).
- ❑ BC Hydro's purpose and long term goals as they relate to IPPs are clearly understood by Contract Management staff. Their function is consistent with corporate long-term goals and helps BC Hydro deliver reliable power, at low cost, for generations.

Management Direction

- ❑ Management direction is clearly communicated to and accepted by all levels of responsibilities. Contract Management staff understand what they are meant to be doing and how the IPP Contract Management functions contribute to the overall BC Hydro objectives.

Roles and Responsibilities

- ❑ Roles and responsibilities as they relate to IPPs are defined and generally understood by Contract Management staff. A list of activities performed by Contract Management is also available on the Distribution website. However, we noted that:
 - ◆ Roles and responsibilities relating to other groups within BC Hydro that are involved in the IPP Contract Management process are not always clearly communicated to those outside of the Contract Management department. Furthermore, although roles and responsibilities are documented, they are not regularly reviewed and updated. This increases the risk of potential oversights, gaps or overlaps between interdependent groups such as Contract Management, Distribution Finance, and Generation Line of Business.
 - ◆ Contract Managers are responsible for: (1) Ensuring IPPs comply with the EPAs and protecting BC Hydro's interests; (2) Ensuring fair and consistent treatment between the various IPPs, and (3) Assisting IPPs achieve Commercial Operation Date (COD). It is not clearly defined which of these responsibilities should take priority in case of any conflicts between BC Hydro's interests and those of the IPP.
 - ◆ Roles relevant to senior management are not clearly defined. Staff indicated that on occasion, certain IPPs have directly approached BC Hydro executive and senior management for resolution of issues. There are no specific examples of senior management addressing IPP requests directly. However, perception of any preferential treatment would pose a reputation risk to BC Hydro.

Policies and Procedures

- ❑ Most contract management processes are documented. However the documentation is informal, and focuses more on procedures rather than defining policies.

1. IPP Contract Management Process

- ◆ There are no formal policies around the approval of changes/amendments to the EPAs. Approval structure for changes to operational requirements is not clearly defined.
- ◆ Contract Managers agreed that significant variances should be escalated to senior management for approval. However, there is no standard definition of significant. Therefore, there is no assurance that the appropriate level of management is reviewing and approving changes to EPAs.
- ◆ There is currently a draft Power Planning and Portfolio Management Policy Paper to address situations where EPAs can be amended. However, it does not state the approval structure. Unapproved changes to the EPA could result in BC Hydro being exposed to a level of risk that is unacceptable to senior management.
- ◆ Some EPAs require judgement on the part of the Contract Managers, but there are no policies in place outlining thresholds for consultation or approval of decisions.
 - For example, EPAs issued in 2003 require “reasonable and prudent” insurance amounts, similar to what lenders would “normally” require. We noted one case where the Contract Manager accepted insurance of \$5M, yet according to F2006 criteria, a plant of similar size would require \$20M of insurance.
 - There are additional 2003 EPAs where the IPP is now approaching the construction phase, and will therefore need to obtain appropriate insurance coverage. There is currently no process or policy in place to review or approve decisions made by the Contract Managers regarding the adequacy of the IPP’s insurance coverage.

Capability and Resources

- CM staff demonstrated the necessary knowledge, abilities and commitment to fulfil their responsibilities and staff resources appear adequate for the current level of work.

1e Project Oversight and Contract Management

Progress of Pre-Commercial Operation Date (COD) Projects

- During the pre-COD phase, the Contract Management group is responsible for monitoring progress and compliance, assisting the IPP where required, assessing the probability of achieving COD, and revising the estimated operation date based on developments during the project.
- All twenty projects currently in development (1,700 Gwh) are behind schedule, with an average expected delay of nineteen months. Seven projects (35%) have expected delays of two years or greater. Another seven projects have expected delays of one to two years.
- Most of the projects have a low probability of achieving COD. Contract management staff has assessed thirteen projects (65%) to have a probability of 50% or less of achieving COD. Only two projects (10%) are considered ‘very likely’ to achieve COD.

1. IPP Contract Management Process

- ◆ Based on our discussions and review of documents, we believe that these delays and risks of attrition are beyond the control of the Contract Managers. Contracting practices in the past, such as awarding EPAs to proponents in the early stages of project development, have contributed to a low probability of current projects achieving COD and significant delays in projected completion dates.
- ◆ Furthermore, in many cases, there are factors that the IPPs cannot (or can no longer) control, including opposition by local interest and First Nations groups, and the unanticipated growth in the economy that has increased costs and created resource shortages.
- Contract Managers provide revised estimates and schedules to the Market Forecast group on a quarterly basis for forecasting supply and demand of electricity. However, there are no predetermined criteria to assess and substantiate the likelihood of achieving COD. As each Contract Manager uses his/her own judgement, there is no consistent approach to evaluating the likelihood of success. This evaluation could affect the accuracy of the market forecasts and related decisions.
- Staff informed us that in the event of a shortfall in delivered electricity from the IPPs, BC Hydro will rely on a blend of short-term market purchases as well as accelerating, and adjusting the volumes in future calls. Short-term market purchases are managed by Generation.
- Staff also informed us that for the F2006 Call for Power, attrition risk is being managed by setting higher standards when evaluating proposals and strengthening the EPA performance terms, such as imposing consequences for COD delays and delivery shortfall.

IPP Performance and Compliance

- IPPs are generally delivering supply as agreed and complying with the EPAs. However, we noted the following exceptions:
 - ◆ IPPs are not always supplying the appropriate or correct documentation, or are submitting them late. These include current proof of insurance, annual operating plans, quarterly reports, and notification of planned outages. Contract Managers have expressed concerns with this, but state there is very little they can do. Aside from completely terminating the entire EPA, there are no penalties built into the existing EPAs to enforce these terms and conditions.
 - ◆ Liquidated damages are defined in some EPAs as penalties for supply shortfalls; however, this area is not adequately monitored. We noted one instance where liquidated damages were not applied because the unplanned outages were not reported to BC Hydro. Although the amounts were minimal, it is not clear from the file review whether it was waived for commercial reasons or an administrative error. There was no documentation in place to confirm that it was a management decision to waive the penalty.
 - ◆ There is no formal and consistent approach to process, verify and approve documents when IPPs achieve COD. As a result, IPPs may be granted COD status without meeting operational and documentation requirements, exposing BC Hydro to potential system and environmental risks as well as the perception of inequitable treatment of IPPs. We reviewed 10 projects and noted 4 instances where evidence to support the achievement of COD was not available. For

1. IPP Contract Management Process

example, CEMP (Construction Environmental Management Plans) certificates are required for COD to be granted.

Controls over Payments

- Payments to IPPs are generally in accordance with the EPAs. However, we noted the following exceptions:
 - ◆ Although one EPA clearly states that the IPP “shall limit peak capacity” to the contracted amount, another section of the EPA states that BC Hydro will pay for all capacity taken. There had been correspondence with the IPP regarding the capacity supplied and the effective rates, but we were unable to find details of the negotiated outcome. In 2004 the Contract Manager, who is no longer with BC Hydro, documented in the file that a lower tariff for the excess capacity had been discussed with the IPP during negotiation. Though the lower tariff was not in the final executed EPA, there was no documentation in the file reflecting the management review and approval of the final decision.
 - ◆ In another instance, Contract Management staff discovered an error in invoicing (prepared by BC Hydro on behalf of the IPP) in which incorrect tariffs were applied for a period of four months. Once the error was discovered, a resolution in compliance with the EPA terms was not determined for another four months. The resolution was to deduct the overcharged amount over the following five months’ invoices. We found no evidence of management review and approval for this resolution.
 - ◆ Some older contracts (e.g. 2001 EPAs) provide an implicit definition of the tariff, but do not explicitly state how the tariffs are to be calculated. The contract design leaves the calculation method open for interpretation, and the subsequently agreed upon calculations are not clearly supported by signed agreements or amendments. Authority levels are not defined within Contract Management for approving assumptions made regarding calculation methods.
 - For example, we noted one instance where the definition of annual tariff increase could be subject to interpretation by different parties. Although the actual calculation appeared reasonable, the ambiguity of the definition could expose BC Hydro to additional costs if the IPP interpreted the definition differently and BC Hydro was unable to support its methodology.
- IPP contracts are not set up as purchase orders or contract orders within BC Hydro’s purchasing system. As a result, tracking and monitoring of cumulative payments made to individual IPPs becomes more cumbersome and requires manual intervention.
- Tariff calculations and invoice reconciliations are performed on large, complex spreadsheets which are not independently reviewed for accuracy. Although it is common business practice to perform such functions using spreadsheets, there is an inherent risk of undetected calculation errors when using complex spreadsheets. This risk is compounded by the fact that the spreadsheets have been developed over a number of years and are passed on from person to person.
 - Tariff calculations are very complex in some EPAs, and change with market price fluctuations. Individual Contract Managers have developed and are using their own

1. IPP Contract Management Process

- complex spreadsheets to calculate these tariffs without an independent review by their peers to confirm accuracy of the calculations when the tariff rates change.
- Invoice reconciliation performed by Distribution Finance is done using a large spreadsheet developed over the years. The current spreadsheet contains information not needed to reconcile the invoice, and could be streamlined.

File Management

- A new database system (Contraxx) was introduced in February 2006 to track all information associated with the EPA, including notes, comments and decisions. It also allows Contract Managers to attach contract documents, reports and correspondence so that everything may be kept in a central repository and be accessible online by any Contract Manager.
 - ◆ Since implementation of Contraxx some newer documents have been attached to the database. However, historical information has not yet been imported due to the time and resources required. CM has a desire to fully populate Contraxx, but at this stage a plan has not yet been developed due to resource limitations.
 - ◆ We believe that Contraxx is a useful tool, but will not be used to its full potential unless it is fully populated with key information, including notes, correspondence and long-term agreements. These items are currently available either in paper files only or are on the network drive but not always cross referenced to the relevant projects.
- In general, file documentation has greatly improved since our audit in 2003. However, we noted areas where controls can be further strengthened.
 - ◆ File documentation is located in numerous locations, including hard copy, Contraxx database, network drive and email. Each Contract Manager files documents in his/her own preferred methodology, making it difficult for someone new to take over the contract.
 - ◆ All EPAs have a primary Contract Manager as well as an alternate. We noted one case where work was performed by a primary Contract Manager but was not documented. The Contract Manger is now on leave and the alternate is not aware of what was discussed and agreed upon with the IPP.
 - ◆ File folders contain important documents, sometimes original agreements, and confidential information regarding IPPs and EPAs. These folders are kept in open cabinets located in an open area. Storage in this manner can lead to documents being lost, damaged or viewed by unauthorized personnel.
 - ◆ We noted instances where action items were not fully completed or where the resolution was not adequately documented. Furthermore, we found action items that were noted in the paper file or in the Contraxx Notes section, but were not set up as *actions* in the Contraxx database. Consequently, these issues are not picked up in the weekly outstanding action item report. This increases the risk of action items either being delayed or not completed.

1. IPP Contract Management Process

1f Monitoring & Reporting

- There are no formal reports issued to senior management. Reporting to senior management is mainly verbal or through email on an ad-hoc and need-to-know basis. Contract Managers informed us that significant issues are escalated to the Manager, Power Acquisition and Contract Management. Depending on the nature and significance, this may be further elevated to the Director, Power Planning and Portfolio Management and the Senior Vice-President, Distribution. However, this is on a case-by-case basis, and there is no standard definition of *significant*. Contact managers would consult with the alternate contract manager and/or the Team Leader to help ensure consistency.
- ◆ There are no performance measures in place for monitoring and evaluating the effectiveness of IPP Contract Management. Therefore, it is difficult for management to assess the effectiveness and strengths and weaknesses of the function, what they are doing right and where improvements could be made.
- ◆ Without formal reporting, it is unclear how senior management and other key decision makers are able to make timely and appropriate decisions.

1. IPP Contract Management Process

1g Audit Recommendations and Management Responses

	Recommendations	Management Action Plans
Governance Framework		
1.	<p><input type="checkbox"/> Contract Management should formalize, and document roles and responsibilities, including the prioritization of contract management roles, and communicate to all groups and individuals who may be involved in the IPP process, including other departments, and senior management.</p>	<p><input type="checkbox"/> Management agrees. Contract Management will document and formalize roles and responsibilities including prioritization and allocation of responsibilities and will communicate to relevant groups in BC Hydro. Expected completion by December 31, 2006.</p>
2.	<p><input type="checkbox"/> Contract Management should formalize, document and communicate policies and procedures, to all groups and individuals who may be involved in the IPP process.</p>	<p><input type="checkbox"/> Management agrees. Contract Management will document and formalize policies and procedures and communicate to those involved in the IPP process. Expected completion by December 31, 2006.</p>
3.	<p><input type="checkbox"/> For EPAs that do not provide specific insurance requirements, Contract Managers should consult with the Insurance Manager in Treasury to ensure adequate coverage is obtained.</p>	<p><input type="checkbox"/> Management agrees. For EPAs that do not provide specific insurance requirements, Contract Management will consult with the Insurance Manager in Treasury to ensure adequate coverage is obtained. This will be implemented immediately.</p>
Project Oversight and Contract Management		
4.	<p><input type="checkbox"/> Contract Management should establish predetermined criteria to assess and substantiate the likelihood of achieving COD so that there is a consistent approach to evaluating the likelihood of success and improve the accuracy of the market forecasts and related decisions.</p>	<p><input type="checkbox"/> Management agrees. Contract Management will investigate whether and/or how CM can establish predetermined criteria to assess and substantiate the likelihood of achieving COD in a consistent manner. If suitable criteria can be determined, a relevant process will be designed and implemented. Expected completion by December 31, 2006.</p>
5.	<p><input type="checkbox"/> Contract Management should report to senior management the reasoning for waiving liquidated damages for commercial reasons. If material, senior management should approve prior to advising the IPPs.</p>	<p><input type="checkbox"/> Management agrees. Contract Management will document and report to senior management material variances to EPA terms and conditions. This will be implemented immediately.</p>
6.	<p><input type="checkbox"/> Contract Management should develop and implement a formal and consistent approach to process, verify, monitor and</p>	<p><input type="checkbox"/> Management agrees. Contract Management will develop and implement a formal and consistent approach to process,</p>

1. IPP Contract Management Process

	Recommendations	Management Action Plans
	approve terms and conditions before granting COD to IPPs. A checklist developed to monitor the completeness of required documents at the commencement of the EPA would be useful for review by the CM Manager.	verify, monitor and approve terms and conditions before granting COD to IPPs. Expected completion by December 31, 2006.
7.	<input type="checkbox"/> Contract Management should institute a process for independently reviewing the accuracy of tariff change calculations and invoice reconciliations performed on large, complex spreadsheets.	<input type="checkbox"/> Management agrees. Contract Management will conduct independent peer review when tariff changes each year. This will be implemented immediately.
8.	<input type="checkbox"/> Contract Management should ensure sensitive and important documents, such as original agreements, and confidential information regarding IPPs and EPAs are stored in locked cabinets to minimize the risk of these documents being lost, damaged or viewed by unauthorized personnel.	<input type="checkbox"/> Management agrees. Contract Management will ensure sensitive and important documents are securely stored to minimize the risk of these documents being lost, damaged or viewed by unauthorized personnel. Expected completion by December 31, 2006.
9.	<input type="checkbox"/> Contract Management should plan to fully utilize the Contraxx database system by populating it with key information relating to existing EPAs so that all information can be maintained in one area.	<input type="checkbox"/> Management agrees. Contract Management plans to fully utilize the Contraxx database system. The database will be populated with key information relating to existing EPAs once available resources are obtained. Expected completion by December 31, 2006.
Monitoring & Reporting		
10.	<input type="checkbox"/> Distribution management should define formal reporting requirements and request periodic reporting of IPP contract management information so that BC Hydro can better anticipate and plan power supply and demands.	<input type="checkbox"/> Management agrees. Contract Management will consult with senior management to determine what appropriate and relevant reports can be provided on a periodic basis. Contract Management will provide reports as requested by senior management. Expected completion by December 31, 2006.
11.	<input type="checkbox"/> Contract Management should develop and implement key performance indicators to periodically report on the efficiency and effectiveness of the IPP contract management process.	<input type="checkbox"/> Management agrees. Contract Management will investigate the appropriate measures that meaningfully track the performance of the Contract Management group. Appropriate measures, once identified, will be implemented and tracked. Expected completion by December 31, 2006.

2. Customer Satisfaction Index Performance Measure

2a Executive Summary

Audit Objective

- ❑ To provide assurance that the Customer Satisfaction Index reported by BC Hydro is a relevant and reliable measure for indicating overall customer satisfaction with BC Hydro.

Definition

- ❑ The Customer Satisfaction Index is a blended representation of surveys of all BC Hydro customer segments. It is an indicator of both residential and business perception of the overall BC Hydro entity.

Key Findings

- ❑ The Customer Satisfaction Index is a relevant performance measure. The measure is timely, and is reported twice per year, which is above the industry standard of once per year. The measure is useful and effective in gauging how BC Hydro is perceived by its customers as well as providing feedback on how certain programs and initiatives are being received by customers.
- ❑ The Customer Satisfaction Index is a reliable performance measure. However, it has undergone changes from year to year relating to the mix and weighting of individual customer categories, making it difficult to compare across periods without additional analysis.
- ❑ The results of this Index are considered when making decisions, but with Customer Satisfaction historically being at a high level and consistently above target, there has been little need for actions to respond to the Index results.
- ❑ Although BC Hydro's methodology appears reasonable, the Customer Satisfaction Index is not directly comparable to external benchmarks.
 - ◆ The external benchmark used by BC Hydro is composed solely of residential customers, whereas BC Hydro's Customer Satisfaction Index is a blend of residential, key account, other business and call centre customers.
 - ◆ While Customer Satisfaction is a common industry measure, other utilities typically do not disclose their methodologies, making it difficult to determine industry standards.

Recommendations and Management Action Plans

- ❑ Management agrees with the recommendations in the audit report and has targeted completion of all action plans by October 31, 2006.

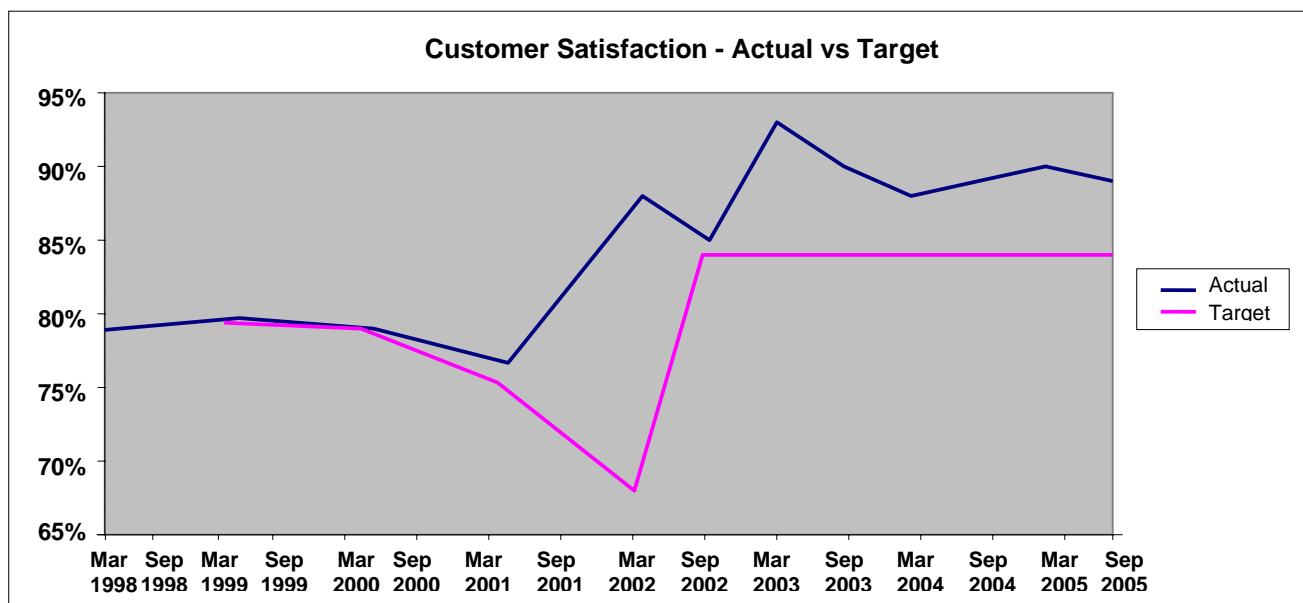
2. Customer Satisfaction Index Performance Measure

2b Background

- ❑ The Customer Satisfaction Index is reported as part of the BC Hydro Annual Report and is included in the BC Hydro Service Plan.
- ❑ The Customer Satisfaction Index requires customers to rate BC Hydro on a scale of 1-10, with 10 being the highest performance. “Satisfied” requires the participant to rate BC Hydro 7 or better. The Index is a blended measure, weighted as follows:
 - ◆ 30% relates to customer surveys sampled from all customer categories, weighted by the revenue associated with each category.
 - ◆ 70% relates to surveys of customers who have had call centre interactions. This sample is allocated equally between key accounts, other business and residential customers.

Customer Satisfaction (%) = 30% x Customer Survey + 70% x Call Centre Survey

- ❑ The performance measure was introduced in 1997 and was directed at Top 1000 business customers, small/medium business customers and residential customers. The measure was calculated quarterly, based on a 10 point scale. Over the next few years, this measure changed to a 5 point scale and back to a 10 point scale, moved from quarterly to semi-annual reporting, and added and removed a transactional (call centre survey) component.
 - ◆ The most recent iteration effective March 2006, defines “very satisfied” as scores of 8-10, and includes residential, key account and other business customers. Results are based on equally weighted scores for each customer segment from a random survey.
 - ◆ Although there is no longer a separate call centre survey component, those customers who have had call centre interactions are already included in the population from which the survey sample is chosen.
 - ◆ For internal reporting purposes such as calculation of eligibility under performance pay, the revised measure has been in place since April 2005.



2. Customer Satisfaction Index Performance Measure

2c Audit Objective and Scope




Objective

- ❑ To provide assurance that the Customer Satisfaction Index reported by BC Hydro is a relevant and reliable measure for indicating overall customer satisfaction with BC Hydro.


Scope

- ❑ We tested the relevance and reliability of the Customer Satisfaction Index by:
 - ◆ Reviewing the supporting documentation for the various components of the measure;
 - ◆ Testing the computation of the metric; and
 - ◆ Conducting interviews of key personnel.
- ❑ Equal importance is placed on relevance and reliability, as one without the other is not a credible representation of performance.
- ❑ The scope of this audit does not extend to detailed audits of the methods and process used by the third-party survey provider.
- ❑ Based on audit procedures, we calculated overall audit ratings as follows:

Description of Rating

	Reasonable assurance has been obtained to satisfy the audit criteria.
	Areas of significant improvement identified.
	Material non-conformities identified.

2d Relevance

Overall Relevance Rating: 

Audit Criteria	Findings
Consistency with strategic direction and goals	<ul style="list-style-type: none"> ○ The metric is aligned with BC Hydro’s Customer Long-term Goals for Customer Satisfaction – “To lead other companies in offering extraordinary value and service”. Its purpose is to indicate customers’ overall satisfaction with BC Hydro.
Timeliness	<ul style="list-style-type: none"> ◆ The metric is calculated twice per year and reported in the Annual Report and the 2nd Quarter Report. Increasing the number of surveys could increase the relevance of the metric, but given the minimal fluctuation in survey results, the additional costs may outweigh potential benefits.

2. Customer Satisfaction Index Performance Measure

Audit Criteria	Findings
Usefulness / Effectiveness	<ul style="list-style-type: none"> ❑ Based on discussions with management, the Customer Satisfaction Index is useful in determining overall customer satisfaction with BC Hydro. <ul style="list-style-type: none"> ◆ Historically, the measure has been at a significantly high level that little to no action has been needed to be taken to specifically improve customer satisfaction. This is primarily due to the interpretation of ‘satisfied’ being a rating of 7-10. Management has decided to narrow the definition of ‘satisfied’ to 8-10 to provide a better measure of customer satisfaction and to more closely align with the long-term goal of “exceptional customer service”.
Understand-ability	<ul style="list-style-type: none"> ❑ Generally, the Customer Satisfaction Index is understandable. The measure is defined, in general terms, in the BC Hydro Annual and Quarterly reports along with the Service Plan. However, the following characteristics restrict the understandability of the measure: <ul style="list-style-type: none"> ◆ The measure is currently made up of a blending of customer segments (residential, business, key account) and includes call centre surveys. While the index is described as a composite measure, no definition of the breakdown of the measure is provided aside from stating that 30% comes from all customers as a population and 70% being from call centre surveys. The weighting or representation of each customer segment is not specified. ◆ A benchmark comparison is also included to help define how BC Hydro compares to other utilities in Canada. The Customer Satisfaction Index is a blend of all customers of Hydro, business, key account and residential. The benchmark survey is a survey of residential customers only, yet is presented as a one to one comparison to the BC Hydro measure.
External Comparability	<ul style="list-style-type: none"> ❑ Customer Satisfaction Index is externally comparable, but with limitations. <ul style="list-style-type: none"> ◆ Most other Canadian utilities provide a measure of customer satisfaction in their annual reports. The majority of utilities reviewed use a 10-point scale to evaluate customer satisfaction, similar to BC Hydro. However, each company has its own methodology to calculate the metric which is intended to be representative of the overall satisfaction of their customers. ◆ Also, as noted above, the external benchmark available includes residential customers only, rather than all customer segments.

	Recommendations	Management Action Plans
	Relevance	
1.	<ul style="list-style-type: none"> ❑ Whenever the metric is reported, management should ensure it is fully defined, including explanation of the weighting of each customer segment in 	<ul style="list-style-type: none"> ❑ Management agrees. All reporting of the metric will be accompanied by a full explanation of how it is calculated, including the customer weighting method applied.

2. Customer Satisfaction Index Performance Measure

	Recommendations	Management Action Plans
	BC Hydro's calculation.	The next Customer Satisfaction Index measure will be reported for the quarter ending September 30, 2006. Completion expected by October 31, 2006.
2.	<input type="checkbox"/> Management should redefine the benchmark survey in the annual report and service plan to more accurately describe the differences between the benchmark used and BC Hydro's metric.	<input type="checkbox"/> Management agrees. A new benchmark measure of customer satisfaction will be used in F2007 as BC Hydro is participating for the first time in JD Power and Associates' residential customer satisfaction benchmarking survey. Any differences between BC Hydro's own customer satisfaction measures and those used by JD Power will be fully described in any reporting. Completion by October 31, 2006.

2e Reliability

Overall Reliability Rating:



Audit Criteria	Findings
Accuracy	<input type="checkbox"/> The performance metric is calculated using data supplied by a third-party survey company. <input type="checkbox"/> The metric is calculated accurately using the formula established and the proper data inputs. ♦ We noted that the mid-year Customer Satisfaction Index was weighted using the previous year-end revenue amounts. This is due to the amounts not being calculated and segmented in the same manner as the Index at mid-year. The increased accuracy of the measure would not be enough to offset the added cost associated with preparing the updated numbers.
Fairness	<input type="checkbox"/> The performance measure is free from bias and is calculated based on objective information. ♦ Survey data is obtained via a third-party surveyor supplied in summarized, table form used to calculate the index. <input type="checkbox"/> The performance measure is weighted 30% all customers and 70% call centre surveys. Customer Care Management believes there is too much emphasis placed on the call centre survey aspect, and is therefore eliminating the separate call centre survey component from this metric. ♦ Customers who have had call centre interaction will still be included in

2. Customer Satisfaction Index Performance Measure

Audit Criteria	Findings
	the population from which the survey sample is selected, but there will no longer be a separate survey of only those customers with call centre interaction.
Verifiability	<ul style="list-style-type: none"> <li data-bbox="456 436 1505 604">❑ By its nature, survey data is subjective and exists only at a point in time, and therefore, is not reproducible. To mitigate this risk, a third-party surveyor is contracted to perform the survey and remove bias. Survey results are provided by the surveyor and can be used to independently reproduce the Index. <li data-bbox="456 625 1505 764">❑ However, instructions for performing the calculation, (including sources of data, steps to take, etc.), have not been documented. This would make it difficult to reproduce the calculation if the individual normally responsible for this task was unavailable.
Internal Comparability	<ul style="list-style-type: none"> <li data-bbox="456 785 1505 890">❑ Although the calculation behind the metric has changed numerous times over the years, the intent behind the metric has remained constant. Each iteration has been to provide a more accurate reflection of the metric. <ul style="list-style-type: none"> <li data-bbox="505 911 1208 942">◆ The metric has been in its current form since 2003. <li data-bbox="505 963 1505 1092">◆ Beginning in March 2006, for external reporting, the metric has been revised to exclude call centre surveys and is presented with the revised calculation for prior periods. Internal reporting has reflected the revisions as of April 2005.

Recommendations		Management Action Plans
Relevance		
3.	<ul style="list-style-type: none"> <li data-bbox="245 1266 854 1465">❑ Management should ensure procedures and instructions for calculating the Index are documented. This should include sources of inputs, calculations to be performed and the order in which steps should be performed. 	<ul style="list-style-type: none"> <li data-bbox="886 1266 1505 1493">❑ Management agrees. All procedures and instructions for calculating the Customer Satisfaction Index will be documented. Sources of inputs, calculations performed, and the order in which they are performed will be duly noted. Completion by October 31, 2006.
4.	<ul style="list-style-type: none"> <li data-bbox="245 1514 854 1675">❑ Once the changes to the metric have been implemented, management should ensure that prior year comparisons are also amended in any reporting of this metric. 	<ul style="list-style-type: none"> <li data-bbox="886 1514 1505 1808">❑ Management agrees. To the extent possible, any prior year comparisons will be based on adjusting those prior year metrics to reflect the current method of calculating customer satisfaction. Where prior year metrics are not directly comparable, all differences between prior and current year metrics will be fully explained. Completion by October 31, 2006.

3. Corporate Policy Compliance Audit

3a Overview

- ❑ The Compliance Audit for the Distribution Line of Business included a review of compliance with corporate policies and procedures for key financial and management controls and business and travel expenses. We noted that the controls in place are generally satisfactory and policies and procedures are generally being followed. However, improvements are required in certain areas.

3b Compliance with Financial and Management Controls

- ❑ The scope of our review covered transactions during the 6-month period from June 1, 2005 to December 31, 2005 for the following five Cost Centres: Power Smart Outreach, Strategic Asset Management, Revenue Metering, North Shore Processing Center and Fraser Valley West Design.
- ❑ We reviewed management and financial controls in procurement, payroll, capital assets, conduct and ethics, information resources, financial reviews, and vehicle management.
- ❑ Financial and management controls are satisfactory and policies and procedures are followed within payroll, capital assets, financial reviews and vehicle management. However, our review noted improvements required in the following areas:
 - ◆ **Certain procurement policies were not consistently followed and exceptions were not detected by management controls.** We noted three contracts where the cumulative invoices exceeded the approved contract amount by \$55,465 (or 32%), \$5,986 (or 29%), and \$3,086 (or 3%) respectively. There were two instances of payments being made after the purchase orders had expired. One invoice was split in order to avoid the Local Purchase Stamp limit of \$10,000. In addition, purchasing reports for 6 individual months required for compliance reviews were not retained.
 - ◆ **Code of Conduct awareness and training needs improvement.** 36% of the employees sampled were not aware of the role of the Code of Conduct Advisor and 18% had not read the Code of Conduct.
 - ◆ **Non-compliance with certain IT policies.** 23% of employees sampled shared their user IDs and passwords with their co-worker(s).
 - ◆ **Awareness of time capture policies and timeliness of status changes need improvement.** 23% of employees sampled were not aware of the appropriate union policies related to weekly time reporting. The change of status of one employee was not performed until 65 days later.

3c Compliance with Business and Travel Expense Policies

- ❑ The scope of our review covered transactions during the 6-month period from June 1, 2005 to December 31, 2005, across the entire Distribution Line of Business. We reviewed 50 employee

3. Corporate Policy Compliance Audit

expense reports comprising 765 transactions, totaling \$132,976. We targeted our testing on areas believed to be high-risk (i.e. high dollars, and high out-of-pocket amounts).

- ❑ Overall, 11% of the transactions tested (value of \$50,509) were not in accordance with corporate policies or were not submitted and approved in an appropriate manner. Some of these transactions had multiple exceptions.
- ❑ Key exceptions included the following:
 - ◆ 26 transactions totaling \$20,192 were not supported by adequate business reasons;
 - ◆ 15 transactions totaling \$13,476 were not supported by original receipts;
 - ◆ 11 transactions totaling \$1,815 were for non-reimbursable items.
 - ◆ 5 transactions totaling \$6,414 were for hotel accommodations for which rates were greater than approved government rates. Consequently, BC Hydro overpaid by \$1,267.

	Recommendations	Management Action Plans
1.	<ul style="list-style-type: none"> ❑ Managers should ensure that staff are familiar with and comply with the following Corporate policies: <ul style="list-style-type: none"> ◆ Purchasing (especially monitoring payments made on a Purchase Order or Contract Order and those for Local Purchasing of Goods & Services); ◆ Information Security; ◆ Code of Conduct; and ◆ Time Capture and Reporting. 	<ul style="list-style-type: none"> ❑ Management agrees. Managers will ensure that department staff reviews the noted policies and that staff are familiar with and comply with these policies.
2.	<ul style="list-style-type: none"> ❑ Detailed reports of audit exceptions for each Cost Centre will be provided to the Senior Vice President and the Distribution Group Controller. The Group Controller should follow-up on the policy exceptions with the respective departments where considered necessary and: <ul style="list-style-type: none"> ◆ Ensure they understand the policies and the reasons why they are necessary. ◆ For those departments with a high number of exceptions, consider performing spot checks to monitor future compliance. 	<ul style="list-style-type: none"> ❑ Management agrees. The Distribution Group Controller will review the exception details and consider appropriate actions where necessary based on volume and severity or exceptions in respective departments. Expected completion by September 30, 2006.

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7.0 Reference: Exhibit B-15, Attachment 5, Annual Audit Plan, pages 7 to 9

3.7.4 The table in Section 4, page 8, states that Load Forecasting will be audited in F2007. Please provide that audit report, and management's responses, as soon as they are available.

RESPONSE:

The Load Forecasting Audit will not be finalized until the fourth quarter of F2007. In light of the schedule established by BCUC Order No. G-96-06 for the hearing of this application, and except for direct witness testimony and potentially rebuttal evidence in accordance with that schedule, BC Hydro does not anticipate filing any further evidence in this proceeding after these IR responses.

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British Columbia Hydro & Power Authority BC Hydro F07/F08 Revenue Requirements Application - Evidentiary Update	Exhibit: B-18

7.0 Reference: Exhibit B-15, Attachment 5, Annual Audit Plan, pages 7 to 9

3.7.5 The table in Section 5, page 9, states that Generation Asset Management was audited in F2005 and will be again in F2007. Please provide copies of those audit reports, and responses, as soon as they are available.

RESPONSE:

There will not be an audit of Generation Asset Management in F2007, but there will be an audit of Load Forecasting in F2007.

The Generation Asset Management audit report completed in F2005, which includes management's response, was provided in the response to BCUC IR 1.83.2.