



EPCOR  
Power L.P.

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## EPCOR Power L.P. reports third quarter results

**Edmonton, Alberta** – October 28, 2008 (TSX: EP.UN) - EPCOR Power Services Ltd., the general partner of EPCOR Power L.P. (the Partnership), today released the Partnership's quarterly results for the period ended September 30, 2008.

"Cash provided by operating activities of \$21.5 million in the third quarter was in line with our expectations," said Brian Vaasjo, President of the General Partner of EPCOR Power L.P. "Excluding working capital changes of \$19.5 million, cash provided by operating activities was \$41.0 million. The net loss in the quarter was a result of fair value changes, primarily on our natural gas contracts, substantially offsetting previous gains in the first two quarters of the year. We expect that we will continue to see volatility in our earnings due to the accounting requirements around fair value measurement which is not representative of the underlying economic performance of the business. During the quarter, we have continued to execute on our strategic objectives, announcing the acquisition of the Morris cogeneration facility and the commencement of a sales process for our interest in Primary Energy Recycling Holdings (PERH). Pending successful completion of these transactions, we believe the Morris acquisition will strengthen our portfolio of high quality contracted power assets and the sale of PERH will allow redeployment of cash to other potential investments. The current market turmoil impacting global capital markets has negatively impacted our unit price, however our business remains financially sound. The Partnership has strong liquidity with access to \$300 million on existing credit lines and no significant near-term debt maturities."

Highlights of EPCOR Power L.P.'s operational and financial performance included:

<b>Operational and Financial Highlights</b> <i>(unaudited)</i>	<b>Three months ended</b> <b>September 30</b>		<b>Nine months ended</b> <b>September 30</b>	
	<b>2008</b>	2007	<b>2008</b>	2007
<i>(millions of dollars except per unit and operational amounts)</i>				
Power generated (GWh)	<b>1,277</b>	1,630	<b>3,646</b>	4,080
Weighted average plant availability	<b>96%</b>	97%	<b>92%</b>	93%
Revenue	<b>138.0</b>	153.4	<b>406.7</b>	461.6
Net income (loss)	<b>(153.0)</b>	(15.9)	<b>5.3</b>	(14.5)
Per unit	<b>\$(2.84)</b>	\$(0.29)	<b>\$0.10</b>	\$(0.28)
Comprehensive income (loss)	<b>(154.0)</b>	(16.7)	<b>2.4</b>	(17.1)
Cash provided by operating activities	<b>21.5</b>	26.5	<b>104.8</b>	95.0
Per unit <sup>(1)</sup>	<b>\$0.40</b>	\$0.49	<b>\$1.94</b>	\$1.84
Cash distributions	<b>34.0</b>	33.9	<b>101.9</b>	99.3
Per unit	<b>\$0.63</b>	\$0.63	<b>\$1.89</b>	\$1.89
Capital expenditures	<b>6.4</b>	2.6	<b>21.9</b>	7.9
Weighted average units outstanding (millions)	<b>53.9</b>	53.9	<b>53.9</b>	51.7

<sup>(1)</sup> Cash provided by operating activities per unit is a non-GAAP financial measure that is defined in the interim MD&A.

The September 30, 2008 interim report is shown below. The interim management discussion and analysis and interim consolidated financial statements are available on the EPCOR Power L.P. website ([www.epcorpowlp.ca](http://www.epcorpowlp.ca)) and will be available on SEDAR ([www.sedar.com](http://www.sedar.com)).

# EPCOR Power L.P.

## Management's Discussion and Analysis

### For the Nine Months Ended September 30, 2008

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This management's discussion and analysis (MD&A), dated October 28, 2008, should be read in conjunction with the unaudited interim consolidated financial statements of EPCOR Power L.P. (the Partnership) for the nine months ended September 30, 2008 and the audited consolidated financial statements and MD&A of the Partnership for the year ended December 31, 2007. Additional information relating to the Partnership, including the 2007 Annual Information Form and continuous disclosure documents are available on SEDAR at [www.sedar.com](http://www.sedar.com). This discussion contains certain forward-looking information and readers are advised to read this discussion in conjunction with the cautionary statement regarding forward-looking information and statements on page 26 of this report.

EPCOR Power Services Ltd., the General Partner of the Partnership, a wholly-owned subsidiary of EPCOR Utilities Inc. (collectively with its subsidiaries, EPCOR), is responsible for management of the Partnership. The Board of Directors of the General Partner declares the cash distributions to the Partnership's unitholders. The General Partner has engaged certain other EPCOR subsidiaries (collectively, the Manager) to perform management and administrative services for the Partnership and to operate and maintain the power plants pursuant to management and operations agreements. The Audit Committee of the Board of Directors of the General Partner is to review and approve the interim MD&A of the Partnership in accordance with the Audit Committee's terms of reference. The Audit Committee has reviewed and approved the contents of this interim MD&A.

#### CONSOLIDATED RESULTS OF OPERATIONS

<i>(millions of dollars)(unaudited)</i>	<b>Three months</b>	<b>Nine months</b>
<b>Cash provided by operating activities for the three and nine months ended September 30, 2007</b>	<b>26.5</b>	<b>95.0</b>
Changes in operating working capital	(11.3)	(0.7)
Lower operating margin at Northwest US plants	(7.1)	(8.7)
Lower Castleton operating margin after PPA expiry	(2.4)	(2.4)
Net realized losses on foreign exchange and interest rate contracts in 2007	8.1	17.7
Higher (lower) operating margin at the Ontario plants	3.3	(2.5)
Higher operating margin at the California plants	2.6	3.2
Higher (lower) revenues at hydro facilities	1.2	(1.5)
Lower interest expenses	0.6	8.7
Mamquam maintenance outage in 2007	-	2.2
Mamquam and Queen Charlotte arbitration award	-	(1.8)
Preferred share dividends	-	(2.7)
Other	-	(1.7)
<b>Cash provided by operating activities for the three and nine months ended September 30, 2008</b>	<b>21.5</b>	<b>104.8</b>

The Partnership reported cash provided by operating activities of \$21.5 million or \$0.40 per unit for the quarter ended September 30, 2008 compared to \$26.5 million or \$0.49 per unit for the

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same period in 2007. Cash provided by operating activities per unit is defined below under Non-GAAP Measures. The \$5.0 million decrease in cash provided by operating activities for the third quarter of 2008 compared to the third quarter of 2007 is primarily due to the following:

- A \$19.5 million increase in working capital in the third quarter of 2008 compared to a \$8.2 million increase in same period in 2007. The three months ended September 30, 2008 include the receipt of two months of sales at Oxnard compared to the receipt of three months of sales in the third quarter of 2007. In addition, the Partnership reduced an accrual for natural gas purchases in Ontario in third quarter of 2008;
- A decrease in operating margin of \$7.1 million at the Northwest US plants due to a milestone payment at Frederickson under its long-term service agreement with the turbine manufacturer, lower revenue and generation at Manchief due to higher natural gas prices in Colorado and higher fuel costs at Greeley to meet minimum generation requirements in its power purchase contract (PPA); and
- Operating margin at Castleton was \$2.4 million lower compared to the same quarter last year as margins have been lower after its PPA expired in June 2008, consistent with previously disclosed expectations.

Decreases were partially offset by the following:

- In the third quarter of 2007, net losses of \$8.1 million were realized on foreign exchange and interest rate contracts that were entered into in anticipation of permanent financing of acquisitions completed in 2006;
- Operating margin at the Ontario plants was \$3.3 million higher compared to the prior year’s quarter as a result of a \$3.4 million reduction in natural gas costs as we updated our estimate of the cost for natural gas supplied under contract. These increases were partially offset by a 19% increase in the natural gas prices in 2008 at Kapuskasing and North Bay under the 20 year supply agreements;
- Operating margin at the California plants was \$2.6 million higher due to increased electricity prices driven by higher natural gas prices, partially offset by higher fuel costs and higher maintenance costs due to turbine repairs at North Island;
- Revenues at the hydro facilities were \$1.2 million higher compared to the third quarter of 2007 due to higher water flow at Curtis Palmer, partially offset by a planned maintenance outage at one of the Curtis Palmer units and lower water flow at Mamquam. Water flow at Mamquam was lower than the prior year, but above historic levels; and
- Lower interest expenses of \$0.6 million primarily due to the replacement of capital lease obligations with lower cost long-term debt in the third quarter of 2007.

The Partnership reported cash provided by operating activities of \$104.8 million or \$1.94 per unit for the nine months ended September 30, 2008 compared with \$95.0 million or \$1.84 per unit for the same period in 2007. Cash provided by operating activities per unit is defined below under Non-GAAP Measures. The \$9.8 million increase in cash provided by operating activities compared to 2007 is primarily due to the items described above for the current quarter, as well as the following items:

- Lower interest expenses of \$8.7 million primarily due to the pay down of debt with the proceeds from the issue of Partnership units and preferred shares in the second quarter of 2007; and
- A maintenance outage at the Mamquam facility to effect tunnel repairs in the second quarter of 2007 resulted in higher maintenance costs of approximately \$2.2 million compared to the same period in 2008.

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Increases were partially offset by the following:

- Operating margin at the Ontario plants was \$2.5 million lower due to the items discussed above for the current quarter as well as: (i) lower generation and revenue at Calstock due to high moisture levels in the waste wood inventory and lower inventory levels which caused Calstock to scale back production in 2008 to optimize available waste wood, (ii) lower waste heat availability and higher waste heat optimization costs due to lower throughput on TransCanada Corporation’s (TransCanada) Canadian Mainline, and (iii) the settlement of natural gas supply contract disputes at Tunis in July 2007 and January 2008;
- Arbitration awards against the previous owners of Mamquam and Queen Charlotte in respect of claims by the Partnership in the purchase and sale agreement were \$2.3 million in the second quarter of 2007 compared with \$0.5 million awarded in the first quarter of 2008; and
- Dividends on preferred shares issued in May 2007 by a subsidiary company of the Partnership were \$4.9 million for the nine months ended September 30, 2008 compared to \$2.2 million for the same period in 2007.

<i>(millions of dollars)(unaudited)</i>	<b>Three Months</b>	<b>Nine months</b>
<b>Net loss for the three and nine months ended September 30, 2007</b>	<b>(15.9)</b>	<b>(14.5)</b>
Fair value changes on natural gas supply, foreign exchange and interest rate contracts	(129.9)	39.9
Foreign exchange losses in 2008 compared to gains in 2007 <sup>(1)</sup>	(39.9)	(102.4)
Lower operating margin at Northwest US plants	(7.1)	(8.7)
Lower Castleton operating margin after PPA expiry	(2.4)	(2.4)
Higher enhancement fee	(0.8)	(1.6)
Decrease in income tax expense	22.7	79.6
Asset impairment charge in 2007	13.0	13.0
Higher (lower) operating margin at the Ontario plants	3.3	(2.5)
Higher operating margin at the California plants	2.6	3.2
Higher (lower) revenues at hydro facilities	1.2	(1.5)
Lower interest expenses <sup>(1)</sup>	0.6	8.7
Mamquam maintenance outage in 2007	-	2.2
Mamquam and Queen Charlotte arbitration award	-	(1.8)
Preferred share dividends	-	(2.7)
Other	(0.4)	(3.2)
<b>Net (loss) income for the three and nine months ended September 30, 2008</b>	<b>(153.0)</b>	<b>5.3</b>

<sup>(1)</sup> Excluding changes in the fair value of foreign exchange and interest rate contracts.

Net loss was \$153.0 million or \$2.84 per unit for the three months ended September 30, 2008 compared to \$15.9 million or \$0.29 per unit for the same period in 2007. In addition to the items described above for the change in cash provided by operating activities, the increase in net loss of \$137.1 million was the result of:

- A net loss of \$175.0 million recorded in the third quarter of 2008 on the change in the fair value of the natural gas supply and foreign exchange contracts compared to a net loss of \$45.1 million on natural gas supply, foreign exchange and interest rate contracts in the third quarter of 2007 (see Gains (Losses) on Derivative Instruments). The majority of the changes in fair value are the result of a larger decrease in the future market prices for natural gas in the third quarter of 2008 compared the third quarter of 2007; and

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- Foreign exchange losses of \$15.8 million in the third quarter of 2008 compared to gains of \$24.1 million for the same period in 2007. The foreign exchange losses recorded in the third quarter of 2008 were the result of a weakening of the Canadian dollar of \$0.045 relative to the United States (US) dollar during the quarter on the translation of US dollar-denominated debt, compared to a strengthening of \$0.071 for the same period in 2007.

The items that increased the net loss were partially offset by the following:

- An income tax recovery of \$21.9 million was recorded in the third quarter of 2008 primarily related to the future income taxes that resulted from changes in the temporary differences expected to reverse after 2010 that will be subject to the Specified Investment Flow Through (SIFT) taxes; and
- An asset impairment charge of \$13.0 million in the third quarter of 2007 attributed to the management agreement between a subsidiary of the Partnership and Primary Energy Recycling Holdings LLC (PERH), Primary Energy Recycling Corporation (PERC) and Primary Energy Operations LLC.

Net income was \$5.3 million or \$0.10 per unit for the nine months ended September 30, 2008 compared to a net loss of \$14.5 million or \$0.28 per unit for the same period in 2007. The increase in net income of \$19.8 million is primarily due to the items described above for the current quarter, as well as the following item:

- A change in tax law in the second quarter of 2007, which will result in the Partnership’s Canadian operations becoming taxable in 2011, resulted in the recording of a future income tax expense of \$75.5 million.

<b>OPERATING MARGIN<sup>(1)</sup></b> <i>(millions of dollars)(unaudited)</i>	<b>Three months</b>		<b>Nine months</b>	
	<b>ended September 30</b>		<b>ended September 30</b>	
	<b>2008</b>	2007	<b>2008</b>	2007
Ontario	<b>17.5</b>	14.2	<b>51.2</b>	53.7
Williams Lake	<b>7.7</b>	6.9	<b>18.8</b>	19.5
Mamquam and Queen Charlotte	<b>3.1</b>	3.3	<b>8.8</b>	7.4
Northwest US plants	<b>4.7</b>	11.8	<b>21.6</b>	30.3
California plants	<b>16.5</b>	13.9	<b>29.1</b>	25.9
Curtis Palmer	<b>4.5</b>	2.9	<b>20.9</b>	21.0
Northeast US gas plants	<b>0.2</b>	2.9	<b>5.9</b>	9.0
North Carolina plants	<b>1.5</b>	2.7	<b>2.6</b>	3.0
PERC management fee	<b>0.6</b>	0.2	<b>1.8</b>	1.4
	<b>56.3</b>	58.8	<b>160.7</b>	171.2
Fair value changes				
Foreign exchange contracts	<b>(14.6)</b>	14.5	<b>(23.9)</b>	37.7
Natural gas supply contracts	<b>(160.5)</b>	(52.7)	<b>9.8</b>	(68.2)
	<b>(118.8)</b>	20.6	<b>146.6</b>	140.7

<sup>(1)</sup> Operating margin is not a defined financial measure according to Canadian GAAP, and does not have a standardized meaning prescribed by GAAP. See Non-GAAP Measures.

Operating margin excluding fair value changes in foreign exchange and natural gas supply contracts for the three and nine months ended September 30, 2008 decreased by \$2.5 million and \$10.5 million compared to the same periods in 2007. The decrease in operating margin was

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primarily due to lower operating margin at the Northwest US plants due to a milestone payment at Frederickson under its long-term service agreement with the turbine manufacturer, lower revenue and generation at Manchief as a result of higher natural gas prices in Colorado and higher fuel costs at Greeley to meet minimum generation requirements in its PPA.

Unrealized fair value changes in derivative instruments recorded for accounting purposes are not representative of their economic value when considering them in conjunction with the economically hedged item such as future natural gas purchases or future power sales.

### NON-GAAP MEASURES

The Partnership uses operating margin as a performance measure and cash provided by operating activities per unit as a cash flow measure. These terms are not defined financial measures according to Canadian generally accepted accounting principles (GAAP) and do not have standardized meanings prescribed by GAAP. Therefore, these measures may not be comparable to similar measures presented by other enterprises.

The Partnership uses operating margin to measure the financial performance of plants and groups of plants. A reconciliation from operating margin to net income before tax and preferred share dividends is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months		Nine months	
	ended September 30	ended September 30	ended September 30	ended September 30
	2008	2007	2008	2007
Operating margin	<b>(118.8)</b>	20.6	<b>146.6</b>	140.7
Deduct (Add):				
Depreciation and amortization	<b>23.1</b>	23.0	<b>70.0</b>	68.8
Management and administration	<b>4.7</b>	3.8	<b>13.2</b>	9.7
Foreign exchange losses (gains)	<b>15.8</b>	(24.1)	<b>26.2</b>	(56.3)
Equity losses in PERH	<b>1.7</b>	1.7	<b>3.8</b>	2.7
Financial charges and other, net	<b>9.2</b>	16.7	<b>27.4</b>	39.7
Asset impairment charge	-	13.0	-	13.0
Net income before tax and preferred share dividends	<b>(173.3)</b>	(13.5)	<b>6.0</b>	63.1

Cash provided by operating activities per unit is cash provided by operating activities (a GAAP defined measure) divided by the weighted average number of units outstanding in the period. The composition of these measures is consistent with December 31, 2007 reporting.

### SIGNIFICANT EVENTS

#### Morris acquisition

On September 11, 2008, the Partnership announced an agreement to acquire a 100% equity interest in Morris Cogeneration LLC (Morris) from Diamond Generating Corporation and MIC Nebraska, Inc., both wholly-owned subsidiaries of Mitsubishi Corporation for an aggregate purchase price of US\$73 million subject to finalizing closing adjustments. The purchase price is lower than the previously disclosed amount of US\$77 million as preliminary closing adjustments have been determined. Morris is a 177 megawatt natural gas-fired cogeneration facility located on Equistar Chemicals LP's (Equistar) chemical plant in Morris, Illinois.

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The acquisition is expected to close in the fourth quarter of 2008 and will be financed under the Partnership's existing credit facilities with permanent long-term financing to be arranged after the close of the transaction, depending on the requirements of the Partnership.

All of the steam and a portion of the electricity produced from Morris are sold to Equistar under the terms of a long-term energy services agreement which expires in 2023. Equistar, a wholly-owned subsidiary of Lyondell Chemical Company, produces ethylene and its co-products and derivatives including polyethylene plastic, at its plant in Morris. Morris also has an electric capacity agreement with Exelon Generation Company, LLC (Exelon) that terminates in 2011, for capacity and electricity of 100 MW. Any excess capacity and energy above the needs of Exelon and Equistar can be sold into the Pennsylvania, New Jersey, and Maryland market.

### **Sale of PERH**

On September 24, 2008, the Partnership and PERC announced they are undertaking a sale process that could lead to the sale of PERC and/or PERH. PERC and the Partnership have also agreed to terms on the termination of the PERC management agreement subject to a successful sale. There can be no assurance that the sales process will ultimately result in any transaction.

### **Kenilworth PPA extension**

The Partnership reached an agreement with Schering Corporation (Schering) to amend the Kenilworth PPA effective July 1, 2008 and extend it to July 2012. The previous PPA under which the Kenilworth facility sold electrical energy and steam to Schering was due to expire in September 2009. Future operating margins are expected to be similar to current levels under the terms of the revised agreement, which includes amendments that eliminate early termination provisions and provide for the sharing of potential cost saving benefits by both parties.

## **CHANGES IN ACCOUNTING POLICIES**

Commencing January 1, 2008, the Partnership adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants (CICA) for Capital Disclosures, Financial Instruments – Disclosures and Presentation and Inventories. The changes and the impact of these changes on the Partnership’s consolidated financial statements are described in Note 2 to the interim consolidated financial statements. The new accounting standards have been applied prospectively and the comparative financial statements have not been restated.

### **Capital disclosures**

The new accounting standard requires qualitative information about the Partnership’s objectives, policies and processes for managing capital and quantitative data on the Partnership’s capital, as discussed in Note 7 - Capital management of the Partnership’s interim consolidated financial statements.

### **Financial instruments – presentation and disclosures**

These new standards establish requirements for the reporting and presentation of quantitative and qualitative information that are intended to provide users of the financial statements with additional insight into the Partnership’s risks associated with financial instruments and how

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these risks are managed. These risks include credit, liquidity and market risks. The additional disclosures required under these new standards have been incorporated into the interim consolidated financial statements and discussed in Note 5 – Financial instruments and Note 6 – Risk management. Included in the financial statement disclosure is a sensitivity analysis of the impact on net income of changes in the underlying risk factors, primarily natural gas prices and foreign exchange rates, on the change in the fair value of financial instruments. Changes in the fair value of the natural gas contracts has limited economic impact on the Partnership as the majority of the gas supplied under long term contracts is used for power generation. Changes in the value of the foreign exchange contracts are offset by changes in the value of expected foreign currency cash flows. Therefore, readers should be cautious in assessing the disclosed sensitivities on the interim financial statements.

### **Inventories**

The new standard requires inventories to be measured at the lower of cost and net realizable value and did not materially impact the interim consolidated financial statements. The additional disclosures required under the new standard have been incorporated into the interim consolidated financial statements and discussed in Note 4 – Inventories.

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### REVENUE AND PLANT OUTPUT

(millions of dollars except GWh) (unaudited)	Three months ended September 30				Nine months ended September 30			
	GWh	2008	GWh	2007	GWh	2008	GWh	2007
Ontario plants								
- Power	266	\$ 26.2	326	\$ 29.1	888	\$ 92.4	1,023	\$ 95.0
- Enhancements		7.0		2.0		17.6		7.8
- Gas diversions		4.5		3.2		9.6		8.1
		37.7		34.3		119.6		110.9
Williams Lake								
- Firm energy	127	10.5	132	9.8	337	27.9	373	28.1
- Excess energy	5	0.2	9	0.4	18	0.9	33	1.4
	132	10.7	141	10.2	355	28.8	406	29.5
Mamquam and Queen Charlotte	68	4.1	69	4.2	182	12.2	193	13.0
Northwest US plants	305	16.0	482	16.9	611	44.8	651	46.2
California plants	205	45.6	269	37.9	674	116.5	769	105.7
Curtis Palmer	50	5.5	37	4.2	242	24.4	237	25.1
Northeast US gas plants	75	11.3	107	14.6	202	33.0	294	47.4
North Carolina plants	176	20.8	199	15.8	492	48.7	507	43.5
PERC management fees		0.9		0.8		2.6		2.6
Fair value changes		(14.6)		14.5		(23.9)		37.7
	1,277	\$ 138.0	1,630	\$ 153.4	3,646	\$ 406.7	4,080	\$ 461.6

Weighted average plant availability <sup>(1)</sup>	Three months ended September 30		Nine months ended September 30	
	2008	2007	2008	2007
Ontario plants	97%	91%	96%	94%
Williams Lake	98%	100%	87%	95%
Mamquam and Queen Charlotte	85%	89%	84%	76%
Northwest US plants	99%	98%	93%	94%
California plants	94%	95%	92%	92%
Curtis Palmer	57%	99%	85%	95%
Northeast US gas plants	99%	97%	78%	95%
North Carolina plants	100%	99%	98%	97%
Weighted average total	96%	97%	92%	93%

<sup>(1)</sup> Plant availability represents the percentage of time in the period that the plant is available to generate power, whether actually running or not, and is reduced by planned and unplanned outages.

Revenues were \$138.0 million and \$406.7 million for the three and nine months ended September 30, 2008 respectively compared to \$153.4 million and \$461.6 million for the same periods in 2007. The decreases were primarily due to changes in the fair value of foreign exchange contracts and lower natural gas sales at Castleton to utilize excess natural gas transmission capacity, partially offset by higher revenue at the California facilities as higher natural gas costs were passed on to PPA counterparties. Overall, the plants in the US realized higher US dollar revenue for the nine months ended September 30, 2008 compared to the same period in 2007, however lower Canadian to US dollar exchange rates resulted in a decrease in Canadian dollars. A portion of the impact of the lower Canadian to US dollar exchange rates was offset by higher gains realized on foreign exchange contracts used to hedge exposure to

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changes in the exchange rate. The realized gains were reflected in the revenues of the US plants.

### *Ontario Plants*

The Ontario plants reported revenues of \$37.7 million and \$119.6 million for the three and nine months ended September 30, 2008 compared to \$34.3 million and \$110.9 million for the same periods in the prior year. The increase was due to built-in annual price escalators and increased enhancement activity due to an increase in natural gas prices partially offset by lower generation and revenue at Calstock due to reduced fuel availability and high moisture levels in the waste wood inventory. As a result, the plant scaled back off-peak production to optimize available waste wood and used natural gas to meet minimum generation requirements. While wetter than normal conditions continued to have an impact on Calstock fuel quality in the third quarter, warmer temperatures and operational changes improved the wet wood issues during the quarter, in line with previous expectations.

Revenues at the Ontario facilities were also adversely impacted by lower waste heat availability which declined 8% and 15% for the three and nine months ended September 30, 2008 compared to the same periods in 2007 excluding the impact of the Kapuskasing outage in 2007. Lower throughput on the TransCanada Canadian Mainline, the natural gas transmission line to Northern Ontario, was the cause of the decline. This decrease was due to lower natural gas demand in Northern Ontario in part due to lower forestry industry activity, lower natural gas volumes leaving Alberta due to lower levels of natural gas supply from the Western Canadian Sedimentary Basin due to lower drilling activity combined with increasing demand in Alberta, structural changes in the nature of long haul transportation agreements on the TransCanada Canadian Mainline and the conversion of an upstream section on the TransCanada Canadian Mainline west of the Manitoba border from a high pressure natural gas line to an oil line. Future throughput will continue to be subject to supply and demand variances, however forecasts from independent third parties suggest a 10% to 20% decline in throughput in 2008 and 2009 from 2007 and marginal further declines after 2009 with potential for recovery of volumes beginning as early as 2012. Lower throughput on this natural gas transmission line also has an impact on natural gas transportation costs to the Partnership’s Ontario natural gas facilities (see Cost of Fuel).

### *Williams Lake*

Revenues at Williams Lake were \$10.7 million and \$28.8 million for the three and nine months ended September 30, 2008, compared with \$10.2 million and \$29.5 million for the same periods in 2007. The increase in revenue during the third quarter was due to higher pricing under terms of the PPA to offset the lower revenue in the second quarter of 2008 caused by a planned outage to complete a major overhaul. The higher pricing will continue in the fourth quarter of 2008. Generation and availability during the three months ended September 30, 2008 were lower than for the same period in the prior year due to wood handling constraints during repairs to a bulldozer.

### *Mamquam and Queen Charlotte*

Revenues at Mamquam and Queen Charlotte were \$4.1 million and \$12.2 million for the three and nine months ended September 30, 2008, compared with \$4.2 million and \$13.0 million for the same periods in 2007. The decrease in generation and revenue during the third quarter was due to lower water flow at Mamquam, which was lower than in the prior year but above historic levels as a result of the melting of above normal snow pack levels in British Columbia, which had adversely impacted generation and revenue during the first five months of 2008. The third

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quarter results are in line with previously disclosed expectations. Generation and revenues in 2007 were adversely impacted by tunnel maintenance completed at Mamquam.

### *Northwest US Plants*

Availability for the Northwest US plants for the nine months ended September 30, 2008 was lower than for the same period in 2007 due to planned outages at Manchief and Frederickson.

Revenues from Frederickson were \$6.2 million and \$17.5 million for the three and nine months ended September 30, 2008 consistent with \$6.1 million and \$17.6 million for the same periods in 2007.

Revenues from Greeley were \$2.4 million and \$7.4 million for the three and nine months ended September 30, 2008 consistent with \$2.4 million and \$7.1 million for the same periods in 2007.

Revenues from Manchief were \$7.4 million and \$19.9 million for the three and nine months ended September 30, 2008 compared to \$8.4 million and \$21.5 million for the same periods in 2007. The decreases were due to lower generation as a result of higher gas prices in Colorado and lower Canadian to US dollar exchange rates.

### *California Plants*

Revenues from the Naval facilities were \$33.8 million and \$92.1 million for the three and nine months ended September 30, 2008 compared to \$28.5 million and \$84.9 million for the same periods in 2007. The increases were due to increased US dollar electricity prices driven by higher natural gas prices partially offset by lower Canadian to US dollar exchange rates.

Revenues from Oxnard were \$11.8 million and \$24.4 million for the three and nine months ended September 30, 2008 compared to \$9.4 million and \$20.8 million for the same periods in 2007. The increases were due to increased US dollar electricity prices driven by higher natural gas prices partially offset by lower Canadian to US dollar exchange rates.

### *Curtis Palmer*

Revenues at Curtis Palmer were \$5.5 million and \$24.4 million for the three and nine months ended September 30, 2008 compared with \$4.2 million and \$25.1 million for the same periods in 2007. Generation and revenues for the three months ended September 30, 2008 were both higher than the same period in the prior year due to higher water flow partially offset by a planned maintenance outage at one of the Palmer units. Revenues for the nine months ended September 30, 2008 were consistent with the same period in the prior year.

### *Northeast US Gas Plants*

Revenues at Castleton were \$4.7 million and \$11.9 million for the three and nine months ended September 30, 2008 compared with \$8.8 million and \$26.6 million for the same periods in 2007. Effective July 1, 2008, the PPA for Castleton expired and the Partnership began running the plant on a merchant basis. The Partnership is evaluating its longer term options for the facility including continuing to run the plant on a merchant basis or selling the facility. Under a merchant scenario, operating margins have declined and are expected to be lower and more volatile than they were under the pre-existing PPA. Revenues for the three and nine months ended September 30, 2007 were comprised of capacity sales under the pre-existing PPA and natural gas sales to utilize excess natural gas transmission capacity. The natural gas sales were largely matched by natural gas costs (see Cost of Fuel). A major overhaul was completed at

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Castleton in the second quarter of 2008, which reduced generation and availability but did not impact capacity revenues.

Revenues from Kenilworth were \$6.6 million and \$21.1 million for the three and nine months ended September 30, 2008 compared to \$5.8 million and \$20.8 million for the same periods in 2007. The increase during the three months ended September 30, 2008 compared to the same period in the prior year was due to higher prices for steam sales driven by higher natural gas prices. Revenues for the nine months ended September 30, 2008 were consistent with the same period in the prior year.

### *North Carolina Plants*

Revenues from the North Carolina plants were \$20.8 million and \$48.7 million for the three and nine months ended September 30, 2008 compared to \$15.8 million and \$43.5 million for the same periods in 2007. The increases were the result of increased US dollar electricity prices driven by higher coal prices partially offset by lower dispatch and lower Canadian to US dollar exchange rates.

### *Fair value changes on foreign exchange contracts*

Unrealized losses on foreign exchange contracts were \$14.6 million and \$23.9 million for the three and nine months ended September 30, 2008 respectively compared to unrealized gains of \$14.5 million and \$37.7 million reported for the same periods in 2007. The changes in fair value were primarily due to changes in the forward prices for Canadian dollars relative to US dollars which increased \$0.041 and \$0.061 for the three and nine months ended September 30, 2008 respectively compared to decreases of \$0.059 and \$0.141 for the same periods in 2007.

<b>COST OF FUEL</b>	<b>Three months ended</b>		<b>Nine months ended</b>	
	<b>September 30</b>		<b>September 30</b>	
<i>(millions of dollars)(unaudited)</i>	<b>2008</b>	<b>2007</b>	<b>2008</b>	<b>2007</b>
<b>Ontario Plants</b>				
Natural gas	<b>14.6</b>	15.2	<b>48.7</b>	42.7
Waste heat	<b>1.3</b>	0.9	<b>6.3</b>	1.9
Wood waste	<b>0.6</b>	0.4	<b>2.1</b>	1.5
	<b>16.5</b>	16.5	<b>57.1</b>	46.1
<b>Williams Lake - wood waste</b>	<b>0.8</b>	0.8	<b>2.0</b>	2.6
<b>Northwest US Plants - natural gas</b>	<b>2.8</b>	2.2	<b>8.8</b>	7.5
<b>California Plants - natural gas</b>	<b>23.6</b>	18.6	<b>70.7</b>	63.6
<b>Northeast US Gas Plants - natural gas</b>	<b>9.2</b>	10.2	<b>21.8</b>	33.0
<b>North Carolina Plants - coal, tire-derived fuel &amp; wood waste</b>	<b>15.3</b>	9.9	<b>34.4</b>	28.7
<b>Fair value changes on natural gas contracts</b>	<b>160.5</b>	52.7	<b>(9.8)</b>	68.2
	<b>228.7</b>	110.9	<b>185.0</b>	249.7

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Fuel costs, which are the Partnership’s most significant cost of operations, include commodity costs, transportation costs and fair value changes on natural gas supply contracts. Virtually all the fuel for Ontario and Williams Lake is supplied under fixed price, long-term supply agreements with built-in price escalators that generally correspond to price increases under the related PPAs.

For the three and nine months ended September 30, 2008, fuel costs, excluding fair value changes on natural gas contracts, were \$68.2 million and \$194.8 million compared with \$58.2 million and \$181.5 million for the same periods in 2007. The Partnership recorded fair value losses on the natural gas supply contracts of \$160.5 million and gains of \$9.8 million for the three and nine months ended September 30, 2008 compared to fair value losses of \$52.7 million and \$68.2 million for the same periods in 2007. The changes in the fair value of the natural gas contracts were primarily due to changes in natural gas forward prices which decreased \$2.69/gigajoule (GJ) and increased \$0.26/GJ for the three and nine months ended September 30, 2008 compared to decreases of \$0.71/GJ and \$0.47/GJ for the same periods in 2007. Fair value changes were also impacted by the receipt of natural gas under the contracts, increases in the pricing applied to natural gas supply at Tunis in the second quarter of 2007 and decreases in the pricing applied to natural gas supply in the third quarter of 2008.

Fuel costs at the Ontario plants for the three and nine months ended September 30, 2008 were \$16.5 million and \$57.1 million compared to \$16.5 million and \$46.1 million for the same periods in 2007. The increase in the year to date fuel costs was due to (i) higher fuel supply costs at Tunis as a result of supply contract dispute settlements in July 2007 and January 2008; (ii) a 19% increase in the fuel supply price in 2008 at Kapuskasing and North Bay under the 20 year natural gas supply agreements; (iii) an increase in waste heat optimization costs in the second quarter of 2008 due to continued decreases in natural gas flow on the TransCanada Canadian Mainline; (iv) a \$1.2 million refund of natural gas transportation costs recorded in the first quarter of 2007 relating to prior periods; and (v) higher natural gas consumption at Calstock in 2008 to ensure minimum generation requirements were met. These increases were partially offset by a \$3.4 million reduction in natural gas costs as we updated our estimate of the cost for natural gas supplied under contract.

On March 28, 2008, the National Energy Board of Canada approved an increase in the tariff for natural gas transportation costs on the TransCanada Canadian Mainline from \$1.03/GJ to \$1.38/GJ effective April 1, 2008. On July 27, 2008, a further increase to \$1.40/GJ was approved effective July 1, 2008. These changes are expected to increase the fuel costs at the Ontario natural gas facilities by approximately \$2 million in 2008 over 2007 costs.

Williams Lake incurred fuel costs of \$0.8 million and \$2.0 million for the three and nine months ended September 30, 2008, compared to \$0.8 million and \$2.6 million for the same periods in 2007. The decreases were due primarily to lower waste wood consumption during a planned outage in the second quarter of 2008.

The Northwest US plants incurred fuel costs of \$2.8 million and \$8.8 million for the three and nine months ended September 30, 2008, compared to \$2.2 million and \$7.5 million for the same periods in 2007. The increases were due to an increase in fuel costs at Greeley to meet minimum generation requirements in its PPA partially offset by lower Canadian to US dollar exchange rates. On October 23, 2008, the Manager on behalf of the Partnership entered into a three year financial natural gas swap contract that covers most of the anticipated supply

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requirements for Greeley which is expected to result in positive operating margin from the facility based on the PPA terms.

Fuel costs at the California facilities were \$23.6 million and \$70.7 million for the three and nine months ended September 30, 2008 compared to \$18.6 million and \$63.6 million for the same periods in 2007. The increases were due to higher natural gas prices partially offset by lower Canadian to US dollar exchange rates.

The Northeast US gas plants incurred fuel costs of \$9.2 million and \$21.8 million for the three and nine months ended September 30, 2008, compared to \$10.2 million and \$33.0 million for the same periods in 2007. The decreases were due to lower sales of natural gas to utilize excess natural gas transmission capacity at Castleton and lower Canadian to US dollar exchange rates partially offset by natural gas consumed by Castleton for merchant power generation in the third quarter of 2008 and higher natural gas prices at Kenilworth in 2008.

The North Carolina plants incurred fuel costs of \$15.3 million and \$34.4 million for the three and nine months ended September 30, 2008, compared to \$9.9 million and \$28.7 million for the same periods in 2007. The increases were due to higher coal prices partially offset by lower Canadian to US dollar exchange rates.

The Curtis Palmer, Mamquam and Queen Charlotte hydroelectric plants do not have fuel costs.

<b>OPERATING AND MAINTENANCE EXPENSE</b>	<b>Three months ended</b>		<b>Nine months ended</b>	
	<b>September 30</b>		<b>September 30</b>	
<i>(millions of dollars)(unaudited)</i>	<b>2008</b>	<b>2007</b>	<b>2008</b>	<b>2007</b>
Ontario	<b>3.6</b>	3.4	<b>10.5</b>	10.2
Williams Lake	<b>1.5</b>	1.4	<b>4.4</b>	4.3
Mamquam and Queen Charlotte	<b>0.3</b>	0.3	<b>1.0</b>	0.9
Northwest US plants	<b>7.6</b>	2.2	<b>11.9</b>	6.3
California plants	<b>3.2</b>	3.1	<b>9.7</b>	10.3
Curtis Palmer	<b>0.4</b>	0.3	<b>1.1</b>	0.9
Northeast US gas plants	<b>1.2</b>	1.2	<b>3.7</b>	3.9
North Carolina plants	<b>3.2</b>	2.8	<b>9.3</b>	8.6
PERC management expenses	<b>0.2</b>	0.2	<b>0.7</b>	0.7
	<b>21.2</b>	14.9	<b>52.3</b>	46.1

Operating and maintenance expenses are payable to the Manager for the operation and routine maintenance of the plants. Fees are based on fixed charges adjusted annually for inflation for the Canadian plants, Curtis Palmer, Manchief and Castleton and a flow through of costs for the remaining US plants. Operating and maintenance expenses were \$21.2 and \$52.3 million for the three and nine months ended September 30, 2008, compared to \$14.9 million and \$46.1 million for the same periods in 2007. The increase is primarily due to a milestone payment at Frederickson under its long-term service agreement with the turbine manufacturer.

**OTHER PLANT OPERATING EXPENSES**

Other plant operating expenses, which include insurance, property taxes and major maintenance expenses, were \$6.9 million and \$22.8 million for the three and nine months ended September 30, 2008 compared to \$7.0 million and \$25.1 million for the same periods in 2007. The decrease in year to date costs was mainly due to the Mamquam tunnel repairs in 2007, partially offset by an increase in major maintenance costs at Williams Lake during the annual maintenance overhaul completed in the second quarter of 2008 and turbine repairs at North Island in the second and third quarters of 2008.

An inspection at Oxnard in September 2008 identified damage to the gas turbine. A lease unit has been installed and the damage to the gas turbine is being assessed. The expected cost of the repair is in the range of \$3 million to \$4 million and may be covered by insurance and/or warranty from the company who recently performed maintenance on the turbine. The lease unit costs of \$0.1 million per month may be covered by business interruption insurance after a 45 day waiting period, if it is determined to be an insurable event.

**DEPRECIATION AND AMORTIZATION**

Depreciation and amortization expense for the three and nine months ended September 30, 2008 was \$23.1 million and \$70.0 million consistent with \$23.0 million and \$68.8 million for the same periods in 2007.

**MANAGEMENT AND ADMINISTRATION**

Management and administration costs, which include fees payable to EPCOR and general and administrative costs, were \$4.7 million and \$13.2 million for the three and nine months ended September 30, 2008 compared to \$3.8 million and \$9.7 million for the same periods in 2007. The increases were due to higher enhancement fees paid to EPCOR as a result of higher enhancement profits and arbitration awards against the previous owners of Mamquam and Queen Charlotte in respect of claims by the Partnership in the purchase and sale agreement of \$2.3 million in the second quarter of 2007 compared with \$0.5 million awarded in the first quarter of 2008.

<b>FOREIGN EXCHANGE LOSSES (GAINS)</b>	<b>Three months ended</b>		<b>Nine months ended</b>	
<i>(millions of dollars)(unaudited)</i>	<b>September 30</b>	<b>September 30</b>	<b>September 30</b>	<b>September 30</b>
	<b>2008</b>	<b>2007</b>	<b>2008</b>	<b>2007</b>
Realized foreign exchange (gains) losses	<b>(0.1)</b>	2.9	<b>(0.8)</b>	3.9
Unrealized foreign exchange losses (gains) on US dollar-denominated debt	<b>16.0</b>	(27.0)	<b>26.9</b>	(80.2)
Realized (gains) losses on foreign exchange contracts	<b>(0.1)</b>	-	<b>0.1</b>	15.3
Fair value changes on foreign exchange contracts	-	-	-	4.7
	<b>15.8</b>	(24.1)	<b>26.2</b>	(56.3)

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The Partnership reported net foreign exchange losses of \$15.8 million and \$26.2 million for the three and nine months ended September 30, 2008 compared to gains of \$24.1 million and \$56.3 million for the same periods in 2007. The foreign exchange losses recorded in the three and nine months ended September 30, 2008 were the result of a weakening of the Canadian dollar of \$0.045 and \$0.073 relative to the US dollar on the translation of US dollar-denominated debt, compared to a strengthening of \$0.071 and \$0.171 for the same periods in 2007.

During the first two quarters of 2007, the Partnership realized losses of \$15.3 million on settlement of foreign exchange contracts entered into in anticipation of the issuance of Canadian equity to replace a portion of the US dollar bridge acquisition facility.

### EQUITY LOSSES IN PERH

Equity losses in PERH were from the Partnership’s 17.0% common ownership interest in PERH, which is accounted for on an equity basis. For the three and nine months ended September 30, 2008, the Partnership received dividends on its 14.2% preferred ownership interest of \$0.5 million and \$1.4 million respectively (\$0.4 million and \$1.2 million for the same periods in 2007) and dividends from its common interest in PERH of \$0.8 million and \$2.4 million respectively (\$0.5 million and \$2.8 million for the same periods in 2007).

<b>FINANCIAL CHARGES AND OTHER, NET</b>	<b>Three months ended</b>		<b>Nine months ended</b>	
	<b>September 30</b>		<b>September 30</b>	
<i>(millions of dollars)(unaudited)</i>	<b>2008</b>	<b>2007</b>	<b>2008</b>	<b>2007</b>
Interest on long-term debt	<b>9.8</b>	9.0	<b>28.5</b>	27.1
Interest on short-term debt	<b>0.2</b>	-	<b>0.5</b>	4.9
Interest on capital lease obligations	-	1.4	-	4.5
Dividend income from Class B preferred share interests in PERH	<b>(0.5)</b>	(0.4)	<b>(1.4)</b>	(1.2)
Realized losses on interest rate contracts	-	8.1	-	2.6
Fair value changes on interest rate contracts	-	(1.2)	-	1.0
Other	<b>(0.3)</b>	(0.2)	<b>(0.2)</b>	0.8
	<b>9.2</b>	16.7	<b>27.4</b>	39.7

Financial charges and other expenses, excluding realized gains and fair value changes on interest rate contracts, were \$9.2 million and \$27.4 million for the three and nine months ended September 30, 2008 compared to \$9.8 million and \$36.1 million for same periods in 2007. The decreases were primarily due to the repayment of short-term and long-term debt with the proceeds from Partnership unit and preferred share issues in the second quarter of 2007 and the buy-out of capital lease obligations with lower cost long-term debt in the third quarter of 2007. In addition, the Partnership recorded realized losses on and changes in the fair value of interest rate contracts for the three and nine months ended September 30, 2007.

### INCOME TAX EXPENSE

Income tax recovery was \$21.9 million and \$4.2 million for the three and nine months ended September 30, 2008 compared to income tax expense of \$0.8 million and \$75.4 million for the same periods in 2007. A change in tax law in the second quarter of 2007, which will result in the

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Partnership’s Canadian operations becoming taxable in 2011, resulted in the recording of a future income tax expense of \$75.5 million. The income tax recovery recorded for the three and nine months ended September 30, 2008 primarily relate to the future income taxes resulting from changes in the temporary differences expected to reverse after 2010 that will be subject to the SIFT taxes. Income taxes also relate to the income taxes of the Partnership’s US subsidiaries and withholding taxes on distributions from the US subsidiaries.

Withholding taxes on payments between US and Canadian subsidiaries, excluding dividends, are expected to be eliminated by 2010 on a phased in basis going from the current 10% rate to 7% for payments made in 2008 and 4% in 2009. The elimination of this withholding tax is expected to reduce cash taxes by \$2 million per year when fully implemented in 2010 from current levels.

### PREFERRED SHARE DIVIDENDS OF A SUBSIDIARY COMPANY

A subsidiary of the Partnership issued preferred shares in the second quarter of 2007, which pay dividends at a rate of 4.85% per annum. For the three and nine months ended September 30, 2008, dividends of \$1.5 million and \$4.5 million were paid to shareholders and net income tax expenses of \$0.1 million and \$0.4 million were recorded. Part VI.1 tax is paid at a rate of 40% of the dividends and a deduction from Part I tax is available for payment of Part VI.1 tax. The subsidiary expects to realize the benefit of the deduction in 2011.

### GAINS (LOSSES) ON DERIVATIVE INSTRUMENTS

Three months ended September 30 <i>(millions of dollars)(unaudited)</i>	Income Statement Category	Amounts Recorded In Income Statement		Amounts Realized	
		2008	2007	2008	2007
Foreign exchange contracts <sup>(1)</sup>	Revenues	(14.6)	14.5	-	-
Natural gas contracts	Cost of fuel	(160.5)	(52.7)	-	-
Foreign exchange contracts	Foreign exchange (gains) losses	0.1	-	0.1	-
Interest rate contracts	Financial charges and other, net	-	(6.9)	-	(8.1)
		(175.0)	(45.1)	0.1	(8.1)

Nine months ended September 30 <i>(millions of dollars)(unaudited)</i>	Income Statement Category	Amounts Recorded In Income Statement		Amounts Realized	
		2008	2007	2008	2007
Foreign exchange contracts <sup>(1)</sup>	Revenues	(23.9)	37.7	-	-
Natural gas contracts	Cost of fuel	9.8	(68.2)	-	-
Foreign exchange contracts	Foreign exchange (gains) losses	(0.1)	(20.0)	(0.1)	(15.3)
Interest rate contracts	Financial charges and other, net	-	(3.6)	-	(2.6)
		(14.2)	(54.1)	(0.1)	(17.9)

<sup>(1)</sup> Amounts realized on foreign exchange contracts for operating cash flow are included in plant revenue.

Discussion of changes in fair value amounts is included in the respective income statement categories. The amounts realized are included in cash provided by operating activities.

## LIQUIDITY AND CAPITAL RESOURCES

### Cash distributions

Cash distributions of \$0.63 per unit were declared for the third quarter of 2008, consistent with the same period in 2007. When cash provided by operating activities plus the dividend from PERH exceeds cash distributions and maintenance capital expenditures, the Partnership utilizes the difference to stabilize future quarterly cash distributions, to finance future capital expenditures and to make debt repayments. When cash provided by operating activities plus dividends from PERH are less than cash distributions and maintenance capital expenditures, the Partnership utilizes available cash balances and short-term financing to cover the shortfall.

<i>(millions of dollars)(unaudited)</i>	Three months ended		Nine months ended	
	September 30		September 30	
	2008	2007	2008	2007
Cash distributions	<b>34.0</b>	33.9	<b>101.9</b>	99.3
Cash provided by operating activities	<b>21.5</b>	26.5	<b>104.8</b>	95.0
Net (loss) income	<b>(153.0)</b>	(15.9)	<b>5.3</b>	(14.5)
Dividend from PERH	<b>0.8</b>	0.5	<b>2.4</b>	2.8
Additions to property, plant and equipment	<b>6.4</b>	2.6	<b>21.9</b>	7.9
Excess (shortfall) of cash provided by operating activities over cash distributions	<b>(12.5)</b>	(7.4)	<b>2.9</b>	(4.3)
Shortfall of net income over cash distributions	<b>(187.0)</b>	(49.8)	<b>(96.6)</b>	(113.8)

Cash distributions exceeded cash provided by operating activities by \$12.5 million for the three months ended September 30, 2008 and cash provided by operating activities exceeded cash distributions by \$2.9 million for the nine months ended September 30, 2008. The cash shortfall in the third quarter of 2008 was the result of an increase in operating working capital. While the Partnership anticipates seasonal fluctuations in its working capital, it does not expect a significant increase in working capital requirements over the long-term for existing operations. The shortfall between cash distributions and cash provided by operating activities has been funded with a combination of cash on hand and draws on credit facilities, which were repaid subsequent to September 30, 2008. The Partnership also incurred capital expenditures of \$6.4 million and \$21.9 million during the three and nine months ended September 30, 2008.

Net income is not necessarily comparable to cash distributions as net income includes items such as unrealized gains and losses on translation of US dollar-denominated debt and changes in the fair value of derivative instruments. Aside from these items, management expects that distributions will exceed net income. Accordingly, a portion of the distributions represent a return of capital. To date, and subject to ensuring adequate liquidity, the Partnership has chosen to make distributions that include a return of capital. The Partnership believes that major investments of capital to maintain or increase productive capacity are often most effectively made by obtaining new capital in the external markets at the time of the required investment and not necessarily using retained cash.

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To the extent there is a shortfall between the Partnership's cash provided by operating activities and cash distributions and capital expenditures, the Partnership has available to it three revolving credit facilities, each of \$100.0 million. Two of the revolving credit facilities expire in June and September 2010 respectively and the third revolving credit facility expires in October 2011. Alternatively, in the case of major investments of capital the Partnership may obtain new capital from external markets at the time of the required investment.

The third quarter 2008 cash distribution of \$0.63 per unit will be paid on October 30, 2008 to unitholders of record on September 30, 2008.

### Capital expenditures

Capital expenditures for the three and nine months ended September 30, 2008 totalled \$6.4 million, and \$21.9 million respectively, compared with \$2.6 million and \$7.9 million for the same periods in 2007. Capital spending for the three and nine months ended September 30, 2008 included \$1.9 million and \$3.6 million invested in the enhancement of the Southport and Roxboro coal plants. Total maintenance capital spending for 2008 is expected to be in the \$23 million to \$25 million range, in line with earlier expectations. In addition, the Partnership plans to invest up to US\$80 million in 2008 and 2009 for the enhancement of the Southport and Roxboro coal plants to reduce environmental emissions and improve the economic performance. The spending will be financed using available credit facilities, with permanent long-term financing to be arranged after the completion of the project, depending on the requirements of the Partnership. The expected contribution for the project remains in line with past guidance of approximately 10 cents per unit.

### Financial market liquidity

Turmoil in the Canadian and US financial markets may adversely impact the Partnership’s access to capital. The Partnership has a good liquidity position with revolving credit facilities of \$300 million with Canadian tier 1 banks and no significant near term debt maturities. Principal repayments on the Partnership’s long-term debt facilities are as follows:

<b>Year</b>	<b>Principal repayment</b> <i>(millions of dollars)</i>
2009	1.3
2010	1.4
2014	202.2
2017	159.6
2019	79.8
2036	210.0

The Partnership expects to borrow US\$73 million on the credit facility maturing in June 2010 to finance the Morris acquisition. The \$17.0 million borrowed on the credit facilities at September 30, 2008 was repaid in October.

The Partnership continues to monitor changes in counterparty credit quality. Counterparties to the Partnership’s PPAs are primarily investment grade, with over 80% of operating margin from counterparties with a credit rating of A- or higher by Standard and Poors and include

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government agencies and utilities. The balance of the PPAs are with enterprises with investment grade credit ratings of at least BBB-. The A credit rating is the third highest rating and the BBB credit rating is the fourth highest rating out of 10 rating categories. The minus sign shows the relative standing within the major rating categories. The exposure to counterparty credit risk will increase on the acquisition of Morris as the Equistar has a non-investment grade credit rating. The more significant counterparty risk is with waste wood suppliers given current market conditions, both in terms of slowing demand in the housing industry and its impact on the forestry industry in Canada as well as potential constraints waste wood suppliers may face in raising new capital. We have been actively seeking new sources of supply.

The Partnership has to date identified very little direct exposure to international banking and insurance company failures. As part of its Morris acquisition, there are certain natural gas hedges with a subsidiary of the Fortis Bank SA/NV (Fortis) that have a current fair value of approximately \$3 million. The Government of Belgium recently announced that it would be providing financial support to Fortis. The Partnership is not aware of any other direct exposure to financially distressed international bank and insurance companies.

Turmoil in the Canadian and US financial markets, should it continue, may adversely affect the Partnership’s ability to arrange permanent long-term financing for the Morris acquisition after it closes, for significant capital expenditures, such as enhancement expenditures at Roxboro and Southport and potentially to refinance indebtedness under the credit facilities outstanding at their maturity dates.

The market turmoil has resulted in a decline in the market price of the Partnership units and equity markets in general, which will make financing acquisitions more difficult and may negatively impact the PERH sales process.

### **FOREIGN EXCHANGE RISK MANAGEMENT**

The Partnership manages the foreign exchange risk of its anticipated US dollar-denominated cash flows from its US plants through the use of forward foreign exchange contracts for periods up to seven years. As at September 30, 2008, \$369.9 million (US\$341.0 million) or approximately 82% of expected future cash flows were economically hedged for 2008 to 2014 at a weighted average exchange rate of \$1.08 to US \$1.00.

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### TRANSACTIONS WITH RELATED PARTIES

<i>(millions of dollars)(unaudited)</i>	Three months ended		Nine months ended	
	September 30	September 30	September 30	September 30
	2008	2007	2008	2007
<b>Transactions with the Manager</b>				
Cost of fuel - Castleton gas demand charge	0.6	0.5	1.6	1.6
Operating and maintenance expense	12.9	12.2	39.1	38.1
<b>Management and administration</b>				
Base fee	0.3	0.3	1.0	1.0
Incentive fee	0.5	0.6	1.7	1.7
Enhancement fee	0.9	0.1	2.3	0.7
Administration fee	0.2	0.2	0.7	0.6
	1.9	1.2	5.7	4.0
<b>Transactions with PERC</b>				
<b>Revenue</b>				
Base management fees	0.9	0.8	2.6	2.6

In operating the Partnership’s 20 power plants, the Partnership and EPCOR engage in a number of related party transactions which are in the normal course of business. These transactions are based on contracts and many of the fees are escalated by inflation. The table above summarizes the amounts included in the calculation of net income for the three and nine months ended September 30, 2008 and 2007.

The Partnership makes quarterly cash distributions to EPCOR in the amount proportionate to its ownership interest. At September 30, 2008, EPCOR owned 30.6% of the Partnership’s units (September 30, 2007 – 30.6%).

### CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

The Partnership has committed up to US\$80 million for the enhancement of the Southport and Roxboro facilities, to be spent over 2008 and 2009. There were no other material changes to the Partnership’s purchase obligations, commitments or contingencies during the third quarter, including payments for the next five years and thereafter other than the proposed acquisition of Morris (see Significant Events – Morris Acquisition). For further information on these obligations, refer to the Partnership’s 2007 Annual MD&A.

### CRITICAL ACCOUNTING ESTIMATES

Since a determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Partnership’s consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment. The Partnership’s critical accounting estimates include tax provision calculations as a result of the Partnership becoming taxable in 2011, depreciation and amortization expense, asset retirement

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obligations and fair value estimates. For further information on the Partnership’s critical accounting estimates, refer to the Partnership’s 2007 Annual MD&A.

The fair value of non-financial derivatives reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value amounts reflect management’s best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of futures prices and foreign exchange rates, time value and volatility. It is possible that the assumptions used in establishing fair value amounts will differ from actual prices and the impact of such variations could be material.

### **INTERNAL CONTROL OVER FINANCIAL REPORTING**

There were no changes made to the Partnership’s internal controls over financial reporting during the interim period ended September 30, 2008 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

### **BUSINESS RISKS**

The Partnership’s business and operational risks remain substantially unchanged since December 31, 2007, other than those discussed under Liquidity and Capital Resources - Financial Market Liquidity. Recent developments on risk are described below. For further information on business risks, refer to the Partnership’s December 31, 2007 MD&A.

#### **Proposed emissions regulations**

On March 10, 2008, the Canadian Environment Minister released further information on the proposed new regulatory framework to reduce greenhouse gas emissions and air pollution in Canada that was originally announced on April 26, 2007. These changes do not materially alter the Partnership’s expectations for the costs of compliance estimated in its December 31, 2007 MD&A. The Partnership estimates the cost to meet the proposed regulations for carbon dioxide emissions to be approximately \$1 million annually starting in 2010 escalating to \$2 million annually by 2020. The Partnership estimates the costs to comply with anticipated legislation for nitrogen oxide emissions to be \$3 million to \$4 million in one-time capital costs.

On July 11, 2008, the U.S. Washington District Court vacated the Clean Air Interstate Rule (CAIR) in its entirety. CAIR regulations were to take effect the beginning of 2009, setting required reductions in nitrogen oxide (NOx) and sulphur dioxide (SO<sub>2</sub>) emissions which would have impacted the Southport and Roxboro facilities. The Partnership had planned to address the CAIR regulations through capital upgrades to its emissions control equipment at these facilities. The Partnership intends to continue with these capital improvements despite the CAIR decision because:

- The capital improvements include changes to the fuel handling system and boiler modifications that allow for increased use of wood waste and tire-derived fuels which improve the economics for Southport and Roxboro;
- The new emission control equipment substantially reduces SO<sub>2</sub> and NOx emissions which is beneficial for the environment; and
- The Partnership expects that the CAIR regulation will be replaced at some point in the future with similar legislation to limit SO<sub>2</sub> and NOx emissions.

**PERH distributions**

An amendment to the Harbor Coal agreement was executed on April 3, 2008, which is expected to provide more stable and predictable cash flow. As a result, increased interest costs to PERH and the possibility of cash sweeps under the senior lending agreement were eliminated.

On September 24, 2008 the Partnership and PERC announced they are undertaking a sale process that could lead to the sale of PERC and/or PERH.

**FUTURE ACCOUNTING STANDARDS**

**International financial reporting standards**

In February 2008, the CICA confirmed that Canadian reporting issuers will be required to report under International Financial Reporting Standards (IFRS) effective January 1, 2011, including comparative figures for the prior year.

In January 2008, a core team was established to develop a plan which would result in the Partnership’s first interim report for 2011 being in compliance with IFRS.

The diagnostic phase was completed in April 2008. For each international standard, differences from Canadian GAAP were identified and an initial assessment was made of the impact of the required changes for the purpose of prioritizing and assigning resources. In making the assessment, the potential magnitude of the financial statement adjustment, the availability of policy choices, the impacts on systems and the impacts on internal controls were all considered.

The information obtained from the diagnostic phase was used to develop a detailed plan for convergence and implementation. The convergence and implementation work has five key sections: Financial Statement Adjustments, Financial Statements, Systems Updates, Policies and Internal Controls, and Training.

*Financial statement adjustments*

Based on the results of the diagnostic phase, the standards most likely to have a significant impact on the Partnership are property, plant and equipment, financial instruments, interests in joint ventures, foreign currency translation, provisions, contingent liabilities and contingent assets, business combinations, impairment of assets, leases, revenue and income taxes. Certain standards which may have a significant impact and are expected to change before January 1, 2011, such as Joint Ventures, will be addressed later in the plan depending on the expected timing of the revised standard.

For each standard, the quantitative impacts to the financial statements, system requirements, accounting policy decisions, and changes to internal controls and business policies will be determined. The initial accounting policy decisions will be brought forward to the Audit Committee for their review as each standard is addressed; however, final accounting policy decisions for all standards which have been reviewed by the Audit Committee at the end of 2009 will be made in the fourth quarter of 2009, as they should not be determined in isolation of other policy decisions. Policy decisions for standards that are amended in 2010 will be made as part of our analysis of the standards in 2010.

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### *Financial statements*

There are also a number of standards which relate to financial statement presentation. Commencing in the fourth quarter of 2008, sample financial statements reflecting revised presentation and disclosure requirements, will be developed and brought forward to the Audit Committee for feedback. Accordingly, the development of the financial statement presentation will evolve throughout the project.

### *Systems updates*

The diagnostic phase identified two key accounting system requirements. The system must be able to capture 2010 financial information under both existing GAAP and IFRS to allow comparative reporting in 2011. It must also be able to accommodate the possible requirements for changes to foreign currency translation methods, depending on how certain foreign entities are classified under IFRS. A detailed system strategy is being developed to address these issues.

### *Policies and internal controls*

In the determination of the financial statement adjustments, requirements for changes to Partnership policies and internal controls will be identified and documented. As there may be factors other than IFRS impacting policies and internal controls, the formal documentation and approval of revised policies and internal controls will not occur until the third quarter of 2010.

The impact of IFRS on certain agreements, such as debt agreements, has also been included in the plan. Strategies to address these issues are being developed and will be completed by the second quarter of 2009.

### *Training*

The Partnership recognizes that training at all levels is essential to a successful conversion and integration. Accounting staff have attended an initial IFRS training session, and periodic sessions will occur throughout the conversion process. The Board of Directors and Audit Committee have attended a training session, and the Audit Committee receives regular updates on the conversion project. Training will occur throughout the project.

### **Goodwill and intangible assets**

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding IFRS provisions. The provisions relating to goodwill are unchanged from those of the replaced Section 3062 – Goodwill and Other Intangible Assets. These amendments are effective January 1, 2009. The Partnership does not expect the adoption of the new standard to result in a material transition adjustment to its financial statements.

## **OUTLOOK**

The Partnership’s longer term outlook remains substantially unchanged since December 31, 2007. For further information on our outlook, refer to the Partnership’s December 31, 2007 MD&A. An update to those items previously disclosed includes:

- The acquisition of Morris is expected to be completed in the fourth quarter of 2008 and is expected to be modestly accretive to cash flow. The Partnership is evaluating alternatives to improve that value to the facility by leveraging the Partnership’s operating expertise and capitalizing on growth opportunities within the geographical area;
- Natural gas transportation costs for the Ontario plants are expected to increase by \$2 million in 2008 from 2007 due to increases in natural gas transportation tariffs. There may be further tariff increases as a result of continued decreases in natural gas flow on the TransCanada Canadian Mainline and relatively high natural gas prices;
- PERH distributions should be more stable in the future due to the amendment to the Harbor Coal agreement, which is expected to provide more predictable cash flow;
- Lower pipeline volumes resulted in lower waste heat revenues and higher waste heat optimization costs at the Ontario plants in the first nine months of 2008 compared to the same period in 2007. Throughput on the TransCanada Canadian Mainline is expected to continue to be lower for the remainder of 2008 compared to 2007 with recoveries in volumes not expected prior to 2012. Management is actively working with TransCanada to address opportunities to mitigate the financial impact of lower waste heat availability;
- Expected increase in Curtis Palmer PPA pricing of 18% in December 2008 subject to meeting cumulative production thresholds;
- Damage to the Oxnard turbine is expected to cost \$3 million to \$4 million to repair and may be partially covered by insurance and/or warranty from the company who recently performed maintenance on the turbine;
- Withholding taxes on payments between US and Canadian subsidiaries, excluding dividends, are expected to be eliminated by 2010, resulting in a reduction in cash taxes of \$2 million per year;
- A three year financial natural gas swap contract that covers most of the anticipated supply requirements for Greeley is expected to result in positive operating margin from the facility based on the PPA terms; and
- Capital and credit market turmoil is not expected to adversely impact the Partnership in the near term as the Partnership has a good liquidity position with available credit facilities of \$300 million and no significant near term debt maturities.

Based on the Partnership’s 2008 operating and capital plan and taking into consideration the points noted above, cash distributions are expected to remain at the current annual level of \$2.52 per unit in 2008, subject to any material changes that may occur during the year.

## **FORWARD-LOOKING INFORMATION**

Certain information in this MD&A is forward-looking and related to anticipated financial performance, events and strategies. When used in this context, words such as “will”, “anticipate”, “believe”, “plan”, “intend”, “target” and “expect” or similar words suggest future outcomes. By their nature, such statements are subject to significant risks, assumptions and uncertainties, which could cause the Partnership’s actual results and experience to be materially different than the anticipated results. In particular, forward-looking information and statements

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include: (i) expected capital spending of \$23 million to \$25 million in 2008, (ii) planned capital upgrades at Southport and Roxboro of US\$80 million which are expected to result in a contribution of \$0.10 per unit, (iii) the acquisition of Morris is expected to close in the fourth quarter of 2008, will be financed with credit facilities, will be modestly accretive to cash flow and the Partnership will evaluate opportunities to increase the value of Morris, (iv) Curtis Palmer will reach the next pricing block in its PPA in December 2008, (v) expectations for the costs to comply with anticipated emissions regulation, (vi) expectations for throughput on the TransCanada Canadian Mainline and related waste heat availability and optimization costs at the Ontario facilities, (vii) expectations for lower operating margin at the Castleton facility after the PPA expired in June 2008, (viii) expectations regarding the time at which the Partnership will be taxable, (ix) distributions will be maintained at \$2.52 per unit in 2008, and (x) expectation regarding the impact on the Partnership of the capital and credit market turmoil.

These statements are based on certain assumptions and analysis made by the Partnership in light of its experience and perception of historical trends, current conditions and expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements include: (i) the Partnership's operations, financial position and available credit facilities, (ii) the Partnership's assessment of commodity, currency and power markets, (iii) the markets and regulatory environment in which the Partnership's facilities operate, (iv) the state of capital markets, (v) management's analysis of applicable tax legislation, (vi) the assumption that the currently applicable and proposed tax laws will not change and will be implemented, (vii) the assumption that currently proposed emissions regulations will be implemented as proposed, (viii) the assumption that counterparties to fuel supply and power purchase agreements will continue to perform their obligations under the agreements, (ix) that current third party expectations regarding throughput on the TransCanada Canadian Mainline will continue, (x) the level of plant availability and dispatch, (xi) the performance of contractors and suppliers, (xii) the renewal and terms of PPAs, (xiii) management's analysis and due diligence of the Morris facility, including the related purchase and supply agreements, (xiv) the ability of the Partnership to successfully integrate and realize the benefits of its acquisitions, (xv) the ability of the Partnership to implement its strategic initiatives and whether such initiatives will yield the expected benefits, and (xvi) expected water flows.

Whether actual results, performance or achievements will conform to the Partnership's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results to differ materially from the Partnership's expectations. Such risks and uncertainties include, but are not limited to risks relating to (i) the operation of the Partnership's facilities, (ii) plant availability and performance, (iii) the availability and price of energy commodities including natural gas and wood waste, (iv) the performance of counterparties in meeting their obligations under PPAs, (v) competitive factors in the power industry, (vi) economic conditions, including in the markets served by the Partnership' facilities, (vii) changing demand for natural gas in northern Ontario and areas further to the east and levels of natural gas supply in western Canada available for shipping on the TransCanada Pipeline Mainline, (viii) on-going compliance by the Partnership with its current debt covenants, (ix) developments within the North American capital markets, (x) the availability and cost of permanent long term financing in respect of acquisitions and investments, (xi) unanticipated maintenance and other expenditures, (xii) the Partnership's ability to successfully realize the benefits of acquisitions and investments, (xiii) changes in regulatory and government decisions including changes to emission regulations, (xiv) changes in existing and proposed tax and other legislation in Canada and the United States and including changes in the Canada-US tax treaty,

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(xv) the tax attributes of and implications of any acquisitions, and (xvi) the availability and cost of equipment.

This MD&A includes the following updates to previously issued forward-looking statements: (i) The Frederickson milestone payment was made in the second quarter, earlier than previous expectations of the third quarter due to higher running hours at Frederickson than expected, (ii) wood supply at Calstock has dried out in line with previously reported expectations, and (iii) the purchase price for Morris of US\$73 million is lower than the previously disclosed amount of US\$77 million as preliminary closing adjustments have been determined.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Except as required by law, the Partnership disclaims any intention and assumes no obligation to update any forward-looking statement.

### SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

<i>(unaudited)</i> <i>(millions of dollars except per unit amounts)</i>	2008				2007			2006
	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	138.0	147.3	121.4	117.6	153.4	165.3	142.9	105.3
Operating margin <sup>(1)</sup>	(118.8)	156.8	108.6	83.1	20.6	16.2	103.9	43.3
Net (loss) income	(153.0)	104.9	53.4	45.3	(15.9)	(68.0)	69.4	(12.9)
Cash provided by operating activities	21.5	40.4	42.9	38.0	26.5	7.8	60.7	34.4
Capital expenditures	6.4	11.7	3.8	4.6	2.6	4.2	1.1	9.0
Cash distributions	34.0	33.9	34.0	34.0	33.9	34.0	31.4	31.4
<b>Per unit statistics</b>								
Net (loss) income	\$ (2.84)	\$ 1.95	\$ 0.99	\$ 0.84	\$ (0.29)	\$ (1.33)	\$ 1.39	\$ (0.26)
Cash provided by operating activities <sup>(1)</sup>	\$ 0.40	\$ 0.75	\$ 0.80	\$ 0.71	\$ 0.49	\$ 0.15	\$ 1.22	\$ 0.69
Cash distributions	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63

<sup>(1)</sup>The selected quarterly consolidated financial data has been prepared in accordance with GAAP except for operating margin and cash provided by operating activities per unit. See Non-GAAP Measures.

### Factors impacting quarterly financial results

The Partnership’s Selected Quarterly Financial Data, which has been prepared in accordance with GAAP, except as noted, is set out above. Quarterly revenues, net income and cash provided by operating activities are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in US dollar exchange rates relative to the Canadian dollar, attainment of firm energy requirements, natural gas prices, waste heat availability and planned and unplanned plant outages, as well as items outside of the normal course of operations. Quarterly net income is also affected by unrealized foreign exchange gains and losses primarily on the Partnership’s US dollar-denominated long-term debt and fair value changes in foreign exchange contracts and natural gas supply contracts.

The Partnership’s cash flow tends to be relatively stable over the year with seasonal fluctuations at the individual facilities. The Naval facilities earn approximately 75% of their capacity revenue during the summer peak demand months and all the California plants can earn performance bonuses during these months. Under the power sales contracts for the Ontario plants, the Partnership receives higher per megawatt hour prices in the winter months (October to March) and lower prices in the summer months (April to September). The lower summer prices reduce the threshold for economic curtailments thereby increasing the profitability of enhancements, natural gas prices being equal. Contributions from Williams Lake are usually lower in the fourth quarter once the annual firm energy requirements are fulfilled and the plant is only producing

## **EPCOR Power L.P. – Management’s discussion and analysis – 2008 Q3**

lower-priced excess energy. Revenues from the hydroelectric facilities are generally higher in the spring months due to seasonally higher water flows.

Significant items which impacted the last eight quarters’ net income were as follows:

In the third quarter of 2007, the Partnership recorded a \$13.0 million asset impairment charge in respect of certain management contracts.

In the second quarter of 2007, a future income tax expense of \$75.5 million was recognized due to a change in tax law which will result in the Partnership’s Canadian operations becoming taxable in 2011.

In the second quarter of 2007, the Partnership reached a settlement with one of its natural gas suppliers and recorded additional fuel costs of \$2.8 million for consumption in the first two quarters of 2007. At the same time, the Partnership reversed accruals of \$3.1 million related to periods ending before December 31, 2006. As a result of the settlement, fuel costs for the last two quarters of 2007 were approximately \$2.6 million higher than in 2006. Settlement with the second natural gas supplier was reached in the first quarter of 2008 on terms anticipated in the second quarter of 2007. In the third quarter of 2008 the Partnership recorded a \$3.4 million reduction in natural gas costs as we updated our estimate of the cost for natural gas supplied under contract.

In the first quarter of 2007, the Partnership began reporting natural gas supply contracts for the Ontario plants at fair value. The Partnership recorded gains on the change in the fair value of the natural gas supply contracts in the first and fourth quarters of 2007 and the first and second quarters of 2008 and losses in the second and third quarters of 2007 and the third quarter of 2008.

Unrealized foreign exchange gains on US dollar-denominated debt were recorded in all four quarters of 2007 and the second quarter of 2008. Losses were recorded in the fourth quarter of 2006 and the first and third quarters of 2008. The gains and losses are due to fluctuations in the US dollar relative to the Canadian dollar.

Unrealized fair value changes on foreign exchange contracts resulted in gains in the first three quarters of 2007 and the second quarter of 2008. Losses were recorded in the fourth quarter of 2006, in the fourth quarter of 2007 and in the first and third quarters of 2008.

The fourth quarter of 2006 and the first quarters of 2007 and 2008 had unseasonably high water flows at Curtis Palmer, while the fourth quarter of 2007 had unseasonably low water flows.

In the fourth quarter of 2006, the Partnership acquired Primary Energy Ventures LLC (now EPCOR Ventures USA LLC).

**QUARTERLY UNIT TRADING INFORMATION**

The Partnership units trade on the Toronto Stock Exchange under the symbol EP.UN.

<b>For the three months ended</b> <i>(unaudited)</i>	<b>Sep. 30 2008</b>	<b>Jun. 30 2008</b>	<b>Mar. 31 2008</b>	<b>Dec. 31 2007</b>	<b>Sep. 30 2007</b>
<b>Unit price</b>					
High	\$23.50	\$24.70	\$23.78	\$25.29	\$27.90
Low	\$19.83	\$21.52	\$19.65	\$20.11	\$22.10
Close	\$20.32	\$22.41	\$21.90	\$23.37	\$24.64
<b>Volume traded (millions)</b>	3.6	4.5	4.8	6.3	4.5

As at October 28, 2008, the Partnership had 53.9 million units outstanding. The weighted average number of units outstanding for the three and nine months ended September 30, 2008 was 53.9 million which is higher than the same period in 2007 due to the issue of 4.0 million units in the second quarter of 2007 related to an acquisition completed in 2006.

**ADDITIONAL INFORMATION**

Additional information relating to EPCOR Power L.P. including the Partnership’s Annual Information Form and continuous disclosure documents are available on SEDAR at [www.sedar.com](http://www.sedar.com).

**EPCOR Power L.P.**  
**CONSOLIDATED STATEMENTS OF INCOME AND LOSS**

	Three months ended September 30		Nine months ended September 30	
<i>(unaudited)</i>	<b>2008</b>	2007	<b>2008</b>	2007
<i>(In millions of dollars except units and per unit amounts)</i>				
<b>Revenues</b>	<b>\$ 138.0</b>	\$ 153.4	<b>\$ 406.7</b>	\$ 461.6
<b>Cost of fuel</b>	<b>228.7</b>	110.9	<b>185.0</b>	249.7
<b>Operating and maintenance expense</b>	<b>21.2</b>	14.9	<b>52.3</b>	46.1
<b>Other plant operating expenses</b>	<b>6.9</b>	7.0	<b>22.8</b>	25.1
	<b>(118.8)</b>	20.6	<b>146.6</b>	140.7
<b>Other costs (income)</b>				
Depreciation and amortization	<b>23.1</b>	23.0	<b>70.0</b>	68.8
Management and administration	<b>4.7</b>	3.8	<b>13.2</b>	9.7
Foreign exchange losses (gains)	<b>15.8</b>	(24.1)	<b>26.2</b>	(56.3)
Equity losses in PERH	<b>1.7</b>	1.7	<b>3.8</b>	2.7
Financial charges and other, net (Note 3)	<b>9.2</b>	16.7	<b>27.4</b>	39.7
Asset impairment charge	<b>-</b>	13.0	<b>-</b>	13.0
	<b>54.5</b>	34.1	<b>140.6</b>	77.6
<b>Net (loss) income before income tax and preferred share dividends</b>	<b>(173.3)</b>	(13.5)	<b>6.0</b>	63.1
<b>Income tax (recovery) expense</b>	<b>(21.9)</b>	0.8	<b>(4.2)</b>	75.4
<b>Net (loss) income before preferred share dividends</b>	<b>(151.4)</b>	(14.3)	<b>10.2</b>	(12.3)
Preferred share dividends of a subsidiary company	<b>1.6</b>	1.6	<b>4.9</b>	2.2
<b>Net (loss) income</b>	<b>\$ (153.0)</b>	\$ (15.9)	<b>\$ 5.3</b>	\$ (14.5)
<b>Net (loss) income per unit</b>	<b>(\$2.84)</b>	(\$0.29)	<b>\$ 0.10</b>	(\$0.28)
<b>Weighted average units outstanding (millions)</b>	<b>53.9</b>	53.9	<b>53.9</b>	51.7

See accompanying notes to the consolidated financial statements.

**EPCOR Power L.P.**  
**CONSOLIDATED STATEMENTS OF CASH FLOW**

<i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2008	2007	2008	2007
<i>(In millions of dollars)</i>				
<b>Operating activities</b>				
Net (loss) income	\$ (153.0)	\$ (15.9)	\$ 5.3	\$ (14.5)
Items not affecting cash:				
Depreciation and amortization	23.1	23.0	70.0	68.8
Asset impairment charge	-	13.0	-	13.0
Future income tax	(22.9)	(0.7)	(7.8)	70.8
Fair value changes on derivative instruments	175.1	37.1	14.1	36.3
Unrealized foreign exchange losses (gains)	15.9	(24.1)	26.1	(76.3)
Other	2.8	2.3	5.1	4.2
	41.0	34.7	112.8	102.3
Change in non-cash operating working capital	(19.5)	(8.2)	(8.0)	(7.3)
Cash provided by operating activities	21.5	26.5	104.8	95.0
<b>Investing activities</b>				
Additions to property, plant and equipment	(6.4)	(2.6)	(21.9)	(7.9)
Change in non-cash working capital	(5.6)	(2.8)	0.1	(1.8)
Dividends from PERH	0.8	0.5	2.4	2.8
Cash used in investing activities	(11.2)	(4.9)	(19.4)	(6.9)
<b>Financing activities</b>				
Distributions paid	(33.9)	(33.9)	(101.8)	(96.7)
Proceeds from preferred share offering	-	-	-	125.0
Proceeds from unit offering	-	-	-	105.0
Proceeds from long-term debt	-	240.0	-	240.0
Proceeds from credit facility	17.0	11.2	17.0	11.2
Short-term debt repaid	-	-	-	(200.5)
Capital lease obligation repaid	-	(71.7)	-	(74.4)
Long-term debt repaid	(0.6)	(155.6)	(1.1)	(185.9)
Issue costs	-	(0.8)	-	(8.7)
Cash used in financing activities	(17.5)	(10.8)	(85.9)	(85.0)
Foreign exchange gains (losses) on cash held in a foreign currency	0.1	(2.9)	0.8	(3.9)
<b>(Decrease) increase in cash and cash equivalents</b>	<b>(7.1)</b>	<b>7.9</b>	<b>0.3</b>	<b>(0.8)</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>27.5</b>	<b>23.3</b>	<b>20.1</b>	<b>32.0</b>
<b>Cash and cash equivalents, end of period</b>	<b>\$ 20.4</b>	<b>\$ 31.2</b>	<b>\$ 20.4</b>	<b>\$ 31.2</b>
<b>Supplementary cash flow information</b>				
Income taxes paid net of income taxes recovered	\$ 2.3	\$ 1.1	\$ 6.8	\$ 3.6
Interest paid net of interest received	\$ 13.7	\$ 10.4	\$ 31.2	\$ 39.8

See accompanying notes to the consolidated financial statements.

**EPCOR Power L.P.**  
**CONSOLIDATED BALANCE SHEETS**

<i>(unaudited)</i>	September 30, 2008	December 31, 2007
(In millions of dollars)		
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 20.4	\$ 20.1
Accounts receivable	67.5	75.1
Inventories (Note 4)	14.1	13.6
Prepays and other	8.0	4.7
Future income taxes	1.9	1.9
Derivative instruments assets (Note 5)	31.2	35.0
	<b>143.1</b>	<b>150.4</b>
<b>Property, plant and equipment</b>	<b>1,028.9</b>	<b>1,052.9</b>
<b>Power purchase arrangements</b>	<b>428.0</b>	<b>453.2</b>
<b>Long-term investments</b>	<b>43.5</b>	<b>49.6</b>
<b>Goodwill</b>	<b>50.9</b>	<b>50.9</b>
<b>Future income taxes</b>	<b>6.5</b>	<b>-</b>
<b>Derivative instruments assets (Note 5)</b>	<b>53.6</b>	<b>65.2</b>
<b>Other assets</b>	<b>29.9</b>	<b>30.2</b>
	<b>\$ 1,784.4</b>	<b>\$ 1,852.4</b>
<b>LIABILITIES AND PARTNERS' EQUITY</b>		
<b>Current liabilities</b>		
Accounts payable	\$ 44.2	\$ 59.1
Distributions payable	34.0	33.9
Long-term debt due within one year	18.3	1.1
Derivative instruments liabilities (Note 5)	0.6	0.3
	<b>97.1</b>	<b>94.4</b>
<b>Asset retirement obligations</b>	<b>24.3</b>	<b>23.2</b>
<b>Long-term debt</b>	<b>647.9</b>	<b>618.6</b>
<b>Derivative instruments liabilities (Note 5)</b>	<b>4.2</b>	<b>2.9</b>
<b>Contract liabilities</b>	<b>4.0</b>	<b>6.0</b>
<b>Future income taxes</b>	<b>78.7</b>	<b>79.6</b>
<b>Preferred shares issued by a subsidiary company</b>	<b>122.0</b>	<b>122.0</b>
<b>Partners' equity</b>	<b>806.2</b>	<b>905.7</b>
<b>Commitments (Note 9)</b>		
	<b>\$ 1,784.4</b>	<b>\$ 1,852.4</b>

See accompanying notes to the consolidated financial statements.

**EPCOR Power L.P.**  
**CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY**

<i>(unaudited)</i>	<b>Nine months ended September 30</b>	
(In millions of dollars)	<b>2008</b>	<b>2007</b>
<b>Partnership capital</b>		
Balance, beginning of period	\$ 1,197.1	\$ 1,095.5
Issue of partnership units	-	101.6
Balance, end of period	<b>\$ 1,197.1</b>	<b>\$ 1,197.1</b>
<b>Deficit</b>		
Balance, beginning of period:		
As previously reported	\$ (296.5)	\$ (290.1)
Adjustment for changes in accounting policies	-	96.1
As restated	<b>(296.5)</b>	(194.0)
Net income (loss)	<b>5.3</b>	(14.5)
Cash distributions	<b>(101.9)</b>	(99.3)
Balance, end of period	<b>\$ (393.1)</b>	<b>\$ (307.8)</b>
<b>Accumulated other comprehensive income</b>		
Balance, beginning of period	\$ 5.1	\$ -
Cumulative effect of adopting new accounting policies	-	8.6
Other comprehensive loss	<b>(2.9)</b>	(2.6)
Balance, end of period	<b>\$ 2.2</b>	<b>\$ 6.0</b>
Total of deficit and accumulated other comprehensive income	<b>\$ (390.9)</b>	<b>\$ (301.8)</b>
<b>Partners' equity</b>	<b>\$ 806.2</b>	<b>\$ 895.3</b>

See accompanying notes to the consolidated financial statements.

**EPCOR Power L.P.**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND LOSS**

<i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2008	2007	2008	2007
(In millions of dollars)				
<b>Net (loss) income</b>	<b>\$ (153.0)</b>	<b>\$ (15.9)</b>	<b>\$ 5.3</b>	<b>\$ (14.5)</b>
<b>Other comprehensive loss, net of income taxes</b>				
Amortization of deferred gains on derivatives de-designated as cash flow hedges to income <sup>(1)</sup>	<b>(1.0)</b>	(0.8)	<b>(2.9)</b>	(2.6)
<b>Comprehensive (loss) income</b>	<b>\$ (154.0)</b>	<b>\$ (16.7)</b>	<b>\$ 2.4</b>	<b>\$ (17.1)</b>

<sup>(1)</sup> Net of income tax of nil.

*See accompanying notes to the consolidated financial statements.*

**Note 1. Significant accounting policies**

The consolidated financial statements of EPCOR Power L.P. (the Partnership) have been prepared by the management of the General Partner in accordance with Canadian generally accepted accounting principles (GAAP). The accounting policies applied are consistent with those outlined in the Partnership's annual financial statements for the year ended December 31, 2007, except for the changes described in Note 2. These consolidated financial statements reflect all normal recurring adjustments that are, in management's opinion, necessary to present fairly the financial position and results of operations for the respective periods. These consolidated financial statements for the nine months ended September 30, 2008 do not include all disclosures required in the annual financial statements and should be read in conjunction with the annual financial statements included in the Partnership's 2007 Annual Report.

Quarterly revenues, net income and cash provided by operating activities are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in United States (US) dollar exchange rates, fulfillment of firm energy requirements, natural gas prices, waste heat availability and planned and unplanned plant outages, as well as items outside of the normal course of operations. Quarterly net income is also affected by unrealized foreign exchange gains and losses on the Partnership's US dollar-denominated monetary assets and liabilities and fair value changes in derivative instruments. Revenues, net income and cash provided by operating activities from the Partnership's Ontario plants are generally higher in the winter months (October to March) and lower in the summer months (April to September) due to seasonal pricing under the power purchase arrangements (PPAs). Revenues and net income from the Partnership's hydroelectric plants are generally higher in the spring months due to seasonally higher water flows. The California plants normally generate the majority of their operating margin during the summer months when the plants can earn performance bonuses. Additionally, the plants located on Naval bases earn approximately 75% of their capacity revenue during these months.

Since a determination of many assets, liabilities, revenues and expenses is dependent on future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions which have been made with careful judgment. In management's opinion, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Partnership's accounting policies.

**Note 2. Changes in accounting policies**

Commencing January 1, 2008, the Partnership adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants (CICA) for Capital Disclosures, Financial Instruments – Disclosures and Presentation and Inventories. The new accounting standards have been applied prospectively and the comparative financial statements have not been restated.

**Capital disclosures**

The new standards require qualitative information about the Partnership's objectives, policies and processes for managing capital and quantitative data on the Partnership's capital, as discussed in Note 7 – Capital management.

## **Financial instruments – presentation and disclosures**

These new standards establish requirements for the reporting and presentation of quantitative and qualitative information that is intended to provide users of the financial statements with additional insight into the Partnership's risks associated with financial instruments and how these risks are managed. These risks include credit, liquidity and market risks. The additional disclosures required under these new standards have been incorporated into these interim consolidated financial statements and discussed in Note 5 – Financial instruments and Note 6 – Risk management.

## **Inventories**

The new standard requires inventories to be measured at the lower of cost and net realizable value and did not materially impact these consolidated financial statements. The additional disclosures required under the new standard have been incorporated into these interim consolidated financial statements and discussed in Note 4 – Inventories.

## **Future accounting changes**

### *International financial reporting standards*

In February 2008, the CICA confirmed that Canadian reporting issuers will be required to report under International Financial Reporting Standards (IFRS) effective January 1, 2011, including comparative figures for the prior year. In April 2008, the CICA released an exposure draft of the coming standards. A high level IFRS implementation plan has been developed and an assessment of the impact of the accounting standard differences to the financial statements is currently in progress. Based on our analysis to date, the most significant differences for the Partnership are anticipated to be related to property, plant and equipment, joint arrangements, financial instruments and hedges, foreign currency translation, income taxes, impairments, business combinations, emission credits, asset retirement obligations and financial statement disclosure. The Partnership also expects to make changes to certain processes and systems before 2010 to ensure transactions are recorded in accordance with IFRS for comparative reporting purposes on the required implementation date.

### *Goodwill and intangible assets*

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding IFRS provisions. The provisions relating to goodwill are unchanged from those of the replaced Section 3062 – Goodwill and Other Intangible Assets. These amendments are effective January 1, 2009. The Partnership does not expect the adoption of the new standard to result in a material transition adjustment to its financial statements.

**Note 3. Financial charges and other, net**

<i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2008	2007	2008	2007
Interest on long-term debt	\$ 9.8	\$ 9.0	\$ 28.5	\$ 27.1
Interest on short-term debt	0.2	-	0.5	4.9
Interest on capital lease obligations	-	1.4	-	4.5
Dividend income from Class B preferred share interests in PERH	(0.5)	(0.4)	(1.4)	(1.2)
Realized losses on interest rate contracts	-	8.1	-	2.6
Fair value changes on interest rate contracts	-	(1.2)	-	1.0
Other	(0.3)	(0.2)	(0.2)	0.8
	<b>\$ 9.2</b>	<b>\$ 16.7</b>	<b>\$ 27.4</b>	<b>\$ 39.7</b>

**Note 4. Inventories**

Inventories represent general stock and fuel, the majority of which are consumed by the Partnership in provision of its goods and services, and are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs.

The carrying value of the Partnership's inventory is summarized below:

<i>(millions of dollars)</i>	September 30 2008	December 31 2007
General stock	\$ 7.5	\$ 5.6
Fuel	6.6	8.0
	<b>\$ 14.1</b>	<b>\$ 13.6</b>

Inventories expensed in cost of fuel and other plant operating expenses were \$15.0 million and \$34.2 million for the three and nine months ended September 30, 2008 (\$9.6 million and \$28.1 million for the three and nine months ended September 30, 2007).

No write-down of inventory or reversal of a previous write-down was recognized in the three and nine months ended September 30, 2008 or in the same periods of 2007. As at September 30, 2008, no inventories were pledged as security for liabilities (December 31, 2007 – nil).

**Note 5. Financial instruments**

**Fair values and classification of financial assets and liabilities**

The Partnership classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables and accounts payable and distributions payable are classified as other financial liabilities and are measured at amortized cost. The fair values of accounts receivable, accounts payable and distributions payable are not materially different from their carrying values due to their short-term nature. The preferred share interest in Primary Energy Recycling Holdings LLC (PERH) is classified as available for sale and the net investment in lease is classified as loans and receivables. The net investment in lease relates to the Oxnard PPA, which is considered a direct financing lease for accounting purposes.

The classification, carrying values and fair values of the Partnership's other financial instruments are summarized as follows:

	September 30, 2008			Total fair value
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	
Other assets - net investment in lease	\$ 29.4	\$ -	\$ 29.4	\$ 27.8
Long-term debt (including current portion)	-	(666.2)	(666.2)	(610.8)

	December 31, 2007			Total fair value
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	
Other assets - net investment in lease	\$ 28.6	\$ -	\$ 28.6	\$ 27.8
Long-term debt (including current portion)	-	(619.7)	(619.7)	(612.2)

The fair value of the Partnership's long-term debt is based on determining an appropriate yield for the Partnership's debt as at September 30, 2008 and December 31, 2007. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada and US Government bonds that have similar maturities to the Partnership's debt. The estimated credit spread is based on the Partnership's indicative spread as published by independent financial institutions.

The Partnership has used the carrying value of its preferred share interests held in PERH as their fair value as the shares are not quoted in an active market and their fair values therefore cannot be measured reliably. The Partnership has elected to dispose of its PERH shares, and if the transaction takes place, the shares will most likely be sold in a private transaction.

The fair value of the Partnership's net investment in the financing lease is based on the estimated interest rate implicit in a comparable lease arrangement plus an estimated credit spread based on the counterparty risk as at September 30, 2008 and December 31, 2007.

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**Derivative instruments**

Derivative instruments are generally held for the purpose of energy procurement or treasury management. All derivative instruments, including embedded derivatives, are classified as held for trading and are recorded at fair value on the balance sheet as derivative instruments assets and derivative instruments liabilities unless exempted from derivative treatment as a normal purchase, sale or usage. All changes in their fair value are recorded in net income.

The derivative instruments assets and liabilities used for risk management purposes as described in Note 6 – Risk management consist of the following:

*(millions of dollars)*

	September 30, 2008		
	Natural gas non-hedges	Foreign exchange non-hedges	Total
<b>Derivative instruments assets:</b>			
<b>Current</b>	\$ 24.8	\$ 6.4	\$ 31.2
<b>Non-current</b>	48.5	5.1	53.6
<b>Derivative instruments liabilities:</b>			
<b>Current</b>	-	(0.6)	(0.6)
<b>Non-current</b>	-	(4.2)	(4.2)
	<b>\$ 73.3</b>	<b>\$ 6.7</b>	<b>\$ 80.0</b>
<b>Net notional amounts:</b>			
<b>Gigajoules (GJs)(millions)</b>	67		
<b>US foreign exchange (US dollars in millions)</b>		341.1	
<b>Contract terms (years)</b>	2 to 8	1 to 6	

*(millions of dollars)*

	December 31, 2007		
	Natural gas non-hedges	Foreign exchange non-hedges	Total
<b>Derivative instruments assets:</b>			
<b>Current</b>	\$ 20.7	\$ 14.3	\$ 35.0
<b>Non-current</b>	42.9	22.3	65.2
<b>Derivative instruments liabilities:</b>			
<b>Current</b>	-	(0.3)	(0.3)
<b>Non-current</b>	-	(2.9)	(2.9)
	<b>\$ 63.6</b>	<b>\$ 33.4</b>	<b>\$ 97.0</b>
<b>Net notional amounts:</b>			
<b>Gigajoules (GJs)(millions)</b>	75		
<b>US foreign exchange (US dollars in millions)</b>		280.6	
<b>Contract terms (years)</b>	3 to 9	1 to 6	

The fair value of derivative instruments are determined, where possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask, or closing market prices, as appropriate in active markets. Where there are limited observable prices due to illiquid or inactive markets, the Partnership uses appropriate valuation and price modeling commonly

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used by market participants to estimate fair value. Fair value determined using valuation models requires the use of assumptions concerning the amount and timing of future cash flows. In general, fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates as the discount rates for time value, and volatility for all of the Partnership's financial instruments. It is possible that the assumption used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

The extent to which fair value of derivatives are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. With respect to natural gas, the Partnership has determined the market is active within five years. As the natural gas supply contracts extend beyond the active period of the market, fair value is determined by reference in part to published price quotations where there is observable market data and in part by relying on price forecasts prepared by an independent third party where there are limited observable natural gas prices. While external market forecasts outside the active period of the market reasonably reflect all factors that market participants would consider in setting a price, these expectations are not currently supportable by active forward market quotes. The fair values of these contracts could change significantly if the assumptions were changed to reasonably possible alternatives. The natural gas prices forecasts for the period where limited observable natural gas prices are available range from \$7.63/GJ to \$7.89/GJ. The Partnership has determined that a reasonably possible increase or decrease of \$1.00/GJ in the natural gas price forecast would have a \$59.2 million impact on the fair value estimate of these contracts. Included in this sensitivity is a \$20.1 million impact for contract periods beyond the next five years where natural gas prices are not based on observable prices. The valuation technique used where there are limited observable natural gas prices resulted in unrealized pre-tax fair value losses of \$42.9 million and unrealized pre-tax fair value gains of \$7.6 million recognized in fuel expense for the three and nine months ended September 30, 2008 (\$15.7 million unrealized pre-tax fair value losses and \$0.4 million unrealized pre-tax fair value gains for the three and nine months ended September 30, 2007).

Unrealized and realized pre-tax gains and losses on derivative instruments recognized in net income were:

<i>(millions of dollars)</i>	Income statement category	Net gains (losses) for the three months ended September 30		Net gains (losses) for the nine months ended September 30	
		2008	2007	2008	2007
Foreign exchange non-hedges	Revenue	\$ (11.1)	\$ 16.9	\$ (13.3)	\$ 43.0
Natural gas non-hedges	Cost of fuel	(160.5)	(52.7)	9.8	(68.2)
Foreign exchange non-hedges	Foreign exchange losses (gains)	0.1	-	(0.1)	(20.0)
Interest rate non-hedges	Financial charges and other, net	-	(6.9)	-	(3.6)

## **Note 6. Risk management**

### **Risk management overview**

The Partnership is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments which include market, credit and liquidity risks. The Partnership's overall risk management process is designed to identify, manage and mitigate business risk which includes financial risk, among others. Financial risk is managed according to objectives, targets and policies set forth by the Board of Directors. Risk management strategies, policies and limits are designed to ensure the risk exposures are managed within the Partnership's business objectives and risk tolerance. The Partnership's risk management objective is to protect and minimize volatility in cash provided by operating activities and distributions therefrom.

### **Market risk**

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates and equity prices. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and composition of the Partnership's financial assets and liabilities held, non-trading physical assets and contract portfolios. Commodity price risk management and the associated credit risk management are carried out in accordance with Partnership's financial risk management policies, as approved by the Board of Directors.

To manage the exposure related to changes in market risk, the Partnership uses various risk management techniques including the use of derivative instruments. Derivative instruments may include financial and physical forward contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Market risk exposures are monitored regularly against approved risk limits and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts. The Partnership's actual exposure to market risks is constantly changing as the Partnership's portfolio of debt, foreign currency and commodity contracts change. Changes in fair value based on market variable fluctuations cannot be extrapolated as the relationship between the change in the market variable and the change in fair value may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Partnership.

#### *Commodity price risk*

The Partnership is exposed to commodity price risk as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and coal. The Partnership actively manages commodity price risk by optimizing its asset and contract portfolios in the following manner:

- The Partnership commits substantially all of its power supply to long-term fixed price PPAs with investment grade power buyers, which limits the exposure to electricity prices;
- The Partnership purchases natural gas under long-term fixed price supply contracts to reduce the exposure to natural gas prices on its natural gas-fired generation plants; and
- The Partnership has entered into PPAs whereby the counterparty is responsible for providing the natural gas or variable costs linked to the price of natural gas or coal are born by the counterparty.

The fair value of the Partnership's commodity related derivatives as at September 30, 2008, that are required to be measured at fair value with the respective changes in fair value recognized in net income, are disclosed in Note 5 – Financial instruments.

The following represents the sensitivity of net income to derivative instruments that are accounted for on a fair value basis. As at September 30, 2008, with all other variables unchanged, a \$1.00/GJ increase (decrease) of the natural gas price is estimated to increase (decrease) net income by approximately \$49 million after tax. This assumption is based on the volumes or position held at September 30, 2008. There would be no impact to other comprehensive income.

#### *Foreign exchange risk*

The Partnership is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments and monetary assets and liabilities (transactional exposure). The Partnership operates in the US and therefore, foreign exchange risk exposures arise from transactions denominated in US dollars. The risk is that the Canadian dollar value of US dollar cash flows will vary as a result of the movements in exchange rates.

The Partnership's foreign exchange management policy is to minimize economic and material transactional exposures arising from movements in the Canadian dollar against the US dollar. The Partnership's foreign currency exposure arises from anticipated US dollar denominated cash flows from its US operations and from debt service obligations on US dollar borrowings. The Partnership coordinates and manages foreign currency risk through the General Partner's central Treasury function. Foreign exchange risk is managed by considering naturally occurring opposite movements wherever possible and then managing any material residual foreign currency exchange risks according to the policies approved by the Board of Directors.

The Partnership primarily uses foreign currency forward contracts to fix the Canadian currency equivalent of its US currency cash flows thereby reducing its anticipated US denominated transactional exposure. The Partnership's foreign currency risk management practice is to ensure a majority of the net currency exposure on anticipated transactions within 7 years be economically hedged. At September 30, 2008, US\$341.0 million or approximately 82% of future anticipated net cash flows from its US plants were economically hedged for 2008 to 2014 at a weighted average rate of \$1.08 per US \$1.00.

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The following table summarizes the non-derivative and derivative financial instruments denominated in US dollars:

<i>(millions of US dollars)</i>	<b>September 30 2008</b>	December 31 2007
<b>Non-derivative financial instruments:</b>		
Cash and cash equivalents	9.6	11.0
Accounts receivable	47.3	41.9
Accounts payable	(17.5)	(37.6)
Other assets - net investment in lease	27.6	28.8
Long-term debt	(412.6)	(412.4)
	<b>\$ (345.6)</b>	<b>\$ (368.3)</b>
<b>Forward foreign exchange contracts:</b>		
Forward foreign exchange sales	(397.8)	(352.2)
Forward foreign exchange purchases	56.8	71.6
	<b>\$ (341.0)</b>	<b>\$ (280.6)</b>
<b>Net exposure</b>	<b>(686.6)</b>	<b>(648.9)</b>
<b>Significant exchange rates in Canadian dollars per US dollar:</b>		
Average reporting date closing	1.06	0.99
Average forward rate inherent in sales contracts	1.08	0.90
Average forward rate inherent in purchase contracts	1.06	0.96

As at September 30, 2008, holding all other variables constant, a \$0.10 strengthening (weakening) of the Canadian dollar against the US dollar would increase (decrease) net income by approximately \$60 million after tax. There would be no impact to other comprehensive income.

*Interest rate risk*

The Partnership is exposed to changes in interest rates on its cash and cash equivalents and floating rate short-term and long-term obligations. The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At September 30, 2008 the Partnership held \$17.0 million in floating rate debt (December 31, 2007 – nil). The Partnership may also use derivative instruments to manage interest rate risk. At September 30, 2008 and December 31, 2007 the Partnership did not hold any interest rate derivative instruments.

Holding all other variables constant and assuming that the amount and mix of floating rate debt remains unchanged from that held at September 30, 2008, a 1% change to interest rates would have a \$0.2 million impact on full year net income and would have no impact on other comprehensive income.

*Equity price risk*

The Partnership is exposed to changes in equity prices arising from its 14.2% preferred share interest in PERH which is classified as an available for sale financial asset. The investment in PERH is carried at the original exchange amount less any impairment because the PERH shares are not quoted in an active market and therefore fair value cannot be measured reliably. Refer to Note 5 – Financial instruments for disclosures on available for sale financial assets.

**Credit risk**

The Partnership has exposure to credit risk associated with counterparty default under the Partnership's power and steam sales contracts, energy supply agreements and foreign currency hedges. In the event of a default by a counterparty, existing PPAs and energy supply agreements may not be replaceable on similar terms as pricing in many of these agreements is favourable relative to their current markets. Credit risk is associated with the ability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. Credit risk is managed by making appropriate credit assessments of counterparties on an ongoing basis, dealing with creditworthy counterparties, diversifying the risk by using several counterparties and where appropriate and contractually allowed, requiring the counterparty to provide appropriate security.

*Maximum credit risk exposure*

The Partnership has the following financial assets that are exposed to credit risk:

	September 30, 2008		
	Canada	US	Total
Trade receivables	\$ 17.2	\$ 50.3	\$ 67.5
Other assets - net investment in lease	-	29.4	29.4
Derivative instruments assets - current	31.2	-	31.2
Derivative instruments assets - non-current	53.6	-	53.6
	<u>\$ 102.0</u>	<u>\$ 79.7</u>	<u>\$ 181.7</u>

The maximum credit exposure of these assets is their carrying value. No amounts were held as collateral at September 30, 2008.

*Accounts receivable*

Accounts receivable consist primarily of amounts due from customers including industrial and commercial customers, government-owned or sponsored entities, regulated public utility distributors and other counterparties. Historically the Partnership has not experienced credit losses and accordingly has not provided for an allowance for doubtful accounts. The Partnership evaluates the need for an allowance for potential credit losses by reviewing any overdue accounts and monitoring changes in the credit profiles of counterparties. The Partnership mitigates its credit risk exposures by dealing with creditworthy counterparties and, where appropriate, taking back appropriate security from the counterparty.

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At September 30, 2008, no material accounts receivable were past due and there was no provision for credit losses associated with receivables and financial derivative instruments as all balances are considered to be fully recoverable.

### Liquidity risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they come due. The Partnership's liquidity is managed centrally through the General Partner's central Treasury function. The Partnership manages liquidity through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities and access to capital markets.

As at September 30, 2008, the Partnership had undrawn and committed bank credit facilities of \$283.0 million with remaining terms of approximately two years. On October 2, 2008, one of the committed bank credit facilities was extended and it presently has a remaining term of approximately three years. The Partnership also has a long-term debt rating of BBB+ and BBB (high), assigned by Standard and Poor's (S&P) and DBRS Limited (DBRS) respectively.

In addition, the Partnership has a Canadian shelf prospectus under which it may raise up to \$1.0 billion in partnership units or debt securities, of which a maximum of \$600.0 million can be medium term notes. The Canadian shelf prospectus expires in August 2010.

The following are the undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments as at September 30, 2008:

(millions of dollars)	Within 1 year	Between 1 & 2 years	Between 2 & 3 years	Between 3 & 4 years	Between 4 & 5 years	Beyond 5 years	Total
Non-derivative financial liabilities:							
Long-term debt <sup>(1)</sup>	\$ 18.3	\$ 1.4	\$ -	\$ -	\$ -	\$ 651.6	\$ 671.3
Interest payments on long-term debt	38.8	38.7	38.6	38.6	38.5	366.9	560.1
Accounts payable and accrued liabilities <sup>(2)</sup>	33.9	-	-	-	-	-	33.9
Distributions payable	34.0	-	-	-	-	-	34.0
Derivative financial liabilities:							
Net forward exchange contracts	\$ 0.6	\$ 0.8	\$ 0.9	\$ 0.6	\$ 0.8	\$ 1.8	\$ 5.5
Total	\$ 125.6	\$ 40.9	\$ 39.5	\$ 39.2	\$ 39.3	\$ 1,020.3	\$ 1,304.8

<sup>(1)</sup> Excluding deferred financing charges of \$5.1 million.

<sup>(2)</sup> Excluding interest on long-term debt of \$7.8 million and non-cash accruals of \$2.5 million.

### Note 7. Capital management

The Partnership's primary objectives when managing capital are to safeguard the Partnership's ability to continue as a going concern, provide stable distributions to unitholders, to maintain an investment grade credit rating and to facilitate the acquisition or development of power projects in Canada and the United States consistent with the growth strategy of the Partnership. The

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Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. This overall objective and policy for managing capital remained unchanged in the third quarter of 2008 from the prior comparative period.

The Partnership considers its capital structure to consist of long-term debt, preferred shares and partners' equity. The following table represents the total capital of the Partnership:

<i>(millions of dollars)</i>	<b>September 30 2008</b>	December 31 2007
Long-term debt (including current portion)	\$ 666.2	\$ 619.7
Preferred shares	122.0	122.0
Partners' equity	806.2	905.7
Total capital	<b>\$ 1,594.4</b>	<b>\$ 1,647.4</b>

The Partnership's credit and stability ratings are presented in the following table:

	<b>September 30 2008</b>	December 31 2007
Credit rating		
S&P	<b>BBB+</b>	BBB+
DBRS	<b>BBB(high)</b>	BBB(high)
Stability rating		
S&P	<b>SR-2</b>	SR-2
DBRS	<b>STA-2</b>	STA-2

The Partnership has the following externally imposed requirements on its capital:

- The Partnership must maintain a debt to total capitalization ratio, as defined in the debt agreements, of not more than 65%; and
- In the event the Partnership is assigned a rating of less than BBB+ by S&P and BBB(high) by DBRS, the Partnership also would be required to maintain a ratio of earnings before interest, income taxes, depreciation and amortization to interest expense of not less than 2.5 to 1.

During the period the Partnership's debt to capitalization ratio was 45% (December 31, 2007 – 41%) and a rating of BBB+ and BBB(high) was assigned by S&P and DBRS respectively (December 31, 2007 – BBB+ and BBB(high)).

In order to manage the capital structure, the Partnership may adjust the amount of distributions paid to unitholders, issue or redeem preferred shares, issue or repay debt or issue or buy back partnership units.

## Note 8. Segment disclosures

The Partnership operates in one reportable business segment involved in the operation of electrical generation plants within British Columbia, Ontario and in the US in California, Colorado, New Jersey, New York, North Carolina and Washington State.

### Geographic information

<i>(millions of dollars)</i>	Three months ended September 30			Three months ended September 30		
	2008			2007		
	Canada	US	Total	Canada	US	Total
Revenue	\$ 41.5	\$ 96.5	\$ 138.0	\$ 65.6	\$ 87.8	\$ 153.4

  

<i>(millions of dollars)</i>	Nine months ended September 30			Nine months ended September 30		
	2008			2007		
	Canada	US	Total	Canada	US	Total
Revenue	\$ 147.3	\$ 259.4	\$ 406.7	\$ 196.5	\$ 265.1	\$ 461.6

  

<i>(millions of dollars)</i>	As at September 30, 2008			As at December 31, 2007		
	Canada	US	Total	Canada	US	Total
<b>Assets</b>						
PP&E	\$ 562.6	\$ 466.3	\$ 1,028.9	\$ 581.3	\$ 471.6	\$ 1,052.9
PPAs	40.5	387.5	428.0	42.8	410.4	453.2
Other assets	-	29.9	29.9	-	30.2	30.2
Goodwill	-	50.9	50.9	-	50.9	50.9
<b>Total assets</b>	<b>\$ 603.1</b>	<b>\$ 934.6</b>	<b>\$ 1,537.7</b>	<b>\$ 624.1</b>	<b>\$ 963.1</b>	<b>\$ 1,587.2</b>

## Note 9. Commitments

The Partnership has committed up to US\$80 million for the enhancement of the Southport and Roxboro facilities, to be spent over 2008 and 2009.

## Note 10. Proposed acquisition

On September 11, 2008, the Partnership announced an agreement to acquire 100% of the equity interest in Morris Cogeneration LLC (Morris) from Diamond Generating Corporation and MIC Nebraska, Inc., both wholly-owned subsidiaries of Mitsubishi Corporation for an aggregate purchase price of US\$73 million subject to closing adjustments. Morris is a 177 megawatt natural gas-fired cogeneration facility located on Equistar Chemicals LP's (Equistar) chemical plant in Morris, Illinois.

The acquisition is expected to close in the fourth quarter of 2008 and will be financed under the Partnership's existing credit facilities with permanent financing to be arranged after the close of the transaction, depending on the requirements of the Partnership.

All of the steam and a portion of the electricity produced from Morris are sold to Equistar under the terms of a long-term energy services agreement which expires in 2023. Equistar, a wholly-owned subsidiary of Lyondell Chemical Company, produces ethylene and its co-products and derivatives including polyethylene plastic, at its plant in Morris. Morris also has an electric

capacity agreement with Exelon Generation Company, LLC that terminates in 2011, for capacity and electricity in excess of the needs of Equistar and can participate in the Pennsylvania, New Jersey, and Maryland market.

**Note 11. Comparative figures**

Certain comparative figures have been reclassified to conform to the current year's presentation.

For further information on the Partnership visit [www.epcorpowlp.ca](http://www.epcorpowlp.ca) or contact:

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