

EPCOR Power L.P.

FOR RELEASE AT 6:00 P.M. MDT, July 28, 2009

EPCOR Power L.P. reports second quarter results

Edmonton, Alberta – July 28, 2009 (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 June 30, 2009.

"Financial and operating results in the second quarter were generally in-line with our expectations," said Stuart Lee, President of the General Partner of EPCOR Power L.P. "Cash provided by operating activities from continuing operations excluding working capital changes was \$38.3 million in the quarter, being higher than the \$29.5 million for the same period last year. The quarter benefitted from higher contributions from the Curtis Palmer and Williams Lake facilities and additional contribution from the Morris facility acquired in October 2008, which were offset by lower power demand in the Ontario and North Carolina regions that negatively impacted the financial performance of our plants in those areas."

"In June, we announced an enhanced approach to positioning the Partnership for long term distribution sustainability that addresses current financing requirements and positions it for future growth," said Mr. Lee. "This quarter marks the beginning of that approach. The use of retained cash will enable the Partnership to permanently finance the Southport and Roxboro construction, the North Island and Oxnard repowering projects and the Morris acquisition. With greater liquidity and an improved balance sheet, it will allow more flexible financing solutions to fund future growth."

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

Operational and Financial Highlights <i>(unaudited)</i>	Three months ended		Six months ended	
	June 30		June 30	
<i>(millions of dollars except per unit and operational amounts)</i>	2009	2008	2009	2008
Power generated (GWh)	1,030	1,065	2,331	2,319
Weighted average plant availability	90%	87%	92%	92%
Revenue	165.2	143.9	292.8	262.0
Net income from continuing operations	42.3	105.1	9.7	158.4
Per unit	\$0.78	\$1.95	\$0.18	\$2.94
Net income	42.8	104.9	9.5	158.3
Per unit	\$0.79	\$1.95	\$0.18	\$2.94
Comprehensive income (loss)	1.8	103.9	(14.8)	156.4
Cash provided by operating activities of continuing operations	33.1	39.4	66.8	81.0
Per unit ⁽¹⁾	\$0.61	\$0.73	\$1.24	\$1.50
Cash distributions	23.7	33.9	57.7	67.9
Per unit	\$0.44	\$0.63	\$1.07	\$1.26
Capital expenditures	25.9	10.0	42.9	13.4
Weighted average units outstanding (millions)	53.9	53.9	53.9	53.9

⁽¹⁾ Cash provided by operating activities of continuing operations per unit is a non-GAAP financial measure that is defined in the interim MD&A.

The June 30, 2009 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) and will be available on SEDAR (www.sedar.com).

EPCOR Power L.P.

Management's Discussion and Analysis

For the Six Months Ended June 30, 2009

This management's discussion and analysis (MD&A) is dated July 28, 2009 and should be read in conjunction with the unaudited interim consolidated financial statements of EPCOR Power L.P. (collectively with its subsidiaries, the Partnership, unless otherwise specifically stated) for the six months ended June 30, 2009 and the audited consolidated financial statements and MD&A of the Partnership for the year ended December 31, 2008. Additional information relating to the Partnership, including the 2008 Annual Information Form and continuous disclosure documents are available on SEDAR at 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 25 of this report.

On July 9, 2009, as part of the transfer by EPCOR Utilities Inc. (EPCOR) of a 27.8% interest in its power generation business to Capital Power Corporation (collectively with its subsidiaries, CPC, unless otherwise indicated), (i) EPLP Investments Inc. (EPLP Investments) acquired 16,513,504 limited partnership units in the capital of the Partnership, representing 30.6% of the total outstanding units of the Partnership, and all of the common shares of EPCOR Power Services Ltd., the General Partner of the Partnership, and (ii) CPC acquired 100% ownership of the companies that provide management and operations services to the Partnership and its subsidiaries pursuant to management and operations agreements. EPCOR owns all of the 51 voting, non-participating shares of EPLP Investments and CPC owns all of the 49 voting, participating shares of EPLP Investments.

The General Partner is responsible for management of the Partnership. The Board of Directors (the Board) of the General Partner declares the cash distributions to the Partnership's unitholders. The General Partner has engaged EPCOR Regional Power Services L.P. and Capital Power Operations (U.S.A.) Inc., both wholly-owned subsidiaries of CPC (collectively herein, 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 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.

SIGNIFICANT EVENTS

Distribution reduction

In the second quarter, the Partnership reduced its distribution to \$0.44 per quarter from \$0.63 per quarter which targets a long term payout ratio of approximately 75% of cash provided by operating activities less maintenance capital. Payout ratio is Partnership distributions divided by cash provided by operating activities less maintenance capital. The reduction in cash distributions was made to position the Partnership for long term distribution sustainability that addresses current financing requirements and positions it for future growth. The Partnership believes the new distribution level is sustainable for at least the next five years based on existing cash flows regardless of whether it remains a partnership or converts to a corporate form. The retained cash will be applied toward the permanent financing of the Southport and

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Roxboro construction, the North Island and Oxnard repowering projects (see Liquidity and Capital Recourses – Capital Expenditures) and the Morris acquisition and will be available to fund internal and external development opportunities as well as acquisitions.

Completion of the North Island repowering

The Partnership completed the replacement of the existing GE LM5000 natural gas turbine with a more efficient and reliable GE LM6000 at North Island at a cost of approximately US\$17.6 million, lower than the original estimated cost of US\$19 million. The repowering project was completed on May 1, 2009, in time for the summer peak demand season in Southern California.

Change to relationship with CPC

The Partnership and the Manager have agreed to a revised incentive fee of 10% of any Annual Distributable Cash Flow (as defined) greater than \$2.40 per unit effective June 30, 2009 to better align the incentives of the Manager to increase the amount of cash available for distribution to unitholders. For the purposes of the incentive fee, Annual Distributable Cash Flow is defined as cash flow from operating activities before changes in non-cash working capital plus dividends from Primary Energy Recycling Holdings LLC (PERH), less scheduled debt repayments and maintenance capital.

The Partnership and each of EPCOR and CPC have agreed to a standstill whereby CPC and EPCOR are not able to increase their ownership in EPLP without the consent of the independent directors of the General Partner until July 1, 2010, subject to certain exceptions relating to maintaining the minimum 30% interest in EPLP.

Furthermore, the Partnership and CPC have agreed to an approach for both partners to work together early in the process to review CPC development opportunities that the Partnership might have an interest in participating and acquisitions under the Partnership’s right of first look. The Partnership has been granted a right of first look on the sale of CPC generation assets in addition to its right of first look in relation to potential acquisitions.

<i>(millions of dollars)(unaudited)</i>	Three months	Six months
Cash provided by operating activities of continuing operations for the three and six months ended June 30, 2008	39.4	81.0
Higher operating margin at Curtis Palmer	4.5	3.7
Contribution of Morris acquired October 31, 2008, excluding interest paid	3.5	5.9
Higher operating margin at Williams Lake	3.1	1.6
Lower management and administration costs	2.1	1.3
Changes in operating working capital	(15.1)	(16.1)
Lower operating margin at the North Carolina plants	(3.6)	(6.6)
Lower operating margin at the Ontario plants	(2.5)	(4.2)
Higher interest expenses	(1.4)	(3.2)
Other	3.1	3.4
Cash provided by operating activities of continuing operations for the three and six months ended June 30, 2009	33.1	66.8

The Partnership reported cash provided by operating activities of continuing operations of \$33.1 million or \$0.61 per unit for the quarter ended June 30, 2009 compared to \$39.4 million or \$0.73 per unit for the same period in 2008. Cash provided by operating activities of continuing

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operations per unit is defined below under Non-GAAP Measures. The \$6.3 million decrease in cash provided by operating activities of continuing operations for the second quarter of 2009 compared to the second quarter of 2008 was primarily due to the following:

- A \$5.2 million increase in working capital in the three months ended June 30, 2009 compared to a \$9.9 million decrease during the same period in the prior year. Working capital increased in 2009 primarily due to the timing of payments of interest and incentive fees;
- Operating margin was \$3.6 million lower at the North Carolina plants due to higher maintenance costs and lower generation due to decreased power demand and increased competition from natural gas plants in the region;
- Operating margin was \$2.5 million lower at the Ontario plants primarily due to lower enhancement profits as lower natural gas prices reduced the opportunity to curtail operations and re-sell contracted natural gas at market prices; and
- Higher interest expenses of \$1.4 million were incurred due to the impact of a stronger US dollar relative to the Canadian dollar on US dollar interest expenses and interest on draws under the Partnership’s revolving credit facilities to finance the acquisition of the Morris facility.

Decreases were partially offset by the following:

- Operating margin was \$4.5 million higher at Curtis Palmer due to a step-up in pricing under the power purchase arrangement (PPA) of 18% in December 2008 and higher generation due to higher water flows;
- The Morris facility, which was acquired on October 31, 2008, provided \$3.5 million of operating margin;
- Operating margin was \$3.1 million higher at Williams Lake due to a planned outage to complete a major overhaul in the second quarter of 2008, partially offset by higher pricing in 2008 to offset the lower generation caused by the outage; and
- Lower administrative costs primarily due to lower incentive fees as a result of the distribution reduction on the incentive calculation for the six months ended June 30, 2009 and changes in the method of determining the incentive fees thereafter (see Significant Events – Changes to Relationship with CPC).

The Partnership reported cash provided by operating activities of continuing operations of \$66.8 million or \$1.24 per unit for the six months ended June 30, 2009 compared with \$81.0 million or \$1.50 per unit for the same period in 2008. Cash provided by operating activities of continuing operations per unit is defined below under Non-GAAP Measures. The \$14.2 million decrease in cash provided by operating activities of continuing operations for the six months ended June 30, 2009 compared to the same period in 2008 is primarily due to the items described above for the current quarter.

<i>(millions of dollars)(unaudited)</i>	Three months	Six months
Cash provided by operating activities for the three and six months ended June 30, 2008	40.4	83.3
Decrease in cash provided by operating activities of continuing operations – see previous table	(6.3)	(14.2)
Decrease in cash provided by operating activities of Castleton	(2.5)	(5.1)
Cash provided by operating activities for the three and six months ended June 30, 2009	31.6	64.0

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The Partnership reported cash provided by operating activities of \$31.6 million and \$64.0 million for the three and six months ended June 30, 2009 compared to \$40.4 million and \$83.3 million for the same periods in 2008. The decrease in cash provided by operating activities of Castleton in the three and six months ended June 30, 2009 compared to the same periods in 2008 was due to lower cash provided by operating activities after the expiry of its PPA in June 2008.

<i>(millions of dollars)(unaudited)</i>	Three months	Six months
Net income from continuing operations for the three and six months ended June 30, 2008	105.1	158.4
Decrease in income tax expense	8.5	21.8
Higher operating margin at Curtis Palmer	4.5	3.7
Contribution of Morris acquired October 31, 2008, excluding interest paid	3.5	5.9
Higher operating margin at Williams Lake	3.1	1.6
Lower management and administration costs	2.1	1.3
Fair value changes on natural gas supply and foreign exchange contracts	(73.5)	(176.1)
Lower operating margin at the North Carolina plants	(3.6)	(6.6)
Foreign exchange (gains) losses in 2008	(2.8)	9.9
Lower operating margin at the Ontario plants	(2.5)	(4.2)
Higher depreciation and amortization mainly due to the Morris acquisition in 2008	(1.6)	(3.3)
Higher interest expenses	(1.4)	(3.2)
Other	0.9	0.5
Net income from continuing operations for the three and six months ended June 30, 2009	42.3	9.7

Net income from continuing operations was \$42.3 million or \$0.78 per unit for the quarter ended June 30, 2009 compared to net income of \$105.1 million or \$1.95 per unit for the same period in 2008. In addition to the items described above for the change in cash provided by operating activities, the decrease in net income of \$62.8 million was the result of the following:

- A net gain of \$35.2 million was recorded in the second quarter of 2009 on the change in the fair value of the natural gas supply and foreign exchange contracts compared to \$108.7 million in the second quarter of 2008. The majority of the changes in fair value are the result of a strengthening of future prices for the Canadian dollar relative to the US dollar in the second quarter of 2009 compared to increases in future prices for natural gas in the second quarter of 2008; and
- In the fourth quarter of 2008, the Partnership re-evaluated the functional currency of its US subsidiaries and determined it to be US dollars. Accordingly, gains and losses on foreign currency translation are accumulated as a component of partners’ equity commencing in the fourth quarter of 2008. The Partnership reported net foreign exchange gains of \$2.7 million and losses of \$10.5 million for the three and six months ended June 30, 2008.

Decreases were partially offset by the following:

- An income tax expense of \$6.3 million was recorded in the second quarter of 2009 compared to \$14.8 million in 2008. The change was mainly due to future income taxes on changes in temporary differences primarily related to changes in the fair value of natural gas and foreign exchange contracts.

Net income from continuing operations was \$9.7 million or \$0.18 per unit for the six months ended June 30, 2009 compared with \$158.4 million or \$2.94 per unit for the same period in 2008. The \$148.7 million decrease in net income from continuing operations for the six months

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ended June 30, 2009 compared to the same period in 2008 is primarily due to the items described above for the current quarter.

<i>(millions of dollars)(unaudited)</i>	Three months	Six months
Net income for the three and six months ended June 30, 2008	104.9	158.3
Decreases in the net income from continuing operations – see previous table	(62.8)	(148.7)
Increase (decrease) in net income from Castleton	0.7	(0.1)
Net income for the three and six months ended June 30, 2009	42.8	9.5

NON-GAAP MEASURES

The Partnership uses operating margin as a performance measure and cash provided by operating activities of continuing operations 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 from continuing operations before tax and preferred share dividends is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Operating margin	87.7	155.1	86.9	261.9
Deduct (Add):				
Depreciation and amortization	23.3	21.7	47.1	43.8
Management and administration	2.9	5.0	7.2	8.5
Foreign exchange losses (gains)	0.1	(2.7)	0.6	10.5
Equity losses in PERH	0.6	0.4	2.3	2.1
Financial charges and other, net	10.5	9.1	21.4	18.2
Net income from continuing operations before tax and preferred share dividends	50.3	121.6	8.3	178.8

Cash provided by operating activities of continuing operations per unit is cash provided by operating activities of continuing operations (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, 2008 reporting.

CHANGES IN ACCOUNTING POLICIES

Commencing January 1, 2009, the Partnership adopted new accounting guidelines and standards as issued by the Canadian Institute of Chartered Accountants (CICA) for credit risk and the fair value of financial assets and financial liabilities as well as goodwill and intangible assets.

Credit risk and the fair value of financial assets and financial liabilities

On January 20, 2009 the Emerging Issues Committee of the CICA issued EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Effective January 1, 2009, the Partnership adopted the recommendations of EIC-173 and applied the recommendations retrospectively without restatement of prior periods. On January 1, 2009, the Partnership made the following adjustments to the balance sheet to adopt the recommendations of EIC-173:

Balance sheet item	Increase (decrease)	Explanation
Derivative instruments assets	(1.5)	Impact to fair value of foreign exchange and natural gas contracts from incorporating credit risk of counterparties of the Partnership.
Derivative instruments liabilities	(6.3)	
Future income taxes liabilities - non-current	0.9	Tax impact from adoption of new standard.
Opening deficit	(3.9)	After tax impact to opening deficit resulting from adoption of new standard.

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 provisions in International Financial Reporting Standards (IFRS). The Partnership adopted these amendments January 1, 2009 which did not result in a material transition adjustment to the financial statements. The new accounting standard has been applied prospectively and the comparative financial statements have not been restated.

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REVENUE, OPERATING MARGIN⁽¹⁾ AND PLANT OUTPUT

<i>(millions of dollars except GWh) (unaudited)</i>	Three months ended June 30					
	2009			2008		
	GWh	Revenue	Operating Margin ⁽¹⁾	GWh	Revenue	Operating Margin ⁽¹⁾
Ontario plants	298	\$ 32.5	\$ 9.7	272	\$ 38.7	\$ 12.2
Williams Lake	32	10.1	5.8	85	7.2	2.7
Mamquam and Queen Charlotte	90	5.5	4.4	86	5.6	4.4
Northwest US plants	122	16.4	9.3	111	14.1	8.4
California plants	220	24.7	9.5	222	41.3	9.7
Curtis Palmer	99	13.0	11.6	84	8.4	7.1
Northeast US natural gas plants ⁽²⁾	162	21.4	4.7	44	6.8	0.9
North Carolina plants	7	6.7	(3.2)	161	15.0	0.4
PERC management fees		1.0	0.7		0.9	0.6
	1,030	131.3	52.5	1,065	138.0	46.4
Fair value changes						
Foreign exchange contracts		33.9	33.9		5.9	5.9
Natural gas supply contracts		-	1.3		-	102.8
	1,030	\$ 165.2	\$ 87.7	1,065	\$ 143.9	\$ 155.1

<i>(millions of dollars except GWh) (unaudited)</i>	Six months ended June 30					
	2009			2008		
	GWh	Revenue	Operating Margin ⁽¹⁾	GWh	Revenue	Operating Margin ⁽¹⁾
Ontario plants	686	\$ 76.2	\$ 29.5	622	\$ 81.9	\$ 33.7
Williams Lake	169	21.1	12.7	222	18.1	11.1
Mamquam and Queen Charlotte	119	8.0	5.9	114	8.1	5.7
Northwest US plants	336	32.1	18.2	305	29.0	17.1
California plants	449	46.5	11.0	465	71.1	12.7
Curtis Palmer	189	23.2	20.3	192	19.1	16.6
Northeast US natural gas plants ⁽²⁾	328	48.9	8.6	83	14.5	1.8
North Carolina plants	55	17.2	(5.5)	316	27.9	1.1
PERC management fees		1.9	1.3		1.7	1.2
	2,331	275.1	102.0	2,319	271.4	101.0
Fair value changes						
Foreign exchange contracts		17.7	17.7		(9.4)	(9.4)
Natural gas supply contracts		-	(32.8)		-	170.3
	2,331	\$ 292.8	\$ 86.9	2,319	\$ 262.0	\$ 261.9

⁽¹⁾ 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".

⁽²⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

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Weighted average plant availability ⁽¹⁾	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Ontario plants	94%	93%	96%	96%
Williams Lake	91%	62%	95%	81%
Mamquam and Queen Charlotte	99%	87%	90%	83%
Northwest US plants	93%	80%	96%	90%
California plants	92%	93%	89%	91%
Curtis Palmer	65%	99%	82%	100%
Northeast US natural gas plants ⁽²⁾	98%	98%	98%	95%
North Carolina plants	67%	95%	71%	97%
Weighted average total	90%	87%	92%	92%

⁽¹⁾ 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.

⁽²⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

Operating margin excluding fair value changes in foreign exchange and natural gas supply contracts for the three and six months ended June 30, 2009 increased by \$6.1 million and \$1.0 million respectively compared to the same periods in 2008. The increases were primarily the result of the acquisition of Morris on October 31, 2008 and a step-up in pricing under the Curtis Palmer PPA of 18% partially offset by lower dispatch of the North Carolina plants.

Revenue excluding fair value changes in foreign exchange contracts for the three months ended June 30, 2009 decreased by \$6.7 million compared to the same period in 2008 due to decreased electricity prices at the California plants driven by lower natural gas prices and lower dispatch of the North Carolina plants partially offset by the acquisition of Morris on October 31, 2008. The increase in revenue excluding fair value changes in foreign exchange contracts of \$3.7 million for the six months ended June 30, 2009 compared to the same period in 2008 was the result of the same factors, however, pricing at the California facilities and dispatch of the North Carolina facilities were higher in the first quarter of 2009 compared to the second quarter of 2009.

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, future power sales or future US dollar cash flows.

Ontario Plants

The Ontario plants reported operating margin of \$9.7 million and \$29.5 million for the three and six months ended June 30, 2009 compared to \$12.2 million and \$33.7 million for the same periods in 2008. The decreases were primarily due to lower natural gas prices, lower power demand in Ontario and lower revenues from waste heat. The lower natural gas prices have resulted in lower enhancement profits but have reduced waste heat optimization costs, natural gas transportation costs and the cost of spot natural gas purchases. Lower electrical demand has resulted in curtailment of operations at Kapuskasing and North Bay during off peak periods by the PPA counterparty.

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Revenue from Ontario plants <i>(millions of dollars)(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
Power	29.2	26.3	71.7	66.2
Enhancements	0.4	8.0	0.6	10.7
Gas diversions	2.9	4.4	3.9	5.0
	32.5	38.7	76.2	81.9

Revenues from the Ontario plants were lower for the three and six months ended June 30, 2009 compared to the same periods in 2008 due to lower waste heat availability, lower enhancement activity and lower prices for diverted natural gas, partially offset by increased power sales. Revenues from waste heat declined 11% and 7% for the three and six months ended June 30, 2009 compared to the same periods in 2008 respectively as a result of lower throughput on TransCanada Corporation’s Canadian Mainline, the natural gas transmission line to Northern Ontario.

Williams Lake

Operating margin from Williams Lake was \$5.8 million and \$12.7 million for the three and six months ended June 30, 2009, compared to \$2.7 million and \$11.1 million for the same periods in 2008. The increase in operating margin and revenue was due to a planned outage to complete a major overhaul in the second quarter of 2008, partially offset by higher pricing in 2008 to offset the lower generation caused by the outage.

Generation during the three months ended June 30, 2009 was lower than in the same period in 2008 due to a temporary outage starting on April 23, 2009 initiated by the Partnership and the PPA counterparty due to reduced production from the plant’s major wood waste suppliers. The Partnership has identified other sources of supply, but these sources are more expensive. Considering the economics of the power produced at high fuel prices relative to the value of the electricity produced during a low electricity demand period in the region, the Partnership and the PPA counterparty agreed to the temporary outage. The Partnership expects the plant will remain offline until the fourth quarter of 2009, when the PPA counterparty anticipates it will have greater need for the power from the plant. Under the terms of the Williams Lake PPA, the Partnership will continue to receive energy payments while the plant is offline. Williams Lake expanded its wood waste storage capacity in July 2009, to provide flexibility in managing available wood waste supplies. Based on the anticipated impact of the increase in storage capacity, the operating margin provided by Williams Lake in 2009 is expected to be similar to 2008 levels.

Mamquam and Queen Charlotte

Operating margin at Mamquam and Queen Charlotte was \$4.4 million and \$5.9 million for the three and six months ended June 30, 2009, consistent with \$4.4 million and \$5.7 million for the same periods in 2008.

Northwest US Plants

Operating margin from Frederickson was \$3.2 million and \$6.4 million for the three and six months ended June 30, 2009 consistent with \$3.6 million and \$7.0 million for the same periods in 2008.

Operating margin from Manchief was \$6.0 million and \$11.3 million for the three and six months ended June 30, 2009, compared to \$4.9 million and \$10.0 million for the same periods in 2008.

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The increase in operating margin is the result of higher dispatch of the plant due to outages at plants in the region.

Operating margin from Greeley was \$0.1 million and \$0.5 million for the three and six months ended June 30, 2009 compared to an operating margin loss of \$0.1 million and operating margin of \$0.1 million for the same periods in 2008. The increases were due to lower prices for natural gas supply in 2009 compared to 2008.

California Plants

Operating margin from the Naval facilities was \$6.4 million and \$8.0 million for the three and six months ended June 30, 2009 compared to \$7.1 million and \$9.5 million for the same periods in 2008. The decrease was due to lower dispatch of Naval Station due to planned outages for inspections and maintenance in February 2009 and an unplanned outage in April 2009 partially offset by lower maintenance costs at North Island in 2009.

Operating margin from Oxnard was \$3.1 million and \$3.0 million for the three and six months ended June 30, 2009 consistent with \$2.6 million and \$3.2 million for the same periods in 2008. During the three months ended June 30, 2009 Oxnard completed a turbine repair related to damage to the natural gas turbine identified in 2008. The total cost of the repair was \$3.1 million, including lease engine costs. Insurance covered approximately 75% of the costs.

Curtis Palmer

Operating margin from Curtis Palmer was \$11.6 million and \$20.3 million for the three and six months ended June 30, 2009 compared to \$7.1 million and \$16.6 million for the same periods in 2008. The increases were due to a step-up in pricing under the PPA of 18% in December 2008 and higher generation due to higher water flows partially offset by a planned outage to complete an overhaul in June 2009.

Northeast US Natural Gas Plants

Operating margin from Morris, which was acquired on October 31, 2008, was \$3.5 million and \$5.9 million for the three and six months ended June 30, 2009, in line with expectations.

Operating margin from Kenilworth was \$1.2 million and \$2.7 million for the three and six months ended June 30, 2009 up from \$0.9 million and \$1.8 million for the same periods in 2008.

North Carolina Plants

The North Carolina plants reported operating margin losses of \$3.2 million and \$5.5 million for the three and six months ended June 30, 2009 compared to operating margin of \$0.4 million and \$1.1 million for the same periods in 2008. The decreases in operating margin, revenue and generation were due to lower dispatch during the period due to decreased power demand and increased competition from natural gas plants in the region.

The decrease in operating margin was also the result of higher maintenance costs for planned repairs as well as for a generator failure at Roxboro. The unit is expected to be back in service by September 1, 2009 and the impact of the outage on operating margin in the third quarter of 2009 is expected to be approximately \$2 million including anticipated insurance coverage. This outage as well as scheduled outages associated with the enhancement projects at the plants resulted in lower availability during the second quarter of 2009.

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Fair value changes

Unrealized gains on foreign exchange contracts were \$33.9 million and \$17.7 million for the three and six months ended June 30, 2009 compared to unrealized gains of \$5.9 million and unrealized losses of \$9.4 million reported for the same periods in 2008. The change in fair value was primarily due to changes in the forward prices for US dollars relative to Canadian dollars which decreased \$0.092 and \$0.038 for the three and six months ended June 30, 2009 compared to a decrease of \$0.027 and an increase of \$0.021 for the same periods in 2008.

The Partnership recorded fair value gains on natural gas supply contracts of \$1.3 million and losses of \$32.8 million for the three and six months ended June 30, 2009 compared to fair value gains of \$102.8 million and \$170.3 million for the same periods in 2008. The changes in the fair value of the natural gas contracts were primarily due to changes in natural gas forward prices. For the three months ended June 30, 2009, the fair value gains were the result of increases in forward natural gas prices in Colorado, partially offset by declines in forward natural gas prices in Alberta. Forward prices in Alberta were the primary cause of the changes in the other periods. Alberta forward natural gas prices decreased \$0.51 per gigajoule (GJ) for the six months ended June 30, 2009 compared to increases of \$1.85 and \$2.95 per GJ for the three and six months ended June 30, 2008.

COST OF FUEL	Three months ended		Six months ended	
		June 30		June 30
<i>(millions of dollars)(unaudited)</i>	2009	2008	2009	2008
Ontario plants				
Natural gas	16.9	17.4	34.7	34.1
Waste heat	1.0	4.4	2.5	4.9
Wood waste	1.1	0.9	1.9	1.5
	19.0	22.7	39.1	40.5
Williams Lake - wood waste	1.2	0.7	3.3	1.3
Northwest US plants - natural gas	2.9	2.9	6.0	6.0
California plants - natural gas	9.8	25.6	24.4	47.1
Northeast US natural gas plants ⁽¹⁾	13.6	5.2	34.3	11.4
North Carolina plants - coal, tire-derived fuel & wood waste	3.6	10.4	10.1	19.1
	50.1	67.5	117.2	125.4
Fair value changes on natural gas contracts	(1.3)	(102.8)	32.8	(170.3)
	48.8	(35.3)	150.0	(44.9)

⁽¹⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

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.

For the three and six months ended June 30, 2009, fuel costs, excluding fair value changes on natural gas contracts, were \$50.1 million and \$117.2 million compared to \$67.5 million and \$125.4 million for the same periods in 2008.

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Fuel costs at the Ontario plants for the three and six months ended June 30, 2009 were \$19.0 million and \$39.1 million compared to \$22.7 million and \$40.5 million for the same periods in 2008. The decreases were due to lower waste heat costs and lower natural gas prices, which reduced transportation costs and the cost of spot natural gas purchases, partially offset by contractual price increases.

Williams Lake incurred fuel costs of \$1.2 million and \$3.3 million for the three and six months ended June 30, 2009, compared to \$0.7 million and \$1.3 million for the same periods in 2008. The increase was due primarily to the use of higher priced wood waste due to reduced production from the plant’s major suppliers.

The Northwest US plants incurred fuel costs of \$2.9 million and \$6.0 million for the three and six months ended June 30, 2009, consistent with \$2.9 million and \$6.0 million for the same periods in 2008.

Fuel costs at the California facilities were \$9.8 million and \$24.4 million for the three and six months ended June 30, 2009 compared to \$25.6 million and \$47.1 million for the same periods in 2008. The decrease was due to lower natural gas prices and planned outages for inspections at Naval Station.

The Northeast US natural gas plants incurred fuel costs of \$13.6 million and \$34.3 million for the three and six months ended June 30, 2009, compared to \$5.2 million and \$11.4 million for the same periods in 2008. The increase was primarily due to the acquisition of Morris on October 31, 2008, which had fuel costs of \$7.3 million and \$19.8 million in the three and six months ended June 30, 2009.

The North Carolina plants incurred fuel costs of \$3.6 million and \$10.1 million for the three and six months ended June 30, 2009, compared to \$10.4 million and \$19.1 million for the same periods in 2008. The decrease was the result of lower generation.

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

OPERATING AND MAINTENANCE EXPENSE

<i>(millions of dollars)(unaudited)</i>	Three months ended		Six months ended	
	2009	June 30 2008	2009	June 30 2008
Ontario plants	3.8	3.8	7.6	7.7
Williams Lake	3.2	3.8	5.2	5.7
Mamquam and Queen Charlotte	1.1	1.2	2.1	2.4
Northwest US plants	4.2	2.8	7.9	5.9
California plants	5.4	6.0	11.1	11.3
Curtis Palmer	1.4	1.3	2.9	2.5
Northeast US natural gas plants ⁽¹⁾	3.1	0.7	6.0	1.3
North Carolina plants	6.2	4.2	12.5	7.7
PERC management expenses	0.3	0.3	0.6	0.5
	28.7	24.1	55.9	45.0

⁽¹⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

Operating and maintenance expenses include payments to the Manager and third parties for the operation and routine maintenance of the plants. Fees paid to the Manager are based on fixed charges adjusted annually for inflation for the Canadian plants, Curtis Palmer and Manchief, and a flow through of costs for the remaining US plants. Operating and maintenance expenses were \$28.7 million and \$55.9 million for the three and six months ended June 30, 2009, compared to \$24.1 million and \$45.0 million for the same periods in 2008. The increase was primarily due to the acquisition of Morris on October 31, 2008, which had operating and maintenance costs of \$2.4 million and \$4.5 million in the three and six months ended June 30, 2009, higher maintenance costs at the North Carolina plants for planned repairs as well as for a generator failure at Roxboro and a turbine repair at Frederickson in the second quarter of 2009.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the three and six months ended June 30, 2009 was \$23.3 million and \$47.1 million compared to \$21.7 million and \$43.8 million for the same periods in 2008. The increase was primarily due to the acquisition of Morris on October 31, 2008.

MANAGEMENT AND ADMINISTRATION

Management and administration costs, which include fees payable to EPCOR and general and administrative costs, were \$2.9 million and \$7.2 million for the three and six months ended June 30, 2009 compared to \$5.0 million and \$8.5 million for the same periods in 2008. The decreases were primarily due to lower incentive fees as a result of the distribution reduction on the incentive fee calculation for the six months ended June 30, 2009 and changes in the method of determining the incentive fees thereafter. The Partnership also paid lower enhancement fees as a result of lower enhancement profits.

FOREIGN EXCHANGE LOSSES (GAINS)

The Partnership reported net foreign exchange losses of \$0.1 million and \$0.6 million for the three and six months ended June 30, 2009 compared to foreign exchange gains of \$2.7 million and foreign exchange losses of \$10.5 million for the same periods in 2008. In the fourth quarter of 2008 the Partnership re-evaluated the functional currency of its US subsidiaries and determined it to be US dollars. Accordingly, gains and losses on translating the Partnership’s US operations into Canadian dollars are accumulated as a component of partners’ equity commencing in the fourth quarter of 2008. The foreign exchange gains recorded in the three months ended June 30, 2008 were primarily the result of a strengthening of the Canadian dollar of \$0.007 relative to the US dollar on the translation of US dollar-denominated debt. The foreign exchange losses recorded in the six months ended June 30, 2008 were primarily the result of a weakening of the Canadian dollar of \$0.028 relative to the US dollar.

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 the equity basis. For the three and six months ended June 30, 2009, the Partnership received dividends of \$0.3 million and \$0.7 million (\$0.4 million and \$0.9 million for the same periods in 2008) on its 14.2% preferred ownership interest and dividends of \$0.5 million and \$1.3 million (\$0.8 million and \$1.6 million for the same periods in 2008) from its common interest in PERH.

In September 2008, the Partnership and Primary Energy Recycling Corporation (PERC), which owns a majority interest in PERH, undertook a sales process for the possible sale of PERC and/or PERH. In June 2009, PERC in conjunction with the Partnership concluded that none of the offers received would provide adequate value.

PERH has suspended dividends on its common shares effective June 2009 and outlined plans to recapitalize the company, including the conversion of all of its preferred interests, including the Partnership’s preferred interest, into newly issued common interests. The Partnership and PERC remain committed to optimizing the business and refinancing a US\$135 million term loan in a PERH subsidiary that matures on August 24, 2009; however, there is no assurance that the refinancing will occur. In the event that PERH is unable to refinance or extend the term loan, a collateral agent will be entitled on behalf of the lenders to, among other things, sell PERH assets and apply the proceeds to repay the amounts outstanding under the term loan. In the event that the recapitalization is not implemented, PERH and PERC may pursue other alternatives, including the sale of core assets or non-consensual proceedings under creditor protection legislation.

The Partnership, PERC and PERH have agreed on various changes to the management agreement pursuant to which the Partnership provides management services to PERC and PERH to be made in connection with the recapitalization of PERH. The Partnership expects operating margins from the revised management agreement to remain unchanged.

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When cash provided by operating activities exceeds cash distributions and maintenance capital expenditures, the Partnership utilizes the difference to stabilize future quarterly cash distributions, to finance growth capital expenditures and to make debt repayments. When cash provided by operating activities are less than cash distributions and maintenance capital expenditures, the Partnership utilizes available cash balances and short-term financing to cover the shortfall. The ability of the Partnership to sustain current cash flow is subject to the Partnership finding cash accretive investments to replace expected future declines in cash flow as contracts expire.

<i>(millions of dollars)(unaudited)</i>	Three months ended		Six months ended	
	2009	June 30 2008	2009	June 30 2008
Cash distributions	23.7	33.9	57.7	67.9
Cash provided by operating activities of continuing operations	33.1	39.4	66.8	81.0
Net income from continuing operations	42.3	105.1	9.7	158.4
Dividends from PERH	0.5	0.8	1.3	1.6
Additions to property, plant and equipment	25.9	10.0	42.9	13.4
Excess of cash provided by operating activities of continuing operations over cash distributions	9.4	5.5	9.1	13.1
Excess (shortfall) of net income from continuing operations over cash distributions	18.6	71.2	(48.0)	90.5

Cash provided by operating activities of continuing operations exceeded cash distributions by \$9.4 million and \$9.1 million for the three and six months ended June 30, 2009. The Partnership also incurred capital expenditures of \$25.9 million and \$42.9 million during the three and six months ended June 30, 2009, which the Partnership financed with cash on hand and draws under its revolving credit facilities. The Partnership also received proceeds on the sale of Castleton of \$11.8 million during the three months ended June 30, 2009.

Net income is not necessarily comparable to cash distributions as net income includes items such as 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.

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 two revolving credit facilities, each of \$100.0 million expiring in September 2010 and October 2011 and a third revolving credit facility of \$125.0 million expiring in June 2011. The Partnership also has two demand facilities, of \$20.0 million and US\$20.0 million. 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, utilizing its \$1 billion shelf prospectus which expires in August 2010.

The second quarter 2009 cash distribution of \$0.44 per unit will be paid on July 30, 2009 to unitholders of record on June 30, 2009.

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Capital expenditures

Capital expenditures for the three and six months ended June 30, 2009 totalled \$25.9 million and \$42.9 million compared with \$10.0 million and \$13.4 million for the same periods in 2008. Capital spending included spending for the enhancement of the Southport and Roxboro coal plants and the upgrade of the LM5000 natural gas turbine at North Island with an LM6000 unit.

<i>(millions of dollars)(unaudited)</i>	Three months ended		Six months ended	
	2009	June 30 2008	2009	June 30 2008
Maintenance capital expenditures	8.0	8.8	12.1	11.7
North Carolina enhancement project	11.0	1.2	17.9	1.7
North Island turbine replacement project	6.9	-	12.9	-
	25.9	10.0	42.9	13.4

In line with previous expectations, the Partnership plans to invest an additional \$61 million (US\$53 million) in the remaining six months of 2009 for the enhancement of Southport and Roxboro to reduce environmental emissions and improve their economic performance, with a total expected cost for the projects of US\$80 million.

During the second quarter of 2009 the Partnership completed the repowering of the natural gas turbine at North Island to improve plant efficiency. Project costs incurred to date were \$17.6 million (US\$14.4 million) with an additional \$3.6 million (US\$3.1 million) investment expected in the remaining six months of 2009 for capital spares and costs associated with final inspections, which will be completed after the summer peak demand season in Southern California.

The Partnership plans to complete a similar repowering project at Oxnard in 2010, at a cost of approximately \$23 million (US\$20 million) to improve plant efficiency and financial performance.

The Partnership continues to pursue development opportunities including an internal development project at the Queen Charlotte Islands. In March 2009, the Partnership filed a proposal with the Public Service Company of Colorado to construct additional facilities at Manchief with an in-service timeline of 2014. These two projects total approximately 220MW and could require up to \$300 million of new investment.

Financing

The following table summarizes the long-term debt of the Partnership.

<i>(millions of dollars)(unaudited)</i>	June 30 2009	December 31 2008
Senior unsecured notes, due 2036	210.0	210.0
Senior unsecured notes (US\$415.0) due 2014 to 2019	479.0	505.5
Secured term loan, due 2010	2.0	2.6
Revolving credit facilities	119.9	86.7
	810.9	804.8

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In July 2009, the Partnership reached an agreement to extend one of its credit facilities expiring in June 2010 to June 2011 and increased the amount available from \$100 million to \$125 million.

The Partnership’s debt to total capitalization ratio as at June 30, 2009 increased to 54% from 51% at December 31, 2008 primarily due to drawings on its revolving credit facilities, the impact of a strengthening US dollar on US dollar-denominated borrowings and declines in fair value of foreign exchange and natural gas contracts. The debt to total capitalization ratio is calculated as follows:

$$\text{Debt to total capitalization ratio} = \frac{\text{Debt (short-term debt + long-term debt)}}{\text{Debt + preferred shares + partners' equity}}$$

Under the terms of its debt agreements, the Partnership must maintain a debt to capitalization ratio of not more than 65% at the end of each fiscal quarter. During the six months ended June 30, 2009, the Partnership drew \$37.6 million on its revolving credit facilities to fund the North Carolina and North Island capital projects. In addition, under the revolving credit facilities, in the event the Partnership is assigned a rating of less than BBB+ by Standard and Poors (S&P) and BBB(high) by DBRS Limited (DBRS), the Partnership also would be required to maintain a ratio of EBITDA (earnings before interest, income taxes, depreciation and amortization as defined in the credit facilities) to interest expense of not less than 2.5 to 1, measured quarterly. Although the Partnership is not required to meet the EBITDA to interest ratio, the ratio was 4.4 at as at June 30, 2009.

In the second quarter of 2009, DBRS lowered its outlook for the Partnership from stable to negative and reduced its stability rating from STA-2(high) to STA-2(low) as a result of increasing debt levels. At the same time, DBRS confirmed its BBB(high) credit rating. In April 2009, S&P lowered its outlook for the Partnership from stable to negative as a result of increasing debt levels. At the same time, S&P confirmed its BBB+ credit rating and SR-2 stability rating for the Partnership.

The BBB+ debt rating by S&P is the fourth highest rating out of 10 rating categories. The plus sign shows the relative standing within the major rating categories. DBRS’ BBB(high) rating designates the Partnership’s debt as being of satisfactory credit quality with the protection of interest and principal still substantial. The “BBB” rating is DBRS’ fourth highest of 10 categories. The high classification shows the relative standing within the major rating categories.

Having an investment grade credit rating impacts the Partnership’s ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

The stability ratings of SR-2 by S&P is the second highest rating of seven categories and indicates that the Partnership has a high level of distributable cash generation stability relative to other rated Canadian income funds. The STA-2 (low) stability rating by DBRS is the second highest of seven categories in their rating system for income fund stability. DBRS further subcategorizes each rating by the designation of “high”, “middle” and “low” to indicate where an entity falls within the rating category.

Financial market liquidity

The exposure of the Partnership to the ongoing volatility in the Canadian and US financial markets is substantially unchanged from December 31, 2008. For further information on our

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outlook, refer to the Partnership’s December 31, 2008 MD&A. In line with expectations, the Partnership has increased the amount drawn on its revolving credit facilities to finance the enhancement capital spending at North Island and the North Carolina plants. The Partnership has a sufficient liquidity position with revolving credit facilities of \$325 million and a demand credit facility of \$20 million with Canadian tier 1 banks. The Partnership also has a demand credit facility of US\$20.0 million with a US tier 1 bank. Principal repayments on the Partnership’s long-term debt facilities are as follows:

Year	Principal repayment <i>(millions of dollars)</i>
2009 (6 months)	0.6
2010	57.8
2011	63.5
2014	219.3
2017	173.1
2019	86.6
2036	210.0

The Partnership expects to borrow an additional US\$40 million to US\$50 million on the credit facilities to fund the completion of the North Carolina capital project in 2009.

Further, the Partnership intends to establish a Premium Distribution Reinvestment Program to foster its capacity for growth.

Uncertainty in global financial markets and, in particular, the Canadian and US financial markets may adversely affect the Partnership’s ability to arrange permanent long-term financing for large acquisitions or development opportunities.

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 June 30, 2009, \$526.5 million (US\$471.3 million) or approximately 94% of expected future cash flows were economically hedged for 2009 to 2015 at a weighted average exchange rate of \$1.12 to US \$1.00.

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TRANSACTIONS WITH RELATED PARTIES

<i>(millions of dollars)(unaudited)</i>	Three months ended		Six months ended	
	2009	June 30 2008	2009	June 30 2008
Transactions with EPCOR				
Revenue - Frederickson duct firing capacity fees	0.1	-	0.1	-
Cost of fuel - Greeley natural gas contract	0.9	-	1.5	-
Operating and maintenance expense	13.5	10.8	26.5	21.9
Management and administration				
Base fee	0.3	0.4	0.6	0.7
Incentive fee	(0.6)	0.6	-	1.2
Enhancement fee	0.1	1.2	0.1	1.4
General and administrative costs	1.8	1.5	3.8	2.8
	1.6	3.7	4.5	6.1
Transactions of discontinued operations				
Cost of fuel - Castleton natural gas demand charge	0.3	0.5	1.0	1.0
Operating and maintenance expense - Castleton	0.5	0.7	1.4	1.4
	0.8	1.2	2.4	2.4
Acquisition and divestiture fees	0.2	-	0.2	-
Transactions with PERH				
Revenue				
Base management fees	1.0	0.9	1.9	1.7

In operating the Partnership's 20 power plants, the Partnership and the Manager (EPCOR during the six months ended June 30, 2009) 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 six months ended June 30, 2009 and 2008. Operating and maintenance expenses were \$13.5 million and \$26.5 million for the three and six months ended June 30, 2009, an increase of \$2.7 million and \$4.6 million respectively from the same periods in 2008 due to the acquisition of Morris and the impact of a stronger US dollar on US operating and maintenance costs.

During the six months ended June 30, 2009, the Partnership made quarterly cash distributions to EPCOR in the amount proportionate to its ownership interest. At June 30, 2009, EPCOR owned 30.6% of the Partnership's units (June 30, 2008 – 30.6%).

CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

There were no material changes to the Partnership's purchase obligations, commitments or contingencies during the second quarter, including payments for the next five years and thereafter. For further information on these obligations, refer to the Partnership's December 31, 2008 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 obligations and fair value estimates. For further information on the Partnership’s critical accounting estimates, refer to the Partnership’s December 31, 2008 MD&A.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes made to the Partnership’s internal controls over financial reporting during the interim period ended June 30, 2009 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, 2008 as provided in the Partnership’s December 31, 2008 MD&A. Recent developments on risk are described below. For further information on business risks, refer to the Partnership’s December 31, 2008 MD&A.

Proposed emissions regulation

On May 15, 2009, Rep. Waxman and Rep. Markey introduced the American Clean Energy and Security Act in the Energy and Commerce Committee of the US House of Representatives (the Waxman-Markey Bill). The Waxman-Markey Bill would establish an economy wide cap and trade program; create incentives and standards for clean energy and energy efficiency; and establish green house gas emissions (GHG) standards for vehicles, stationary sources, and fuels. The provisions of the bill remain subject to extensive debate and it is unclear whether it will be passed, and if so, what revisions will be made in advance of passage.

On May 27, 2009, the Ontario Government proposed amendments to the Environmental Protection Act that will enable the government to establish a provincial GHG cap and trade system. The government has stated that it aims to harmonize its cap and trade program with Canadian federal, North American and international approaches and will continue to work with its partners in the Western Climate Initiative, which is playing an important role in the development of a U.S. federal and broader North American cap and trade system. However, the timing and specifics of such a GHG cap and trade system are not known at this time, although public consultation will occur into the fall of 2009 and final regulations may not be implemented until 2012.

The proposed Canadian federal regulatory framework known as “Turning the Corner”, to reduce GHG emissions and air pollution, recommended an 18% reduction in GHG emissions intensity starting in 2010 and increasing by 2% per year thereafter resulting in a 20% absolute reduction in GHG emissions from 2006 levels by 2020, and a 50% reduction in air pollution by 2015. Subsequently released government information indicates that some or all of these proposed compliance dates will be extended, starting in 2012 as opposed to 2010.

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The Partnership is assessing the potential impact of these initiatives, but at this time there is insufficient information to assess the full financial and operational implications on the Partnership's facilities. To the extent that additional regulation is passed, the Partnership could incur increased costs.

FUTURE ACCOUNTING STANDARDS

International financial reporting standards

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

The Partnership’s plan for conversion to and implementation of these international standards has not changed substantially since December 31, 2008. For further information on our plan for conversion and implementation, refer to the Partnership’s December 31, 2008 MD&A.

Fair value measurement disclosure

In June 2009, the CICA amended Handbook Section 3862 Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7 Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements, and about the liquidity risk of financial instruments. Although the amendments apply to financial statements relating to fiscal years ending after September 30, 2009, comparative information is not required in the first year of application. The impacts of these amendments will be assessed and the necessary additional disclosures will be implemented commencing with the annual financial statements for 2009.

Consolidated financial statements and non-controlling interests

In January 2009, the CICA issued Handbook Section 1601 – Consolidated Financial Statements and Section – 1602 Non-controlling Interests, which replace Section 1600 – Consolidated Financial Statements. Section 1601 establishes the standards for the preparation of consolidated financial statements while Section 1602 establishes the standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of International Auditing Standard 27 – Consolidated and Separate Financial Statements.

Sections 1601 and 1602 will apply to the Partnership’s interim and annual consolidated financial statements relating to periods commencing on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided Section 1582 – Business Combinations is also adopted at the same time. The impact of the new standards and the option to adopt them early will be assessed as part of our IFRS project.

Business combinations

In January 2009, the CICA issued Handbook Section 1582 – Business Combinations, which replaces Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. The section will apply on a prospective basis to the Partnership’s future business combinations for which the acquisition date is on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Sections 1601 –

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Consolidated Financial Statements and 1602 – Non-controlling Interests are also adopted at the same time. The impact of the new standard and the option to adopt it early will be assessed as part of the Partnership’s IFRS project.

OUTLOOK

The Partnership’s longer term outlook, including expectations regarding the impact on the Partnership from the economic downturn remains substantially unchanged since December 31, 2008 as provided in the Partnership’s December 31, 2008 MD&A. For further information on the Partnership’s outlook, refer to its December 31, 2008 MD&A. The Partnership continues to expect that annual 2009 cash provided by operating activities before working capital changes plus PERH dividends will be in line with 2008. The impact of lower expected dispatch at the North Carolina facilities on operating margin is expected to be partially offset by lower incentive fees and lower emission credit costs for the North Carolina facilities due to lower prices for the credits and lower dispatch. The temporary outage at Williams Lake (see Revenue – Williams Lake) and PERH’s suspension of its dividend were anticipated in determining expectations for 2009.

The decrease in power demand and low natural gas prices may negatively impact negotiations for the renewal of the PPA’s at the North Carolina facilities, which expire on December 31, 2009, and future cash flows from these facilities.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

<i>(unaudited)</i> <i>(millions of dollars except per unit amounts)</i>	2009			2008			2007	
	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	165.2	127.6	103.8	133.5	143.9	118.1	114.1	144.9
Operating margin ⁽¹⁾	87.7	(0.8)	(32.1)	(118.4)	155.1	106.8	81.5	18.7
Net income (loss) from continuing operations	42.3	(32.6)	(73.3)	(152.2)	105.1	53.3	45.3	(15.9)
Net income (loss)	42.8	(33.3)	(73.1)	(153.0)	104.9	53.4	45.3	(15.9)
Cash provided by operating activities of continuing operations	33.1	33.7	56.5	20.0	39.4	41.6	35.7	22.8
Capital expenditures	25.9	17.0	21.5	5.1	10.0	3.4	4.1	2.6
Cash distributions	23.7	34.0	33.9	34.0	33.9	34.0	34.0	33.9
Per unit statistics								
Net income (loss) from continuing operations	\$ 0.78	\$ (0.60)	\$ (1.36)	\$ (2.82)	\$ 1.95	\$ 0.99	\$ 0.84	\$ (0.29)
Cash provided by operating activities of continuing operations ⁽¹⁾	\$ 0.61	\$ 0.63	\$ 1.05	\$ 0.37	\$ 0.73	\$ 0.77	\$ 0.66	\$ 0.42
Cash distributions	\$ 0.44	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63	\$ 0.63

⁽¹⁾ The selected quarterly consolidated financial data has been prepared in accordance with GAAP except for operating margin and cash provided by operating activities of continuing operations 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 prior to the fourth quarter of 2008 and fair value changes in foreign exchange contracts and natural gas supply contracts.

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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 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 fourth quarter of 2008, the Partnership acquired Morris.

In the fourth quarter of 2008, the Partnership recorded a \$24.1 million asset impairment charge on its investment in the common shares of PERH. 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 third quarter of 2008 the Partnership recorded a \$3.4 million reduction in natural gas costs based on our updated estimate of the cost for natural gas supplied under contract.

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

The Partnership recorded gains on the change in the fair value of the natural gas supply contracts in the fourth quarter of 2007 and the first and second quarters of 2008 and the second quarter of 2009 and losses in the third quarter of 2007, the third and fourth quarters of 2008 and the first quarter of 2009.

Unrealized fair value changes on foreign exchange contracts resulted in gains in the second quarters of 2007, 2008 and 2009. Losses were recorded in the fourth quarter of 2007, in the first, third and fourth quarters of 2008 and in the first quarter of 2009.

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

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 include (i) the sustainability of distributions, including relative to a long-term payout ratio target of 75% of cash provided by operating activities less maintenance capital; (ii) planned capital upgrades at Southport and Roxboro of US\$80 million, (iii) planned capital upgrades at Oxnard of US\$20 million, (iv) expectations regarding the in-service timeline and the expected required new investment for additional facilities at Manchief and the development project at the Queen Charlotte Islands, (v) expectations regarding the Partnership’s cash provided by operating activities, dividends received from PERH, capital expenditures generally and working capital in 2009, (vi) expectations regarding the cash to be retained by the Partnership as a result of the distribution reduction and the expected uses of that cash, and (vii) expectations regarding the financing of the Partnership’s capital expenditures.

These statements are based on certain assumptions and analyses 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 counterparties to fuel supply and power purchase agreements will continue to perform their obligations under the agreements taking account of the matters described herein, (viii) the level of plant availability and dispatch, (ix) the performance of contractors and suppliers, (x) the renewal and terms of PPAs, (xi) the ability of the Partnership to successfully integrate and realize the benefits of its acquisitions, (xii) the ability of the Partnership to implement its strategic initiatives and whether such initiatives will yield the expected benefits, and (xiii) 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’s facilities, (vii) ongoing compliance by the Partnership with its current debt covenants, (viii) developments within the North American capital markets, (ix) the availability and cost of permanent long term financing in respect of acquisitions and investments, (x) unanticipated maintenance and other expenditures, (xi) the Partnership’s ability to successfully realize the benefits of acquisitions and investments, (xii) changes in regulatory and government decisions including changes to emission regulations, (xiii) waste heat availability and water flows, (xiv) changes in existing and proposed tax and other legislation in Canada and the US and including changes in the Canada-

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

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. Forward-looking statements are provided for the purpose of presenting information about management’s current expectations and plans relating to the future and readers are cautioned that such statements may not be appropriate for other purposes. Except as required by law, the Partnership disclaims any intention and assumes no obligation to update any forward-looking statement.

QUARTERLY UNIT TRADING INFORMATION

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

For the three and six months ended <i>(unaudited)</i>	Jun. 30 2009	Mar. 31 2009	Dec. 31 2008	Sep. 30 2008	Jun. 30 2008
Unit price					
High	16.21	\$18.98	\$20.65	\$23.50	\$24.70
Low	11.65	\$12.90	\$15.50	\$19.83	\$21.52
Close	15.25	\$13.80	\$17.72	\$20.32	\$22.41
Volume traded (millions)	9.2	3.3	5.1	3.6	4.5

As at July 28, 2009, the Partnership had 53.9 million units outstanding. The weighted average number of units outstanding for the three and six months ended June 30, 2009 was 53.9 million.

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.

EPCOR Power L.P.
CONSOLIDATED STATEMENTS OF INCOME

<i>(unaudited)</i>	Three months ended		Six months ended	
	2009	2008	2009	2008
(In millions of dollars except units and per unit amounts)				
Revenues	\$ 165.2	\$ 143.9	\$ 292.8	\$ 262.0
Cost of fuel	48.8	(35.3)	150.0	(44.9)
Operating and maintenance expense	28.7	24.1	55.9	45.0
	87.7	155.1	86.9	261.9
Other costs (income)				
Depreciation and amortization	23.3	21.7	47.1	43.8
Management and administration	2.9	5.0	7.2	8.5
Foreign exchange losses (gains)	0.1	(2.7)	0.6	10.5
Equity losses in PERH	0.6	0.4	2.3	2.1
Financial charges and other, net (Note 4)	10.5	9.1	21.4	18.2
	37.4	33.5	78.6	83.1
Net income from continuing operations before income tax and preferred share dividends	50.3	121.6	8.3	178.8
Income tax expense (recovery)	6.3	14.8	(4.7)	17.1
Net income from continuing operations before preferred share dividends	44.0	106.8	13.0	161.7
Preferred share dividends of a subsidiary company	1.7	1.7	3.3	3.3
Net income from continuing operations	42.3	105.1	9.7	158.4
Income (loss) from discontinued operations, net of income tax (Note 3)	0.5	(0.2)	(0.2)	(0.1)
Net income	\$ 42.8	\$ 104.9	\$ 9.5	\$ 158.3
Net income per unit from continuing operations	\$ 0.78	\$ 1.95	\$ 0.18	\$ 2.94
Net income (loss) per unit from discontinued operations	\$ 0.01	\$ (0.00)	\$ (0.00)	\$ (0.00)
Net income per unit	\$ 0.79	\$ 1.95	\$ 0.18	\$ 2.94
Weighted average units outstanding (millions)	53.9	53.9	53.9	53.9

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.
CONSOLIDATED STATEMENTS OF CASH FLOW

<i>(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2009	2008	2009	2008
(In millions of dollars)				
Operating activities				
Net income from continuing operations	\$ 42.3	\$ 105.1	\$ 9.7	\$ 158.4
Items not affecting cash:				
Depreciation and amortization	23.3	21.7	47.1	43.8
Future income tax expense (recovery)	6.6	13.5	(5.3)	14.5
Fair value changes on derivative instruments	(35.2)	(108.7)	15.1	(161.0)
Unrealized foreign exchange losses (gains)	0.4	(2.9)	0.3	10.3
Other	0.9	0.8	3.3	2.3
	38.3	29.5	70.2	68.3
Change in non-cash operating working capital	(5.2)	9.9	(3.4)	12.7
Cash provided by operating activities of continuing operations	33.1	39.4	66.8	81.0
Cash (used in) provided by operating activities of discontinued operations	(1.5)	1.0	(2.8)	2.3
Cash provided by operating activities	31.6	40.4	64.0	83.3
Investing activities				
Additions to property, plant and equipment	(25.9)	(10.0)	(42.9)	(13.4)
Change in non-cash working capital	1.6	4.4	(2.2)	3.6
Dividends from PERH	0.5	0.8	1.3	1.6
Cash used in investing activities of continuing operations	(23.8)	(4.8)	(43.8)	(8.2)
Cash provided by (used in) investing activities of discontinued operations	11.7	(0.3)	11.6	-
Cash used in investing activities	(12.1)	(5.1)	(32.2)	(8.2)
Financing activities				
Distributions paid	(34.0)	(34.0)	(67.9)	(67.9)
Net borrowings under credit facilities	8.7	-	37.6	-
Long-term debt repaid	-	-	(0.6)	(0.5)
Cash used in financing activities	(25.3)	(34.0)	(30.9)	(68.4)
Foreign exchange (losses) gains on cash held in a foreign currency	(0.8)	0.2	(0.8)	0.7
(Decrease) increase in cash and cash equivalents	(6.6)	1.5	0.1	7.4
Cash and cash equivalents, beginning of period	9.7	26.0	3.0	20.1
Cash and cash equivalents, end of period	\$ 3.1	\$ 27.5	\$ 3.1	\$ 27.5
Supplementary cash flow information				
Income taxes paid net of income taxes recovered	\$ 1.1	\$ 1.5	\$ 1.4	\$ 4.5
Interest paid net of interest received	\$ 7.1	\$ 6.1	\$ 22.4	\$ 18.6

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.
CONSOLIDATED BALANCE SHEETS

<i>(unaudited)</i>	June 30, 2009	December 31, 2008
(In millions of dollars)		
ASSETS		
Current assets		
Cash and cash equivalents	\$ 3.1	\$ 3.0
Accounts receivable	52.1	60.6
Inventories	19.8	23.2
Prepays and other	7.3	5.0
Derivative instruments assets (Note 5)	2.9	22.8
Future income taxes	2.2	2.3
Current assets of discontinued operations	-	2.3
	87.4	119.2
Property, plant and equipment	1,088.3	1,106.0
Power purchase arrangements	373.3	408.6
Long-term investments	14.8	19.2
Goodwill	52.2	55.1
Derivative instruments assets (Note 5)	17.8	27.1
Future income taxes	21.6	16.8
Other assets	42.6	45.2
Long-term assets of discontinued operations	-	12.0
	\$ 1,698.0	\$ 1,809.2
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	\$ 55.6	\$ 70.3
Distributions payable	23.7	33.9
Long-term debt due within one year	1.3	1.3
Derivative instruments liabilities (Note 5)	14.3	13.0
Current liabilities of discontinued operations	-	1.2
	94.9	119.7
Asset retirement obligations	28.9	28.6
Long-term debt	804.9	798.5
Derivative instruments liabilities (Note 5)	18.4	38.5
Contract liabilities	3.1	4.7
Future income taxes	62.1	60.7
Long-term liabilities of discontinued operations	-	4.2
Preferred shares issued by a subsidiary company	122.0	122.0
Partners' equity	563.7	632.3
Subsequent event (Note 7)		
	\$ 1,698.0	\$ 1,809.2

See accompanying notes to the consolidated financial statements.

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

<i>(unaudited)</i> (In millions of dollars)	Six months ended June 30	
	2009	2008
Partnership capital		
Balance, beginning of period	\$ 1,197.1	\$ 1,197.1
Issue of partnership units	-	-
Balance, end of period	\$ 1,197.1	\$ 1,197.1
Deficit		
Balance, beginning of period:		
As previously reported	\$ (500.1)	\$ (296.5)
Adjustment for changes in accounting policies (Note 2)	3.9	-
As restated	(496.2)	(296.5)
Net income	9.5	158.3
Cash distributions	(57.7)	(67.9)
Balance, end of period	\$ (544.4)	\$ (206.1)
Accumulated other comprehensive (loss) income		
Balance, beginning of period	\$ (64.7)	\$ 5.1
Other comprehensive loss	(24.3)	(1.9)
Balance, end of period	\$ (89.0)	\$ 3.2
Total of deficit and accumulated other comprehensive (loss) income	\$ (633.4)	\$ (202.9)
Partners' equity	\$ 563.7	\$ 994.2

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 June 30		Six months ended June 30	
	2009	2008	2009	2008
(In millions of dollars)				
Net income	\$ 42.8	\$ 104.9	\$ 9.5	\$ 158.3
Other comprehensive loss, net of income tax				
Losses on translating net assets of self-sustaining foreign operations ⁽¹⁾	(41.0)	-	(23.9)	-
Amortization of deferred gains on derivatives de-designated as cash flow hedges to income ⁽¹⁾	-	(1.0)	(0.4)	(1.9)
Comprehensive income (loss)	\$ 1.8	\$ 103.9	\$ (14.8)	\$ 156.4

⁽¹⁾ 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, 2008, except for the changes described in Note 2. These consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. These consolidated financial statements for the three and six months ended June 30, 2009 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 2008 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 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 the opinion of management of the Partnership's General Partner, 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

Credit risk and the fair value of financial assets and financial liabilities

On January 20, 2009 the Emerging Issues Committee of the Canadian Institute of Chartered Accountants (CICA) issued EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Effective January 1, 2009, the Partnership adopted the recommendations of EIC-173 and applied the recommendations retrospectively without restatement of prior periods. On January 1, 2009, the Partnership made the following adjustments to the balance sheet to adopt the recommendations of EIC-173:

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Notes to the Interim Consolidated Financial Statements
June 30, 2009
(Unaudited)

Balance sheet item (<i>millions of dollars</i>)	Increase (decrease)	Explanation
Derivative instruments assets	(1.5)	Impact to fair value of foreign exchange and natural gas contracts from incorporating credit risk of counterparties of the Partnership.
Derivative instruments liabilities	(6.3)	
Future income taxes liabilities - non-current	0.9	Tax impact from adoption of new standard.
Opening deficit	(3.9)	After tax impact to opening deficit resulting from adoption of new standard.

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 provisions of International Financial Reporting Standards (IFRS). The Partnership adopted these amendments January 1, 2009 which did not result in a material transition adjustment to the financial statements. The new accounting standard has been applied prospectively and the comparative financial statements have not been restated.

Future accounting changes

International financial reporting standards

In 2005, the CICA announced plans to converge Canadian GAAP with IFRS over a transition period from 2006 to 2011. The CICA indicated that Canadian entities will be required to begin reporting under IFRS effective the first quarter of 2011 including comparative figures. A high level IFRS implementation plan has been developed and an assessment of the financial statement impact of the accounting standard differences is currently in progress. Based on the analysis to date, the most significant differences for the Partnership are anticipated to be related to property, plant and equipment, leases, joint arrangements, financial instruments and hedges, 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, in time to ensure transactions are recorded in accordance with IFRS for comparative reporting purposes at the required implementation date.

Consolidated financial statements and non-controlling interests

In January 2009, the CICA issued Handbook Section 1601 – Consolidated Financial Statements and Section – 1602 Non-controlling Interests, which replace Section 1600 – Consolidated Financial Statements. Section 1601 establishes the standards for the preparation of consolidated financial statements while Section 1602 establishes the standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of IFRS IAS 27 – Consolidated and Separate Financial Statements.

Sections 1601 and 1602 will apply to the Partnership's interim and annual consolidated financial statements relating to periods commencing on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided Section 1582 – Business Combinations is also adopted at the same time. The impact of the new standards and the option to adopt them early will be assessed as part of the Partnership's IFRS project.

Business combinations

In January 2009, the CICA issued Handbook Section 1582 – Business Combinations, which replaces Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. The section will apply on a prospective basis to the Partnership's future business combinations for which the acquisition date is on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests are also adopted at the same time. The impact of the new standard and the option to adopt it early will be assessed as part of the Partnership's IFRS project.

Fair value measurement disclosure

In June 2009, the CICA amended Handbook Section 3862 Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7 Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements and about the liquidity risk of financial instruments. Although the amendments apply to financial statements relating to fiscal years ending after September 30, 2009, comparative information is not required in the first year of application. The impacts of these amendments will be assessed and the necessary additional disclosures will be implemented commencing with the annual financial statements for 2009.

Note 3. Discontinued operations

The Partnership completed the sale of its Castleton facility (Castleton) on May 26, 2009. The disposition of Castleton resulted in proceeds of \$12.0 million (US\$10.7 million) less transaction costs of \$0.2 million (US\$0.2 million) and a pre-tax accounting gain of \$2.4 million.

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Notes to the Interim Consolidated Financial Statements
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(Unaudited)

A summary of revenues and expenses of Castleton were as follows:

<i>(millions of dollars)</i>	Three months ended		Six months ended	
	2009	June 30 2008	2009	June 30 2008
Revenues	\$ 0.6	\$ 3.4	\$ 2.1	\$ 6.8
Expenses				
Cost of fuel	0.6	0.6	2.1	1.1
Operating and maintenance expense	0.8	1.0	2.1	2.0
Depreciation and amortization	-	1.5	-	3.1
Foreign exchange losses	-	0.2	-	0.1
(Loss) income from operations	(0.8)	0.1	(2.1)	0.5
Gain on sale of Castleton	2.4	-	2.4	-
Income before income tax	1.6	0.1	0.3	0.5
Income tax expense	1.1	0.3	0.5	0.6
Income (loss) from discontinued operations	\$ 0.5	\$ (0.2)	\$ (0.2)	\$ (0.1)

Note 4. Financial charges and other, net

<i>(millions of dollars)</i>	Three months ended		Six months ended	
	2009	June 30 2008	2009	June 30 2008
Interest on long-term debt	\$ 10.6	\$ 9.4	\$ 21.7	\$ 18.7
Interest on short-term debt	0.4	0.2	0.6	0.3
Dividend income from Class B preferred share interests in PERH	(0.3)	(0.4)	(0.7)	(0.9)
Other	(0.2)	(0.1)	(0.2)	0.1
	\$ 10.5	\$ 9.1	\$ 21.4	\$ 18.2

Note 5. Financial instruments

Derivative instruments

Derivative instruments are held to manage financial risk related to energy procurement and 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.

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Notes to the Interim Consolidated Financial Statements
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(Unaudited)

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

<i>(millions of dollars)</i>		June 30, 2009		
	Natural gas non-hedges	Foreign exchange non-hedges		Total
Derivative instruments assets:				
Current	\$ 0.2	\$ 2.7	\$	2.9
Non-current	9.8	8.0		17.8
Derivative instruments liabilities:				
Current	(6.3)	(8.0)		(14.3)
Non-current	(0.5)	(17.9)		(18.4)
	\$ 3.2	\$ (15.2)	\$	(12.0)
Net notional amounts:				
Gigajoules (GJs)(millions)	63			
US foreign exchange (US dollars in millions)		471.3		
Contract terms (years)	1.5 to 7.5	0.2 to 6.5		

<i>(millions of dollars)</i>		December 31, 2008		
	Natural gas non-hedges	Foreign exchange non-hedges		Total
Derivative instruments assets:				
Current	\$ 15.5	\$ 7.3	\$	22.8
Non-current	23.5	3.6		27.1
Derivative instruments liabilities:				
Current	(1.5)	(11.5)		(13.0)
Non-current	(0.6)	(37.9)		(38.5)
	\$ 36.9	\$ (38.5)	\$	(1.6)
Net notional amounts:				
Gigajoules (GJs)(millions)	69			
US foreign exchange (US dollars in millions)		456.9		
Contract terms (years)	0.1 to 8.0	0.2 to 6.0		

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 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, discount rates for time value, and volatility for all of the Partnership's

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financial instruments. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material. With respect to natural gas the Partnership has determined the market is active to the end of the contract terms, a change from its previous assessment that the market was active within five years. In changing its assessment the Partnership considered market activity and the short period of time that the contracts extend beyond five years.

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

<i>(millions of dollars)</i>	Income statement category	Three months ended		Six months ended	
		2009	June 30 2008	2009	June 30 2008
Foreign exchange non-hedges	Revenue	\$ 38.1	\$ 9.0	\$ 18.2	\$ (2.2)
Natural gas non-hedges	Cost of fuel	1.3	102.8	(32.8)	170.3
Foreign exchange non-hedges	Foreign exchange losses (gains)	0.1	(0.2)	(0.5)	0.2

Note 6. 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, Illinois, New Jersey, New York, North Carolina and Washington.

Geographic information

<i>(millions of dollars)</i>	Three months ended June 30 2009			Three months ended June 30 2008		
	Canada	US	Total	Canada	US	Total
Revenue	\$ 86.3	\$ 78.9	\$ 165.2	\$ 60.5	\$ 83.4	\$ 143.9

<i>(millions of dollars)</i>	Six months ended June 30 2009			Six months ended June 30 2008		
	Canada	US	Total	Canada	US	Total
Revenue	\$ 123.5	\$ 169.3	\$ 292.8	\$ 105.8	\$ 156.2	\$ 262.0

<i>(millions of dollars)</i>	As at June 30, 2009			As at December 31, 2008		
	Canada	US	Total	Canada	US	Total
Assets						
PP&E	\$ 546.9	\$ 541.4	\$ 1,088.3	\$ 559.3	\$ 546.7	\$ 1,106.0
PPAs	38.2	335.1	373.3	39.7	368.9	408.6
Other assets	-	42.6	42.6	-	45.2	45.2
Goodwill	-	52.2	52.2	-	55.1	55.1
Total assets	\$ 585.1	\$ 971.3	\$ 1,556.4	\$ 599.0	\$ 1,015.9	\$ 1,614.9

Note 7. Subsequent event

On July 9, 2009, as part of the transfer by EPCOR Utilities Inc. (EPCOR) of a 27.8% interest in its power generation business to Capital Power Corporation (collectively with its subsidiaries, CPC, unless otherwise indicated), (i) EPLP Investments Inc. (EPLP

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Investments) acquired 16,513,504 limited partnership units in the capital of the Partnership, representing 30.6% of the total outstanding units of the Partnership, and all of the common shares of EPCOR Power Services Ltd., the General Partner of the Partnership, and (ii) CPC acquired 100% ownership of the companies that provide management and operations services to the Partnership and its subsidiaries pursuant to management and operations agreements. EPCOR owns 51 voting, non-participating shares of EPLP Investments and CPC owns 49 voting, participating shares of EPLP Investments.

Note 8. 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 or contact:

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