



EPCOR
Power L.P.

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EPCOR Power L.P. Announces 2006 Second Quarter Results

Edmonton, Alberta – July 25, 2006 (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, 2006.

"I'm pleased to report the Partnership is executing on a number of initiatives that are expected to provide ongoing stable future cash flows", said Brian Vaasjo, President, EPCOR Power Services Ltd. "These initiatives include the expected closing on August 1st of the previously announced Frederickson power facility acquisition from the Partnership's sponsor, EPCOR Utilities Inc. The Partnership also successfully completed its first public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of \$210 million, which provides a fixed interest rate of 5.95% for a term of 30 years. This long-term debt replaces the Partnership's previous credit facility that would have matured in 2009 and provides interest rate certainty for a 30-year period while eliminating near term re-financing risk. Finally, the Partnership reached an agreement with the Ontario Electricity Financial Corporation ("OEFC") in the first quarter of 2006 that provides greater certainty around price escalations under the Ontario purchase price agreements. These initiatives align with the Partnership's goal of providing unitholders with long term stability and sustainable cash distributions".

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

Funds generated from operations were \$31.0 million or \$0.65 per unit and \$81.8 million or \$1.72 per unit for the three and six months ended June 30, 2006 compared with \$37.1 million or \$0.78 per unit and \$78.7 million or \$1.66 per unit for the same periods in 2005. ⁽¹⁾ The second quarter decrease in funds generated from operations is primarily due to the step-down in pricing under the Curtis Palmer Power Purchase Agreement and additional fuel supply costs including accruals for gas supply contract claims from NAL Resources Limited ("NAL") and Devon Canada Corporation ("Devon"). The year to date increase in funds generated from operations in total and on a per unit basis was primarily due to an agreement with the OEFC on a replacement for the Direct Customer Rate ("DCR") index that was discontinued in 2002, partially offset by the lower Curtis Palmer pricing and higher fuel supply costs at the Ontario plants. The OEFC settlement adjusts the amount owed to the Partnership under the power purchase agreements ("PPAs") for the Ontario plants for the period from 2002 through to the end of the respective PPAs. The retroactive portion of the settlement was received in the first quarter and positively impacted funds generated from operations and net income by \$8.5 million.

Net income was \$30.3 million or \$0.64 per unit and \$64.2 million or \$1.35 per unit for the three and six months ended June 30, 2006 compared to \$15.5 million or \$0.33 per unit and \$37.3 million or \$0.79 per unit for the same periods in 2005. The increase in net income for the three and six months ended June 30, 2006 was due to foreign exchange gains related to the

⁽¹⁾ Funds generated from operations is a non-GAAP financial measure that is defined in the interim report.

Partnership's U.S. dollar denominated debt, the OEFC agreement and unrealized fair value changes in foreign exchange forward contracts.

Cash distributions of \$29.9 million or \$0.63 per unit were declared for the second quarter of 2006, consistent with the same period in 2005. The Partnership utilizes funds generated from operations in excess of cash distributions to stabilize future quarterly cash distributions, to finance capital expenditures and to make discretionary debt repayments.

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>	2006	2005	2006	2005
Power Generated (GWh)	708	723	1,401	1,420
Weighted Average Plant Availability	87%	87%	92%	92%
Funds Generated from Operations ^(a)	31.0	37.1	81.8	78.7
Per unit	\$0.65	\$0.78	\$1.72	\$1.66
Net Income	30.3	15.5	64.2	37.3
Per unit	\$0.64	\$0.33	\$1.35	\$0.79
Cash Available for Distributions ^(a)	29.8	34.5	79.3	75.2
Per unit	\$0.63	\$0.73	\$1.67	\$1.59
Cash Distributions	29.9	29.9	59.8	59.8
Per unit	\$0.63	\$0.63	\$1.26	\$1.26
Capital Expenditures	1.2	2.6	2.0	3.1
Weighted Average Units Outstanding	47.4	47.4	47.4	47.4

a) Funds Generated from Operations, Funds Generated from Operations per unit, Cash Available for Distributions and Cash Available for Distributions per unit are non-GAAP financial measures that are defined in the interim report.

The June 30, 2006 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.epcorpowerlp.ca) and will be available at SEDAR (www.sedar.com).

EPCOR Power L.P.

Interim Report

June 30, 2006

Management's discussion and analysis

This management's discussion and analysis (MD&A), dated July 25, 2006 should be read in conjunction with the unaudited interim consolidated financial statements of EPCOR Power L.P. (the Partnership) for the three and six months ended June 30, 2006 and the audited consolidated financial statements and MD&A of EPCOR Power L.P. for the year ended December 31, 2005.

EPCOR Power Services Ltd., the General Partner of the Partnership, is an indirect wholly-owned subsidiary of EPCOR Utilities Inc. (collectively with its wholly owned subsidiaries "EPCOR") and has responsibility for management of the Partnership. The Audit Committee of the Board of Directors of the General Partner is to review and approve the interim MD&A of the Partnership in accordance with the Audit Committee's terms of reference. The Audit Committee has reviewed and approved the contents of this interim MD&A.

Forward-looking statements

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 and uncertainties, which could cause the Partnership's actual results and experience to be materially different than the anticipated results. Such risks and uncertainties include, but are not limited to, the ability of the Partnership to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, plant availability, waste heat availability and water flows, regulatory and government decisions, competitive factors in the power industry, the current economic conditions in North America and the performance of contractors and suppliers.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Except as required by law, the Partnership disclaims any intention and assumes no obligation to update any forward-looking statement even if new information becomes available, as a result of future events or for any other reason.

RESULTS OF OPERATIONS

The Partnership reported funds generated from operations of \$31.0 million or \$0.65 per unit and \$81.8 million or \$1.72 per unit for the three and six months ended June 30, 2006 compared with \$37.1 million or \$0.78 per unit and \$78.7 million or \$1.66 per unit for the same periods in 2005. Funds generated from operations is defined below under Non-GAAP measures. The second quarter decrease in funds generated from operations compared to the prior year period is primarily due to a step-down in pricing under the Curtis Palmer Power Purchase Agreement and additional fuel supply costs including accruals for gas supply contract claims from NAL Resources Limited ("NAL") and Devon Canada Corporation ("Devon"). The year to date increase in funds generated from operations in total and on a per unit basis was due to an agreement with the Ontario Electricity Financial Corporation ("OEFC"), partially offset by the lower Curtis Palmer pricing and higher fuel supply costs. The agreement with the OEFC was on a replacement for the Direct Customer Rate ("DCR") index that was discontinued in 2002. This settlement adjusts the amount

owed under the power purchase agreements (“PPAs”) for the Ontario plants for the period from 2002 through to the end of the respective PPAs. The retroactive portion of the settlement was received in the first quarter and positively impacted funds generated from operations and net income by \$8.5 million. The expected full year impact of the settlement relating to the current year, excluding any retroactive amounts, is approximately a \$3 million increase in net income and funds from operations.

Net income was positively impacted in the second quarter by foreign exchange gains of \$9.5 million primarily related to the Partnership’s U.S. dollar-denominated debt and \$5.2 million of unrealized fair value changes in forward foreign exchange contracts. In the first quarter of 2006, net income was also positively impacted by the OEFC settlement and higher water flows at the Curtis Palmer facility.

Operating Margin

<i>(millions of dollars)(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2006	2005	2006	2005
Ontario	13.5	16.3	45.7	38.2
Williams Lake	5.5	4.9	12.7	11.9
Mamquam and Queen Charlotte	4.5	5.1	6.8	7.8
Curtis Palmer	15.9	13.2	30.9	24.7
ManChief	6.2	5.1	11.0	9.6
Castleton	2.7	2.0	4.6	4.0
	48.3	46.6	111.7	96.2

Operating margin of \$48.3 million and \$111.7 million for the three and six months ended June 30, 2006 was \$1.7 million and \$15.5 million higher respectively than the same periods of 2005. Operating margin is defined below under Non-GAAP measures. The increase in operating margin for the three months ended June 30, 2006 compared to June 30, 2005 is due to positive fair value changes in forward foreign exchange contracts that are included in revenue which has been partially offset by a \$3.0 million increase in fuel charges. These charges include \$2.3 million that relates to the years 2002 – 2005. The year to date increase in operating margin compared to the comparable period in the prior year was primarily due to the settlement with the OEFC and an increase in revenues at the Curtis Palmer plant due to higher water flows.

Non-GAAP measures

The Partnership uses operating margin, funds generated from operations, funds generated from operations per unit, cash available for distributions and cash available for distributions per unit as performance measures with respect to the plants and the Partnership. These terms are not defined financial measures according to Canadian generally accepted accounting principles (“GAAP”), and they do not have standardized meanings prescribed by GAAP. Therefore, these measures may not be comparable to similar measures presented by other enterprises. There have been no changes in the composition of these measures as used by the Partnership in 2006 or 2005.

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

<i>(millions of dollars)(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2006	2005	2006	2005
Operating Margin	48.3	46.6	111.7	96.2
Deduct:				
Depreciation and amortization	16.4	16.5	33.4	33.0
Management and administration	2.1	2.2	4.1	4.0
Foreign exchange (gain)/loss	(9.5)	2.8	(8.8)	4.1
Financial charges and other	6.0	6.3	11.9	12.7
Net Income Before Income Tax	33.3	18.8	71.1	42.4

The Partnership uses funds generated from operations as a performance measure of the Partnership's ability, over the long term, to fund unitholder distributions, capital expenditures and debt repayment. A reconciliation of cash flow provided by operating activities to funds generated from operations is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2006	2005	2006	2005
Cash provided by operating activities	33.1	37.8	87.4	75.7
Increase/(decrease) in operating working capital	(2.1)	(0.7)	(5.6)	3.0
Funds generated from operations	31.0	37.1	81.8	78.7

Funds generated from operations per unit equals funds generated from operations divided by the weighted average number of units outstanding for the respective periods.

The Partnership uses cash available for distributions as a performance measure of the Partnership's ability over the long term to fund unitholder distributions. Cash available for distributions in excess of cash distributions is utilized by the Partnership to stabilize future quarterly cash distributions, to finance future capital expenditures and to make discretionary debt repayments. A reconciliation from cash provided by operating activities to cash available for distributions is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2006	2005	2006	2005
Cash provided by operating activities	33.1	37.8	87.4	75.7
Increase/(decrease) in operating working capital	(2.1)	(0.7)	(5.6)	3.0
Additions to property, plant and equipment	(1.2)	(2.6)	(2.0)	(3.1)
Long-term debt repaid	-	-	(0.5)	(0.4)
Cash available for distributions	29.8	34.5	79.3	75.2

Cash available for distributions per unit equals cash available for distributions divided by the weighted average number of units outstanding for the respective periods.

Issue of Medium Term Notes

On June 23, 2006, the Partnership completed its first public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of \$210.0 million. The notes have a coupon rate of 5.95 per cent and mature on June 23, 2036. The net proceeds of the offering were used to repay the Partnership's \$210.0 million term loan from a syndicate of banks. This replacement of long-term debt is expected to result in increased interest expense of approximately \$1.6 million per annum but locks in rate certainty and removes near term re-financing risk. In conjunction with the repayment of the credit facility, the Partnership recorded a non-recurring charge of \$0.5 million with respect to cancellation of the existing interest rate swap contract and the write-off of deferred debt issue costs.

These debt securities are rated A (low) by Dominion Bond Rating Services and A- by Standard & Poor's Rating Service.

The offering was made in Canada under the Partnership's previously filed shelf prospectus dated June 15, 2006.

NAL and Devon Claims

In July, 2004 NAL and Devon, (collectively the "Plaintiffs") commenced actions against the Partnership claiming that the gas supply contracts under which the Plaintiffs sell gas to the Partnership for its Tunis, Ontario power plant have been frustrated as of January 1, 2003. The frustration claims are premised on an

alleged inability to determine escalations in the commodity charge for gas under the agreements due to the Ontario government's decision to restructure the Ontario electricity market and the consequent interruption of the former Ontario Hydro's practice of annually determining a "Direct Customer Rate" (DCR). The Plaintiffs' additionally seek monetary damages based on referenced spot prices for natural gas deliveries.

In March 2006, the Partnership determined that price escalations respecting power sales from the Tunis plant would appropriately be premised upon a calculation termed DCR(new) as put forth by one of Ontario Hydro's successors, the OEFC and as posted on the OEFC website, with potential for adjustments and reconciliations as the DCR(new) is updated. One feature of the DCR(new) is "three year averaging" which has the effect of lengthening the time over which volatility in the electricity market impacts current prices. Utilizing the DCR(new) calculation, the Partnership accrued \$1.9 million for expected additional payments to gas suppliers including NAL and Devon. In the second quarter of 2006, the Partnership also accrued a further \$3.0 million for potential additional payments to gas suppliers based on the aforementioned ongoing and publicly available OEFC price escalation information but without the added feature of 3 year averaging, with a view to eliminating any ongoing basis for differences of opinion over the interpretation of the price escalation provisions in the gas supply agreements. Discussions toward settlement of the claims have taken place and are expected to continue. Management believes there was no frustration of the contracts and that any amounts claimed above the aforementioned accrued amounts are without merit.

De-designation of Hedging Relationships for Certain Foreign Exchange Contracts

The Partnership has a hedging program to manage its exposure to changes in foreign currency exchange rates that result from future anticipated U.S. dollar-denominated cash flows from its U.S. power plants. Up to April 1, 2006 the Partnership elected to apply hedge accounting to these foreign exchange contracts where accounting hedge criterion were met. On April 1, 2006 the Partnership voluntarily de-designated these hedging relationships for accounting purposes on all outstanding foreign exchange contracts. As a result, a net derivative financial instrument asset of \$12.0 million was recognized. As the hedged item is still considered highly probable to occur, the previously deferred unrealized gains on the hedging of U.S. dollar-denominated cash flows are deferred and carried forward for subsequent recognition in earnings as or when the hedged item occurs.

Changes in the fair value of these foreign exchange contracts from April 1, 2006 onward are recorded in the revenue of the U.S. plants. In the second quarter of 2006, unrealized fair value changes of these contracts and amortization of the deferred gain resulted in revenue recognition of \$5.2 million.

Frederickson Acquisition

On April 7, 2006 the Partnership announced an agreement to acquire from EPCOR a 100% interest in Frederickson Power L.P. ("FPLP") for an aggregate purchase price of US \$118 million, subject to certain closing adjustments. FPLP owns a 50.15% interest in the Frederickson power facility, a 249 megawatt ("MW") (nominal) single unit, natural gas-fired combined cycle generating facility located in Pierce County, Washington State, U.S.A. The acquisition has received regulatory approvals and is expected to close August 1, 2006. In addition, at the closing of the acquisition, EPCOR will grant to the Partnership an option to acquire a 49% interest in the development rights for a second generating unit adjacent to the Frederickson facility site for US \$4 million.

The acquisition will be financed out of cash on hand, available committed lines of credit and issued Subscription Receipts. The Partnership issued 2,460,000 Subscription Receipts at a price of \$33.35 per Subscription Receipt, representing aggregate proceeds of \$82 million. Each Subscription Receipt represents the right of the holder to receive one limited partnership unit of the Partnership upon closing of the acquisition. The holders of these units are also entitled to receive a special payment of \$0.63 per unit on the later of the third business day after closing of the Frederickson Power L.P. acquisition or July 28, 2006.

Revenues and Plant Output
(millions of dollars except GWh)
(unaudited)

Three months ended June 30

Six months ended June 30

	GWh	2006	GWh	2005	GWh	2006	GWh	2005
Ontario								
- Power ⁽²⁾	337	27.7	332	25.9	690	73.8	679	60.1
- Enhancements		2.9		3.7		6.6		6.6
- Gas diversions		2.5		3.3		3.8		4.4
		33.1		32.9		84.2		71.1
Williams Lake								
- Firm energy	112	8.8	113	8.2	241	18.2	241	17.4
- Excess energy	12	0.6	10	0.4	28	1.5	23	0.9
	124	9.4	123	8.6	269	19.7	264	18.3
Mamquam/Queen Charlotte ⁽³⁾	95	5.6	106	5.5	143	9.1	159	8.9
Curtis Palmer ⁽⁴⁾	112	17.4	95	14.9	226	33.8	178	28.1
Manchief	16	7.8	9	6.5	39	14.2	13	12.7
Castleton	24	7.7	58	3.9	34	11.3	127	7.7
	708	81.0	723	72.3	1,401	172.3	1,420	146.8

Weighted Average Plant Availability⁽¹⁾
(unaudited)

Three months ended June 30

Six months ended June 30

	2006	2005	2006	2005
Ontario Plants	98%	96%	99%	98%
Williams Lake ⁽⁵⁾	87%	87%	93%	94%
Mamquam/Queen Charlotte ⁽³⁾	87%	98%	79%	89%
Curtis Palmer ⁽⁴⁾	100%	97%	99%	99%
Manchief ⁽⁵⁾	74%	74%	87%	87%
Castleton	94%	87%	97%	93%
Weighted Average Total	87%	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. The weighted average total is based on plant capacity.

(2) Power revenues for the Ontario plants are higher due to the settlement on the DCR replacement index in 2006.

(3) The 50 MW Mamquam facility was unavailable for part of the first quarter of 2005 and 2006 due to planned and unplanned maintenance outages.

(4) Revenues for Curtis Palmer for the three and six months ended June 30, 2006 were higher than the same periods last year due to favourable water flows in 2006.

(5) The lower availability at Williams Lake and Manchief in the second quarter of 2005 and 2006 is due to the annual planned maintenance outages.

Revenues of \$81.0 million and \$172.3 million for the three and six months ended June 30, 2006 were \$8.7 million and \$25.5 million higher than the same periods in 2005. The increase for the three month period was primarily due to the unrealized changes in the fair value of foreign currency contracts, contract pricing increases and higher water flows at the Curtis Palmer facility. The increase for the six month period includes the settlement with the OEFC on the replacement index for the DCR as well as the items noted above for the three months ended June 30, 2006.

Revenues at the Ontario plants of \$33.1 million and \$84.2 million for the three and six months ended June 30, 2006 were \$0.2 million and \$13.1 million higher than the same periods in 2005 primarily due to OEFC settlement. Enhancement revenues reflect decisions by the Manager to voluntarily curtail power production in favour of selling the unused natural gas at prevailing market prices. This is normally done in off-peak hours when contracted power prices are lower. Gas diversions occur when the Partnership sells gas in excess of daily plant requirements in situations, other than voluntary curtailment, such as during planned and unplanned outages. Enhancement and diversion revenues for the three months ended June 30, 2006 were lower than the comparable period in 2005 due to lower natural gas prices.

Revenues at the Williams Lake plant consist of firm energy sales, cost recovery components and excess energy sales under the PPAs with British Columbia Hydro and Power Authority ("BC Hydro"). Firm energy revenues of \$8.8 million and \$18.2 million for the three and six months ended June 30, 2006 were \$0.6 million and \$0.8 million higher than the same periods in 2005 due partially to an increase in cost recoveries for higher fuel costs. Excess energy sales were \$0.2 million and \$0.6 million higher for the periods in 2006 due to an increase in generation and a higher market-based excess energy price in 2006 of \$52 per MWh compared with \$40 per MWh in 2005.

The Mamquam and Queen Charlotte plants reported revenues of \$5.6 million and \$9.1 million for the three and six months ended June 30, 2006 consistent with revenues of \$5.5 million and \$8.9 million for the same periods in the prior year.

Revenue at the Curtis Palmer plant was \$17.4 million and \$33.8 million for the three and six months ended June 30, 2006, compared with \$14.9 million and \$28.1 million for the same periods in 2005. Unrealized fair value changes in foreign currency contracts contributed \$3.0 million to the increase in second quarter revenue over the corresponding period in 2005. The remaining increase is due to higher water flows.

Revenues at the Manchief plant were \$7.8 million and \$14.2 million for the three and six months ended June 30, 2006 compared with \$6.5 million and \$12.7 million for the same periods in 2005. The increases of \$1.3 million and \$1.5 million for the respective periods of 2006 compared to the same periods in 2005 were due to higher dispatch at the plant and unrealized fair value changes in foreign currency contracts.

Revenues at the Castleton plant of \$7.7 million and \$11.3 million for the three and six months ended June 30, 2006, compared to \$3.9 million and \$7.7 million for the same periods in 2005. The increase is due to increased gas diversion revenue of \$3.5 million and unrealized fair value changes in foreign currency contracts of \$0.8 million compared to prior periods.

Cost of fuel

Fuel costs include commodity price and transportation costs. For the three and six months ended June 30, 2006 fuel costs were \$20.6 million and \$37.5 million compared with \$14.5 million and \$28.5 for the same periods in 2005. Fuel costs at the Castleton plant for the three and six months ended June 30, 2006 increased compared to the same periods in 2005 due to increased diversion activity. The increase in fuel costs also resulted from the \$4.9 million retroactive impact of the DCR index used in some of the Ontario gas supply contracts for the period from 2002 to the end of 2005 and accruals on certain gas supply contract claims. Contractual increases in other gas supply contracts for the Ontario plants also contributed to the increase.

The Curtis Palmer, Mamquam and Queen Charlotte hydroelectric plants do not have fuel costs. The power buyer under the Manchief PPA provides all the fuel requirements for that plant however the Partnership is obligated to pay for demand charges associated with the transportation of natural gas to the facility.

Operating and maintenance expense

Operating and maintenance expense is based on fixed fees, adjusted annually for inflation, payable to EPCOR for the operation and routine maintenance of the plants. Operating and maintenance expense was \$7.0 million and \$14.1 million for the three and six months ended June 30, 2006 compared to \$7.0 million and \$14.0 million for the same periods in 2005.

Other plant operating expenses

Other plant operating expenses, which include insurance, property taxes and major maintenance expenses, of \$5.1 million and \$9.0 million for the three and six months ended June 30, 2006 compared to \$4.2 million and \$8.1 million for the same periods in 2005. The increase is due to higher major maintenance at the Mamquam and Queen Charlotte facilities of \$0.7 million and \$0.6 million compared to the respective prior year periods.

Depreciation and amortization

Depreciation and amortization expense for the three and six months ended June 30, 2006 were \$16.4 million and \$33.4 million compared to \$16.5 million and \$33.0 million for the same periods in 2005.

Management and administration

Management and administration costs, which include fees payable to EPCOR and general and administrative costs, were at levels consistent with prior year periods.

Foreign exchange gain/loss

The Partnership reported a foreign exchange gain of \$9.5 million for the three months ended June 30, 2006, compared to \$2.8 million loss for the same period in 2005. Similarly, foreign exchange gains of \$8.8 million were reported for the six months ended June 30, 2006 compared to a loss of \$4.1 million reported for the same period in 2005. The foreign exchange gains and losses reported in 2006 and 2005 were primarily unrealized and related to the translation of the Partnership's U.S. dollar-denominated debt.

Financial charges and other

Financial charges and other expenses of \$6.0 million and \$11.9 million for the three and six months ended June 30, 2006 were \$0.3 million and \$0.8 million lower compared with the same periods in 2005 primarily due to short term interest income on higher cash balances in 2006 and a lower US dollar exchange rate on the US dollar debt interest payments. Financial charges of \$0.5 million were recorded on the termination of the interest rate swap and expensing of deferred debt issue costs on repayment of the \$210 million credit facility in the second quarter of 2006.

Income taxes

Income taxes relate to the taxes of the Partnership's U.S. subsidiaries and withholding taxes on distributions from the U.S. subsidiaries. The increase of \$1.8 million in income tax expense for the six months ended June 30, 2006 compared to the same period in 2005 was due primarily to increased income from the Partnership's Curtis Palmer facility.

LIQUIDITY AND CAPITAL RESOURCES

Cash distributions

Cash distributions of \$0.63 per unit were declared for each of the first and second quarters of 2006, consistent with the same periods in 2005. The Partnership utilizes cash available for distributions in excess of cash distributions to stabilize future quarterly cash distributions, to finance capital expenditures and to make discretionary debt repayments.

The second quarter 2006 cash distribution of \$0.63 per unit will be paid on July 28, 2006 to unitholders of record on June 30, 2006.

In conjunction with the second quarter cash distribution, Subscription Receipt holders are entitled to receive a special payment of \$0.63 per Subscription Receipt on the later of the third business day after closing of the Frederickson Power L.P acquisition or July 28, 2006.

Capital expenditures

Capital expenditures for the six months ended June 30, 2006 totaled \$2.0 million compared with \$3.1 million for the same period in 2005 and consisted of plant improvements.

FOREIGN EXCHANGE RISK MANAGEMENT

The Partnership manages the foreign exchange risk of its future anticipated U.S. dollar-denominated cash flows from its U.S. plants through the use of forward foreign exchange contracts for periods up to six years. As at June 30, 2006, \$181.1 million or approximately 81 per cent of expected future cash flows were hedged for 2006 to 2012 at a weighted average exchange rate of 1.18. The hedges include contracts to cover U.S. dollar exposure as a result of the Frederickson acquisition.

TRANSACTIONS WITH RELATED PARTIES

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2006	2005	2006	2005
Revenues ⁽¹⁾				
Castleton - capacity payments	-	3.7	-	7.4
Ontario - enhancement revenues	-	3.7	-	6.6
Ontario - gas diversion sales	-	3.3	-	4.4
Ontario - Calstock guarantee fee	-	0.8	-	1.7
	-	11.5	-	20.1
Cost of Fuel				
Ontario - gas fuel supply ⁽¹⁾	-	6.1	-	11.8
Ontario - gas transportation ⁽¹⁾	-	2.8	-	5.6
Ontario - waste heat ⁽¹⁾	-	0.2	-	0.3
Castleton - gas demand charge	0.6	0.6	1.1	1.2
	0.6	9.7	1.1	18.9
Operating and Maintenance Expense	7.0	7.0	14.1	14.0
Management and Administration				
Base fee	0.3	0.3	0.6	0.6
Incentive fee	0.5	0.5	1.0	1.0
Enhancement fee	0.2	0.5	0.6	0.8
	1.0	1.3	2.2	2.4

(1) These transactions were related party transactions only until September 1, 2005 at which time TransCanada sold its interest in the Partnership to EPCOR.

CONTRACTUAL OBLIGATIONS

There have been no material changes to the Partnership's purchase obligations, including payments for the next five years and thereafter, since December 31, 2005 other than the proposed Frederickson acquisition. For further information on these obligations, refer to the MD&A in the Partnership's 2005 Annual Report.

SIGNIFICANT 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 the accrued contingent liability on the NAL/Devon claims and depreciation expense. For further information on the Partnership's critical accounting estimates, refer to the MD&A in the Partnership's 2005 Annual Report.

BUSINESS RISKS

The Partnership's business and operational risks remain substantially unchanged since December 31, 2005. For further information on business risks, refer to the MD&A in the Partnership's 2005 Annual Report.

Calstock Fuel Supply

The Partnership currently procures its wood waste fuel from five suppliers for the Calstock plant. In June, a fire at the mill of one supplier resulted in this mill shutting down, at least temporarily. In July, another supplier announced the indefinite closing of its mills beginning in October, 2006. Combined these two suppliers represent approximately 40% of the Calstock fuel supply. Sufficient wood waste supply for the Calstock plant remains available for normal course operations for the balance of 2006. The Partnership is actively pursuing long-term replacements for this displaced supply with the expectation that it will be able to do so without significant financial or operational impact.

OUTLOOK

The short-term outlook for the Partnership's business remains substantially unchanged since December 31, 2005. Funds generated from operations per unit in 2006 are expected to decline relative to 2005 due to the October 2005 expiry of the Calstock guarantee fee of approximately \$2.5 million annually and a temporary step-down in pricing of approximately 33 per cent under the Curtis Palmer PPA which began in the first quarter of 2006. This impact is estimated to reduce funds generated from operations by approximately \$14 million in 2006 compared to 2005. The price changes at Curtis Palmer over the remainder of the contract are step increases with the first one at eighteen per cent currently estimated to take effect in 2009. A portion of these impacts have been offset by the retroactive settlement with the OEFC on the replacement DCR index. The acquisition of the Frederickson facility, which is expected to close August 1, 2006, is forecast to be modestly accretive to funds generated from operations on a per unit basis. On an annualized basis, the increase in funds generated from operations is anticipated to be approximately \$10 million. Results for the Partnership will vary based on a number of factors, including the operational performance of the plants, natural gas prices, the level of waste heat fuel at the Ontario plants provided by TransCanada's adjacent compressor stations and water flows at the hydro electric facilities. Maintenance capital spending is expected to be slightly lower in 2006 than it has averaged in 2004 and 2005.

Based on the Partnership's 2006 operating and capital plan and taking into consideration the above noted factors, management estimates that 2006 cash available for distributions will exceed recent annual cash distributions of \$2.52 per unit.

The long-term outlook for the Partnership continues to improve as a result of many recent initiatives. These initiatives include the expected acquisition of the Frederickson power facility and the recently completed first public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of \$210 million, which provides a fixed interest rate of 5.95% for a term of 30 years. This long-term debt replaces the Partnership's previous credit facility that would have matured in 2009 and provides interest rate certainty for a 30-year period while eliminating near term re-financing risk. Finally, the Partnership reached an agreement with the OEFC in the first quarter of 2006 that provides greater certainty around price escalations under the Ontario purchase price agreements. These initiatives align with the Partnership's goal of providing unitholders with long term stability and sustainable cash distributions.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

<i>(unaudited)</i> <i>(millions of dollars except per unit amounts)</i>	2006			2005			2004	
	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	81.0	91.3	81.5	67.4	72.3	74.5	69.1	63.3
Net Income	30.3	33.9	21.2	28.0	15.5	21.8	30.2	29.1
Funds Generated from Operations	31.0	50.6	42.9	35.7	37.1	41.6	36.9	32.1
Capital Expenditures	1.2	0.8	9.2	2.1	2.6	0.5	3.8	1.6
Cash Available for Distributions	29.8	49.3	33.7	33.2	34.5	40.7	33.1	30.5
Cash Distributions	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
Per Unit Statistics								
Net Income	\$0.64	\$0.72	\$0.45	\$0.59	\$0.33	\$0.46	\$0.64	\$0.61
Funds Generated from Operations	\$0.65	\$1.07	\$0.91	\$0.75	\$0.78	\$0.88	\$0.78	\$0.68
Cash Available for Distributions	\$0.63	\$1.04	\$0.71	\$0.70	\$0.73	\$0.86	\$0.70	\$0.64
Cash Distributions	\$0.63	\$0.63	\$0.63	\$0.63	\$0.63	\$0.63	\$0.63	\$0.63

Factors Impacting Quarterly Financial Results

Quarterly revenues, net income and funds generated from operations are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in U.S. dollar exchange rates, 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 on the Partnership's U.S. dollar-denominated long-term debt and fair value changes in forward foreign exchange contracts that are included in revenue. Revenues, net income and funds generated from operations 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 PPAs. Contributions from the Williams Lake plant are usually lower in the fourth quarter once the annual firm energy requirements are met and the plant is only producing lower-priced excess energy. Revenues and net income from the Partnership's hydroelectric plants 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:

The Partnership issued U.S. dollar-denominated debt in 2004. This resulted in unrealized foreign exchange gains in quarters three and four of 2004, quarter three of 2005 and quarter two of 2006. Losses were recorded in the first, second and fourth quarters of 2005 and the first quarter of 2006. The gains and losses are due to fluctuations in the U.S. dollar.

In the third quarter of 2004, the Partnership acquired the Mamquam and Queen Charlotte power facilities resulting in increased revenues, net income and funds generated from operations.

The fourth quarter of 2005 and the first and second quarters of 2006 had unseasonably high water flows at the Curtis Palmer hydroelectric facility. Enhancement and diversion revenues at the Ontario plants increased due to higher natural gas prices in the fourth quarter of 2005 and the first quarter of 2006.

The first quarter of 2006 the Partnership reached a settlement with the OEFC on a replacement for the DCR. The retroactive portion of the settlement was recorded in the quarter and increased revenues, net income, funds generated from operations and cash available for distributions.

In the second quarter of 2006, the Partnership de-designated all of the forward foreign exchange cash flow hedges existing at April 1, 2006. Unrealized fair value changes in these contracts and amortization of the deferred gain totaling \$5.2 million was recognized in revenue and net income in the quarter. A \$3.0 million

fuel charge was accrued in the quarter for the potential payments to gas suppliers which impacts net income, funds generated from operations and cash available for distributions.

QUARTERLY UNIT TRADING INFORMATION

The Partnership units trade on the Toronto Stock Exchange under the symbol EP.UN. and the Subscription Receipts trade under the symbol EP.R.

For the three months ended (<i>unaudited</i>)	Jun. 30 2006	Mar. 31 2006	Dec. 31 2005	Sep. 30 2005	Jun. 30 2005	Mar. 31 2005
Unit Price						
High	\$33.90	\$36.00	\$37.00	\$37.47	\$37.06	\$35.90
Low	\$30.30	\$33.05	\$29.41	\$34.75	\$33.15	\$31.60
Close	\$33.00	\$33.75	\$35.25	\$35.99	\$36.60	\$33.60
Volume traded (millions)	4.6	4.9	5.4	3.7	3.7	3.5

As at June 30, 2006, the Partnership had 47,421,982 units outstanding. The weighted average number of units outstanding for the three months ended June 30, 2006 was 47.4 million which is consistent with the same period in 2005. Effective April 28, 2006, the Partnership also had 2,460,000 Subscription Receipts outstanding, which will be exchanged for Partnership units upon closing of the pending Frederickson acquisition.

ADDITIONAL INFORMATION

Additional information relating to EPCOR Power L.P. including the Partnership's 2005 Annual Information Form (AIF) and continuous disclosure documents are available on SEDAR at www.sedar.com.

CONSOLIDATED STATEMENTS OF INCOME

	Three months ended June 30		Six months ended June 30	
<i>(unaudited)</i>				
<i>(millions of dollars except per unit amounts)</i>	2006	2005	2006	2005
Revenues	81.0	72.3	172.3	146.8
Cost of Fuel	20.6	14.5	37.5	28.5
Operating and Maintenance Expense	7.0	7.0	14.1	14.0
Other Plant Operating Expenses	5.1	4.2	9.0	8.1
	48.3	46.6	111.7	96.2
Other Costs				
Depreciation and amortization	16.4	16.5	33.4	33.0
Management and administration	2.1	2.2	4.1	4.0
Foreign exchange (gain)/loss	(9.5)	2.8	(8.8)	4.1
Financial charges and other	6.0	6.3	11.9	12.7
	15.0	27.8	40.6	53.8
Net Income Before Income Tax	33.3	18.8	71.1	42.4
Income Tax Expense	3.0	3.3	6.9	5.1
Net Income	30.3	15.5	64.2	37.3
Net Income Per Unit	\$0.64	\$0.33	\$1.35	\$0.79
Weighted Average Units Outstanding (millions)	47.4	47.4	47.4	47.4

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

<i>(unaudited)</i> <i>(millions of dollars except per unit amounts)</i>	Three months ended June 30		Six months ended June 30	
	2006	2005	2006	2005
Cash Generated from Operations				
Net income	30.3	15.5	64.2	37.3
Depreciation and amortization	16.4	16.5	33.4	33.0
Future income tax	1.9	0.7	4.4	1.4
Unrealized fair value changes in foreign exchange contracts	(5.2)	-	(5.0)	-
Unrealized foreign exchange (gain)/loss	(9.5)	3.1	(8.8)	4.2
Other	(2.9)	1.3	(6.4)	2.8
Funds generated from operations	31.0	37.1	81.8	78.7
Increase/(decrease) in operating working capital	2.1	0.7	5.6	(3.0)
Net cash provided by operating activities	33.1	37.8	87.4	75.7
Investing Activities				
Capital expenditures	(1.2)	(2.6)	(2.0)	(3.1)
Net cash used in investing activities	(1.2)	(2.6)	(2.0)	(3.1)
Financing Activities				
Distributions paid	(29.9)	(29.9)	(59.8)	(59.8)
Proceeds from medium term notes	210.0	-	210.0	-
Repayment of credit facility	(210.0)	-	(210.0)	-
Long Term Debt repaid	-	-	(0.5)	(0.4)
Net cash used in financing activities	(29.9)	(29.9)	(60.3)	(60.2)
Increase in Cash and Cash Equivalents	2.0	5.3	25.1	12.4
Cash and Cash Equivalents, Beginning of Period	55.3	27.3	32.2	20.2
Cash and Cash Equivalents, End of Period	57.3	32.6	57.3	32.6
Supplementary Cash Flow Information				
Income taxes paid	0.6	0.9	3.4	1.3
Interest paid	3.5	2.3	12.1	11.8

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

<i>(unaudited)</i> <i>(millions of dollars)</i>	June 30, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	57.3	32.2
Accounts receivable	31.2	46.4
Inventories	7.2	7.2
Prepays and other	5.5	4.3
Derivative financial instruments asset (Note 2)	5.4	-
	106.6	90.1
Plant, Property and Equipment	854.6	873.7
Power Purchase Arrangements	336.5	347.9
Derivative Financial Instruments Asset (Note 2)	12.0	-
Other Assets	8.9	4.6
	1,318.6	1,316.3
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable	32.3	42.2
Distributions payable	29.9	29.9
Long-term debt due within one year	1.0	0.9
Derivative financial instruments liability (Note 2)	0.2	0.3
	63.4	73.3
Asset Retirement Obligations	17.9	17.1
Long-Term Debt (Note 3)	426.4	435.8
Derivative Financial Instruments Liability (Note 2)	12.2	-
Future Income Taxes	6.7	2.5
Partners' Equity	792.0	787.6
Contingencies (Note 7)	1,318.6	1,316.3
CONSOLIDATED PARTNERS' EQUITY		
<i>Six months ended June 30 (unaudited)</i> <i>(millions of dollars)</i>	2006	2005
Partnership Capital, beginning of period	1,015.6	1,015.6
Issue of Partnership units	-	-
Partnership Capital, end of period	1,015.6	1,015.6
Accumulated Deficit, beginning of period	(228.0)	(195.0)
Net Income	64.2	37.3
Cash Distributions	(59.8)	(59.7)
Accumulated Deficit, end of period	(223.6)	(217.4)
Partners' Equity	792.0	798.2

See accompanying notes to the Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Significant Accounting Policies

The consolidated financial statements of the Partnership have been prepared by the management of the General Partner in accordance with Canadian generally accepted accounting principles. The accounting policies applied are consistent with those outlined in the Partnership's annual financial statements for the year ended December 31, 2005. 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, 2006 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 2005 Annual Report.

Quarterly revenues, net income and funds generated from operations are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in U.S. dollar exchange rates, 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 on the Partnership's U.S. dollar-denominated long-term debt and fair value changes in derivative financial instruments. Revenues, net income and funds generated from operations 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 agreements (PPAs). Revenues and net income from the Partnership's hydroelectric plants are generally higher in the spring months due to seasonally higher water flows.

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.

2. Financial Derivatives

The Partnership has a hedging program to manage its exposure to changes in foreign currency exchange rates that result from future anticipated U.S. dollar-denominated cash flows from its U.S. power plants. Up to April 1, 2006 the Partnership elected to apply hedge accounting to these foreign exchange contracts where accounting hedge criterion were met. On April 1, 2006 the Partnership voluntarily de-designated these hedging relationships for accounting purposes on all outstanding foreign exchange contracts. As a result a net derivative financial instrument asset of \$12.0 million was recognized which will be recorded into income in the same periods that the related previously hedged U.S. revenue occurs. As the hedged item is still considered highly probable to occur, the previously deferred unrealized gains on the hedging of U.S. dollar-denominated cash flows are deferred and carried forward for subsequent recognition in earnings as or when the hedged item occurs.

Changes in the fair value of these foreign exchange contracts from April 1, 2006 forward are recorded in the revenue of the U.S. plants. In the second quarter of 2006, unrealized fair value changes in these contracts and amortization of the deferred gain resulted in revenue recognition of \$5.2 million.

3. Long Term Debt

On June 23, 2006, the Partnership completed its first public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of \$210 million. The notes have a coupon rate of 5.95 per cent

payable semi annually in June and December and mature on June 23, 2036. The net proceeds of the offering were used to repay the Partnership's \$210 million credit facility.

4. Operating Leases

As at June 30, 2006, the carrying value of the Manchief, Mamquam and Queen Charlotte plant, property and equipment was \$233.1 million (June 30, 2005 – \$232.8 million) less accumulated depreciation of \$14.1 million (June 30, 2005 – \$7.2 million). The Partnership's revenues for the three and six months ended June 30, 2006 included \$13.4 million and \$23.3 million with respect to the Manchief, Mamquam and Queen Charlotte PPAs (\$12.0 million and \$21.6 million for the three and six months ended June 30, 2005).

5. United States Operations

For the three and six months ended June 30, 2006, the Partnership's U.S. operations generated approximately \$34.5 million and \$60.9 million of revenue (\$25.3 million and \$48.5 million for the three and six months ended June 30, 2005). As at June 30, 2006, the net book value of plant, property and equipment and PPAs was \$527.3 million (June 30, 2005 - \$570.1 million) related to assets held in the U.S.

6. Sale of Interest in the Partnership

On September 1, 2005, EPCOR Utilities Inc., collectively with its subsidiaries (EPCOR) completed its acquisition of TransCanada Corporation's (TransCanada) interest in TransCanada Power, L.P. (the Partnership). In connection with the close of the transaction, the Partnership was renamed EPCOR Power L.P. EPCOR's acquisition included: approximately 14.5 million units of the Partnership, representing approximately 30.6 per cent of the outstanding units; 100 per cent ownership of the General Partner of the Partnership; and management and operations agreements governing the ongoing operation of the Partnership's power generation assets.

7. Contingencies

In July, 2004 NAL and Devon, (collectively the "Plaintiffs") commenced actions against the Partnership claiming that the gas supply contracts under which the Plaintiffs' sell gas to the Partnership for its Tunis, Ontario power plant have been frustrated as of January 1, 2003. The frustration claims are premised on an alleged inability to determine escalations in the commodity charge for gas under the agreements due to the Ontario government's decision to restructure the Ontario electricity market and the consequent interruption of the former Ontario Hydro's practice of annually determining a "Direct Customer Rate" (DCR). The Plaintiffs' additionally seek monetary damages based on referenced spot prices for natural gas deliveries.

In March 2006, the Partnership determined that price escalations respecting power sales from the Tunis plant would appropriately be premised upon a calculation termed DCR(new) as put forth by one of Ontario Hydro's successors, the Ontario Electricity Financial Corporation (the "OEFC") and as posted on the OEFC website, with potential for adjustments and reconciliations as the DCR(new) is updated. One feature of the DCR(new) is "three year averaging" which has the effect of lengthening the time over which volatility in the electricity market impacts current prices. Utilizing the DCR(new) calculation, the Partnership accrued \$1.9 million for expected additional payments to gas suppliers including NAL and Devon. In the second quarter of 2006, the Partnership also accrued a further \$3.0 million for potential additional payments to gas suppliers based on the aforementioned ongoing and publicly available OEFC price escalation information but without the added feature of 3 year averaging, with a view to eliminating any ongoing basis for differences of opinion over the interpretation of the price escalation provisions in the gas supply agreements. Discussions toward settlement of the claims have taken place and are expected to continue. Management believes there was no frustration of the contracts and that any amounts claimed above the aforementioned accrued amounts are without merit.

8. Proposed Acquisition

On April 7, 2006 the Partnership announced an agreement to acquire from EPCOR a 100% interest in Frederickson Power L.P. ("FPLP") for an aggregate purchase price of US \$118 million, subject to certain closing adjustments. FPLP owns a 50.15% interest in the Frederickson power facility, a 249 megawatt ("MW") (nominal) single unit, natural gas-fired combined cycle generating facility located in Pierce County, Washington State, U.S.A. The acquisition has received regulatory approvals and is expected to close August 1, 2006. In addition, at the closing of the acquisition, EPCOR will grant to the Partnership an option to acquire a 49% interest in the development rights for a second generating unit adjacent to the Frederickson facility site for US \$4 million.

The acquisition will be financed out of cash on hand, available committed lines of credit and issued Subscription Receipts. The Partnership issued 2,460,000 Subscription Receipts at a price of \$33.35 per receipt, representing aggregate proceeds of \$82 million. Each Subscription Receipt represents the right of the holder to receive one limited partnership unit of the Partnership upon closing of the acquisition. In conjunction with the second quarter cash distribution, Subscription Receipt holders are entitled to receive a special payment of \$0.63 per Subscription Receipt on the later of the third business day after closing of the FPLP acquisition or July 28, 2006.

FPLP's portion (50.15%, or approximately 125 MW) of the Frederickson power facility's base 249 MW generating capacity has been sold under tolling arrangements in the form of power purchase agreements expiring in 2022 to three Washington State public utility districts. The remaining interest in the Frederickson power facility is held by Puget Sound Energy ("PSE") who uses its share of such capacity to serve its retail customers. EPCOR will continue to operate the Frederickson power facility.

9. Comparative Figures

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

For further information on the Partnership visit www.epcorpowlp.ca or contact:

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