MASIMO CORP
Form SC 13G/A
February 17, 2009

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

SCHEDULE 13G/A
(Rule 13d-102)

Amendment No. 1

INFORMATION TO BE INCLUDED IN STATEMENTS PURSUANT TO RULES 13d-1(b), (c) AND (d) AND AMENDMENTS THERETO FILED PURSUANT TO 13d-2 UNDER THE SECURITIES EXCHANGE ACT OF 1934

MASIMO CORPORATION
(Name of Issuer)

COMMON STOCK, PAR VALUE $0.001
(Title of Class of Securities)

574795100
(CUSIP Number)

December 31, 2008
(Date of Event Which Requires Filing of this Statement)

Check the appropriate box to designate the rule pursuant to which this Schedule is filed:

[ ] Rule 13d-1(b)

[X] Rule 13d-1(c)

[ ] Rule 13d-1(d)

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* The remainder of this cover page shall be filled out for a reporting person's initial filing on this form with respect to the subject class of securities, and for any subsequent amendment containing information which would alter the disclosures provided in a prior cover page.

The information required in the remainder of this cover page shall not be deemed to be "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934 (the "Act") or otherwise subject to the liabilities of that section of the Act but shall be subject to all other provisions of the Act (however, see the Notes).

(1)	NAME OF REPORTING PERSON S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON Davidson Kempner Partners		
(2)	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP (a) [ ] (b) [X]		
(3)	SEC USE ONLY		
(4)	CITIZENSHIP OR PLACE OF ORGANIZATION New York		
NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER	0
	(6)	SHARED VOTING POWER	0
	(7)	SOLE DISPOSITIVE POWER	0
	(8)	SHARED DISPOSITIVE POWER	0
(9)	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 0		
(10)	CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]		
(11)	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 0.0%		
(12)	TYPE OF REPORTING PERSON PN		

(1)	NAME OF REPORTING PERSON S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON Davidson Kempner Institutional Partners, L.P.
(2)	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP (a) [ ] (b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
Delaware

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER	0
	(6)	SHARED VOTING POWER	0
	(7)	SOLE DISPOSITIVE POWER	0
	(8)	SHARED DISPOSITIVE POWER	0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
PN

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
M. H. Davidson & Co.

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP
(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
New York

NUMBER OF SHARES	(5)	SOLE VOTING POWER	0

```
BENEFICIALLY    (6)      SHARED VOTING POWER
                                   0
OWNED BY        ----------------------------------------------------------------

EACH            (7)      SOLE DISPOSITIVE POWER
                                   0
REPORTING       ----------------------------------------------------------------

PERSON WITH     (8)      SHARED DISPOSITIVE POWER
                                   0
--------------------------------------------------------------------------------
       (9)    AGGREGATE AMOUNT BENEFICIALLY OWNED
              BY EACH REPORTING PERSON
                                   0
--------------------------------------------------------------------------------
       (10)   CHECK BOX IF THE AGGREGATE AMOUNT
              IN ROW (9) EXCLUDES CERTAIN SHARES                          [ ]
--------------------------------------------------------------------------------
       (11)   PERCENT OF CLASS REPRESENTED
              BY AMOUNT IN ROW (9)
                                   0.0%
------------------------------------------------------------------------------
       (12)   TYPE OF REPORTING PERSON
                                   PN
------------------------------------------------------------------------------
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--------------------------------------------------------------------------------
(1)      NAME OF REPORTING PERSON
         S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
         Davidson Kempner International, Ltd.
--------------------------------------------------------------------------------
(2)      CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

                                                          (a)  [ ]
                                                          (b)  [X]
--------------------------------------------------------------------------------
(3)      SEC USE ONLY
--------------------------------------------------------------------------------
(4)      CITIZENSHIP OR PLACE OF ORGANIZATION
                         British Virgin Islands
--------------------------------------------------------------------------------

NUMBER OF       (5)      SOLE VOTING POWER
                                   0
SHARES          ----------------------------------------------------------------

BENEFICIALLY    (6)      SHARED VOTING POWER
                                   0
OWNED BY        ----------------------------------------------------------------

EACH            (7)      SOLE DISPOSITIVE POWER
                                   0
REPORTING       ----------------------------------------------------------------
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PERSON WITH	(8)	SHARED DISPOSITIVE POWER 0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED
BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT
IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED
BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
CO

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Serena Limited

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
Cayman Islands

NUMBER OF	(5)	SOLE VOTING POWER 0
SHARES		
BENEFICIALLY	(6)	SHARED VOTING POWER 0
OWNED BY		
EACH	(7)	SOLE DISPOSITIVE POWER 0
REPORTING		
PERSON WITH	(8)	SHARED DISPOSITIVE POWER 0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED
BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT
IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

---

(11) PERCENT OF CLASS REPRESENTED
BY AMOUNT IN ROW (9)
0.0%

---

(12) TYPE OF REPORTING PERSON
CO

---

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Davidson Kempner Healthcare Fund LP

---

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

---

(3) SEC USE ONLY

---

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
Delaware

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

---

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED
BY EACH REPORTING PERSON
0

---

(10) CHECK BOX IF THE AGGREGATE AMOUNT
IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

---

(11) PERCENT OF CLASS REPRESENTED
BY AMOUNT IN ROW (9)
0.0%

---

(12) TYPE OF REPORTING PERSON
PN

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(1)	NAME OF REPORTING PERSON S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON Davidson Kempner Healthcare International Ltd.	
(2)	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP	(a) [ ] (b) [X]
(3)	SEC USE ONLY	
(4)	CITIZENSHIP OR PLACE OF ORGANIZATION Cayman Islands	

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5) SOLE VOTING POWER	0
	(6) SHARED VOTING POWER	0
	(7) SOLE DISPOSITIVE POWER	0
	(8) SHARED DISPOSITIVE POWER	0

(9)	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 0	
(10)	CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES	[ ]
(11)	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 0.0%	
(12)	TYPE OF REPORTING PERSON CO	

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(1) NAME OF REPORTING PERSON

S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
MHD Management Co.

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(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

---

(3) SEC USE ONLY

---

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
New York

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

---

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED
BY EACH REPORTING PERSON
0

---

(10) CHECK BOX IF THE AGGREGATE AMOUNT
IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

---

(11) PERCENT OF CLASS REPRESENTED
BY AMOUNT IN ROW (9)
0.0%

---

(12) TYPE OF REPORTING PERSON
PN

---

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Davidson Kempner Advisers Inc.

---

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

---

(3) SEC USE ONLY

(4)	CITIZENSHIP OR PLACE OF ORGANIZATION New York	
NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0
(9)	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 0	
(10)	CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES	[ ]
(11)	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 0.0%	
(12)	TYPE OF REPORTING PERSON IA	

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(1)	NAME OF REPORTING PERSON S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON Davidson Kempner International Advisors, L.L.C.	
(2)	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP	(a) [ ] (b) [X]
(3)	SEC USE ONLY	
(4)	CITIZENSHIP OR PLACE OF ORGANIZATION Delaware	
NUMBER OF SHARES	(5)	SOLE VOTING POWER 0

```
BENEFICIALLY    (6)      SHARED VOTING POWER
                                   0
OWNED BY        -----------------------------------------------------------------

EACH            (7)      SOLE DISPOSITIVE POWER
                                   0
REPORTING       -----------------------------------------------------------------

PERSON WITH     (8)      SHARED DISPOSITIVE POWER
                                   0
---------------------------------------------------------------------------------
       (9)   AGGREGATE AMOUNT BENEFICIALLY OWNED
             BY EACH REPORTING PERSON
                                   0
---------------------------------------------------------------------------------
       (10)  CHECK BOX IF THE AGGREGATE AMOUNT
             IN ROW (9) EXCLUDES CERTAIN SHARES                          [ ]
---------------------------------------------------------------------------------
       (11)  PERCENT OF CLASS REPRESENTED
             BY AMOUNT IN ROW (9)
                                   0.0%
-------------------------------------------------------------------------------
       (12)  TYPE OF REPORTING PERSON
                                   OO
-------------------------------------------------------------------------------
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---------------------------------------------------------------------------------
(1)      NAME OF REPORTING PERSON
         S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
         DK Group LLC
---------------------------------------------------------------------------------
(2)      CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

                                                          (a)  [ ]
                                                          (b)  [X]
---------------------------------------------------------------------------------
(3)      SEC USE ONLY
---------------------------------------------------------------------------------
(4)      CITIZENSHIP OR PLACE OF ORGANIZATION
                         Delaware
---------------------------------------------------------------------------------

NUMBER OF       (5)      SOLE VOTING POWER
                                   0
SHARES          -----------------------------------------------------------------

BENEFICIALLY    (6)      SHARED VOTING POWER
                                   0
OWNED BY        -----------------------------------------------------------------

EACH            (7)      SOLE DISPOSITIVE POWER
                                   0
REPORTING       -----------------------------------------------------------------

PERSON WITH     (8)      SHARED DISPOSITIVE POWER
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0

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(9) AGGREGATE AMOUNT BENEFICIALLY OWNED
BY EACH REPORTING PERSON
0

---

(10) CHECK BOX IF THE AGGREGATE AMOUNT
IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

---

(11) PERCENT OF CLASS REPRESENTED
BY AMOUNT IN ROW (9)
0.0%

---

(12) TYPE OF REPORTING PERSON
OO

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---

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
DK Management Partners LP

---

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

---

(3) SEC USE ONLY

---

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
Delaware

NUMBER OF SHARES	(5)	SOLE VOTING POWER 0
BENEFICIALLY OWNED BY	(6)	SHARED VOTING POWER 0
EACH REPORTING	(7)	SOLE DISPOSITIVE POWER 0
PERSON WITH	(8)	SHARED DISPOSITIVE POWER 0

---

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED
BY EACH REPORTING PERSON
0

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(10) CHECK BOX IF THE AGGREGATE AMOUNT
IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

```
       (11)  PERCENT OF CLASS REPRESENTED
             BY AMOUNT IN ROW (9)
                                 0.0%
------------------------------------------------------------------------------
       (12)  TYPE OF REPORTING PERSON
                                 PN
------------------------------------------------------------------------------
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--------------------------------------------------------------------------------
(1)      NAME OF REPORTING PERSON
         S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
         DK Stillwater GP LLC
--------------------------------------------------------------------------------
(2)      CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

                                                          (a)  [ ]
                                                          (b)  [X]
--------------------------------------------------------------------------------
(3)      SEC USE ONLY
--------------------------------------------------------------------------------
(4)      CITIZENSHIP OR PLACE OF ORGANIZATION
                         Delaware
--------------------------------------------------------------------------------

NUMBER OF        (5)      SOLE VOTING POWER
                                    0
SHARES           ---------------------------------------------------------------

BENEFICIALLY     (6)      SHARED VOTING POWER
                                    0
OWNED BY         ---------------------------------------------------------------

EACH             (7)      SOLE DISPOSITIVE POWER
                                    0
REPORTING        ---------------------------------------------------------------

PERSON WITH      (8)      SHARED DISPOSITIVE POWER
                                    0
--------------------------------------------------------------------------------
       (9)   AGGREGATE AMOUNT BENEFICIALLY OWNED
             BY EACH REPORTING PERSON
                                 0
--------------------------------------------------------------------------------
       (10)  CHECK BOX IF THE AGGREGATE AMOUNT
             IN ROW (9) EXCLUDES CERTAIN SHARES                          [ ]
--------------------------------------------------------------------------------
       (11)  PERCENT OF CLASS REPRESENTED
             BY AMOUNT IN ROW (9)
                                 0.0%
------------------------------------------------------------------------------
       (12)  TYPE OF REPORTING PERSON
                                 OO
------------------------------------------------------------------------------
```

(1)	NAME OF REPORTING PERSON S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON Thomas L. Kempner Jr.	
(2)	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP	(a) [ ] (b) [X]
(3)	SEC USE ONLY	
(4)	CITIZENSHIP OR PLACE OF ORGANIZATION United States	

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

(9)	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 0	
(10)	CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES	[ ]
(11)	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 0.0%	
(12)	TYPE OF REPORTING PERSON IN	

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON

Marvin H. Davidson

---

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

---

(3) SEC USE ONLY

---

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
United States

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

---

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON
0

---

(10) CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

---

(11) PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9)
0.0%

---

(12) TYPE OF REPORTING PERSON
IN

---

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Stephen M. Dowicz

---

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

---

(3) SEC USE ONLY

---

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
United States

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
IN

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Scott E. Davidson

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
United States

NUMBER OF SHARES BENEFICIALLY	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER

```
                                   0
OWNED BY        -----------------------------------------------------------------

EACH            (7)      SOLE DISPOSITIVE POWER
                                   0
REPORTING       -----------------------------------------------------------------

PERSON WITH     (8)      SHARED DISPOSITIVE POWER
                                   0
---------------------------------------------------------------------------------
       (9)    AGGREGATE AMOUNT BENEFICIALLY OWNED
              BY EACH REPORTING PERSON
                                   0
---------------------------------------------------------------------------------
       (10)   CHECK BOX IF THE AGGREGATE AMOUNT
              IN ROW (9) EXCLUDES CERTAIN SHARES                         [ ]
---------------------------------------------------------------------------------
       (11)   PERCENT OF CLASS REPRESENTED
              BY AMOUNT IN ROW (9)
                                   0.0%
-------------------------------------------------------------------------------
       (12)   TYPE OF REPORTING PERSON
                                   IN
-------------------------------------------------------------------------------
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---------------------------------------------------------------------------------
(1)      NAME OF REPORTING PERSON
         S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
         Michael J. Leffell
---------------------------------------------------------------------------------
(2)      CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

                                                          (a)  [ ]
                                                          (b)  [X]
---------------------------------------------------------------------------------
(3)      SEC USE ONLY
---------------------------------------------------------------------------------
(4)      CITIZENSHIP OR PLACE OF ORGANIZATION
                         United States
---------------------------------------------------------------------------------

NUMBER OF       (5)      SOLE VOTING POWER
                                   0
SHARES          -----------------------------------------------------------------

BENEFICIALLY    (6)      SHARED VOTING POWER
                                   0
OWNED BY        -----------------------------------------------------------------

EACH            (7)      SOLE DISPOSITIVE POWER
                                   0
REPORTING       -----------------------------------------------------------------

PERSON WITH     (8)      SHARED DISPOSITIVE POWER
                                   0
```

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
IN

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(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Timothy I. Levart

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
United Kingdom & United States

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED

BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
IN

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Robert J. Brivio, Jr.

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
United States

NUMBER OF SHARES	(5)	SOLE VOTING POWER 0
BENEFICIALLY OWNED BY	(6)	SHARED VOTING POWER 0
EACH REPORTING	(7)	SOLE DISPOSITIVE POWER 0
PERSON WITH	(8)	SHARED DISPOSITIVE POWER 0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED
BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT
IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED
BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
IN

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(1)	NAME OF REPORTING PERSON S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON Eric P. Epstein	
(2)	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP	(a) [ ] (b) [X]
(3)	SEC USE ONLY	
(4)	CITIZENSHIP OR PLACE OF ORGANIZATION United States	

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

(9)	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 0	
(10)	CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES	[ ]
(11)	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 0.0%	
(12)	TYPE OF REPORTING PERSON IN	

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(1)	NAME OF REPORTING PERSON S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON Anthony A. Yoseloff

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
United States

NUMBER OF SHARES	(5)	SOLE VOTING POWER 0
BENEFICIALLY OWNED BY	(6)	SHARED VOTING POWER 0
EACH REPORTING	(7)	SOLE DISPOSITIVE POWER 0
PERSON WITH	(8)	SHARED DISPOSITIVE POWER 0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
IN

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Avram Z. Friedman

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION

United States

NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0
	(7)	SOLE DISPOSITIVE POWER 0
	(8)	SHARED DISPOSITIVE POWER 0

(9) AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON
0

(10) CHECK BOX IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES [ ]

(11) PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9)
0.0%

(12) TYPE OF REPORTING PERSON
IN

Schedule 13G/A
CUSIP No. 574795100 Page 25 of 44

(1) NAME OF REPORTING PERSON
S.S. OR I.R.S. IDENTIFICATION NO. OF ABOVE PERSON
Conor Bastable

(2) CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP

(a) [ ]
(b) [X]

(3) SEC USE ONLY

(4) CITIZENSHIP OR PLACE OF ORGANIZATION
United States

NUMBER OF SHARES BENEFICIALLY	(5)	SOLE VOTING POWER 0
	(6)	SHARED VOTING POWER 0

```
OWNED BY        ----------------------------------------------------------------

EACH            (7)      SOLE DISPOSITIVE POWER
                                   0
REPORTING       ----------------------------------------------------------------

PERSON WITH     (8)      SHARED DISPOSITIVE POWER
                                   0
--------------------------------------------------------------------------------
       (9)   AGGREGATE AMOUNT BENEFICIALLY OWNED
             BY EACH REPORTING PERSON
                                   0
--------------------------------------------------------------------------------
       (10)  CHECK BOX IF THE AGGREGATE AMOUNT
             IN ROW (9) EXCLUDES CERTAIN SHARES                          [ ]
--------------------------------------------------------------------------------
       (11)  PERCENT OF CLASS REPRESENTED
             BY AMOUNT IN ROW (9)
                                   0.0%
------------------------------------------------------------------------------
       (12)  TYPE OF REPORTING PERSON
                                   IN
------------------------------------------------------------------------------
```


ITEM 1(a). NAME OF ISSUER:

Masimo Corporation (the "Company")

ITEM 1(b). ADDRESS OF ISSUER'S PRINCIPAL EXECUTIVE OFFICES:

40 Parker
Irvine, California 92618

ITEM 2(a). NAME OF PERSON FILING:

This Statement is filed by each of the entities and persons listed below, all of whom together are referred to herein as the "Reporting Persons":

(i) Davidson Kempner Partners, a New York limited partnership ("DKP");

(ii) Davidson Kempner Institutional Partners, L.P., a Delaware limited partnership ("DKIP");

(iii) M. H. Davidson & Co., a New York limited partnership ("CO");

(iv) Davidson Kempner International, Ltd., a British Virgin Islands corporation ("DKIL");

(v) Serena Limited, a Cayman Islands corporation ("Serena");

(vi) Davidson Kempner Healthcare Fund LP, a Delaware limited partnership ("DKHF");

(vii) Davidson Kempner Healthcare International Ltd., a Cayman Islands corporation ("DKHI");

(viii) MHD Management Co., a New York limited partnership and the general partner of DKP ("MHD");

(ix) Davidson Kempner Advisers Inc., a New York corporation and the general partner of DKIP ("DKAI"), which is registered as an investment adviser with the U.S. Securities and Exchange Commission;

(x) Davidson Kempner International Advisors, L.L.C., a Delaware limited liability company and the manager of DKIL and Serena ("DKIA");

(xi) DK Group LLC, a Delaware limited liability company and the general partner of DKHF ("DKG");

(xii) DK Management Partners LP, a Delaware limited partnership and the investment manager of DKHI ("DKMP");

(xiii) DK Stillwater GP LLC, a Delaware limited liability company and the general partner of DKMP ("DKS"); and

(xiv) Messrs. Thomas L. Kempner, Jr., Marvin H. Davidson, Stephen M. Dowicz, Scott E. Davidson, Michael J. Leffell, Timothy I. Levart, Robert J. Brivio, Jr., Anthony A. Yoseloff, Eric P. Epstein, Avram Z. Friedman and Conor Bastable (collectively, the "Principals"), who are the general partners of CO and MHD, the sole managing members of DKIA and DKG and the sole stockholders of DKAI. Messrs. Thomas L. Kempner, Jr. and Timothy I. Levart are Executive Managing Member and Deputy Executive Managing Member, respectively, of DKS. Each of Messrs. Kempner and Levart, together with Messrs. Marvin H. Davidson, Stephen M. Dowicz, Scott E. Davidson, Michael J. Leffell, Robert J. Brivio, Jr., Anthony A. Yoseloff, Eric P. Epstein, Avram Z. Friedman and Conor Bastable are limited partners of DKMP.

ITEM 2(b). ADDRESS OF PRINCIPAL BUSINESS OFFICE:

The address of the principal business office of each of the Reporting Persons is c/o Davidson Kempner Partners, 65 East 55th Street, 19th Floor, New York, New York 10022.

ITEM 2(c). CITIZENSHIP:

(i) DKP - a New York limited partnership

(ii) DKIP - a Delaware limited partnership

(iii) CO – a New York limited partnership

(iv) DKIL – a British Virgin Islands corporation

(v) Serena – a Cayman Islands corporation

(vi) DKHF – a Delaware limited partnership

(vii) DKHI – a Cayman Islands corporation

(viii) MHD – a New York limited partnership

(ix) DKAI – a New York corporation

(x) DKIA – a Delaware limited liability company

(xi) DKG – a Delaware limited liability company

(xii) DKMP – a Delaware limited partnership

(xiii) DKS – a Delaware limited liability company

(xiv) Thomas L. Kempner, Jr. – United States

(xv) Marvin H. Davidson – United States

(xvi) Stephen M. Dowicz – United States

(xvii) Scott E. Davidson –United States

(xviii) Michael J. Leffell – United States

(xix) Timothy I. Levart – United Kingdom & United States

(xx) Robert J. Brivio, Jr. – United States

(xxi) Eric P. Epstein – United States

(xxii) Anthony A. Yoseloff – United States

(xxiii) Avram Z. Friedman – United States

(xxiv) Conor Bastable – United States

ITEM 2(d). TITLE OF CLASS OF SECURITIES:

COMMON STOCK, PAR VALUE $0.001

ITEM 2(e). CUSIP NUMBER:

574795100

ITEM 3. IF THIS STATEMENT IS FILED PURSUANT TO 13d-1(b) OR 13d-2(b) OR (c), CHECK WHETHER THE PERSON FILING IS A:

(a)[ ] Broker or dealer registered under Section 15 of the Act;

(b)[ ] Bank as defined in Section 3(a)(6) of the Act;

(c)[ ] Insurance Company as defined in Section 3(a)(19) of the Act;

(d)[ ] Investment Company registered under Section 8 of the Investment Company Act of 1940;

(e)[ ] Investment Adviser registered under Section 203 of the Investment Advisers Act of 1940: see Rule 13d-1(b)(1)(ii)(E);

(f)[ ] Employee Benefit Plan, Pension Fund which is subject to the provisions of the Employee Retirement Income Security Act of 1974 or Endowment Fund; see Rule 13d-1(b)(1)(ii)(F);

(g)[ ] Parent Holding Company, in accordance with Rule 13d-1(b)(ii)(G);

(h)[ ] Savings Associations as defined in Section 3(b) of the Federal Deposit Insurance Act;

(i)[ ] Church Plan that is excluded from the definition of an investment company under Section 3(c)(14) of the Investment Company Act of 1940;

(j)[ ] Group, in accordance with Rule 13d-1(b)(1)(ii)(J).

ITEM 4. OWNERSHIP.

A. DKP

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

B. DKIP

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

C. CO

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

D. DKIL

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

E. Serena

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

F. DKHF

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

G. DKHI

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

H. MHD

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

I. DKAI

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

J. DKIA

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

K. DKG

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

L. DKMP

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

M. DKS

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

N. Thomas L. Kempner, Jr.

a) Amount beneficially owned: 0

b) Percent of class: 0.0%

c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

O. Marvin H. Davidson

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

P. Stephen M. Dowicz

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

Q. Scott E. Davidson

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

R. Michael J. Leffell

(a) Amount beneficially owned. 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

S. Timothy I. Levart

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

T. Robert J. Brivio, Jr.

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

U. Eric P. Epstein

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

V. Anthony A. Yoseloff

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

W. Avram Z. Friedman

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

X. Conor Bastable

(a) Amount beneficially owned: 0

(b) Percent of class: 0.0%

(c) Number of shares as to which such person has:

(i) sole power to vote or to direct the vote: 0

(ii) shared power to vote or to direct the vote: 0

(iii) sole power to dispose or to direct the disposition: 0

(iv) shared power to dispose or to direct the disposition: 0

ITEM 5. OWNERSHIP OF FIVE PERCENT OR LESS OF A CLASS.

If this statement is being filed to report the fact that as of the date hereof the reporting person has ceased to be the beneficial owner of more than five percent of the class of securities, check the following [X].

ITEM 6. OWNERSHIP OF MORE THAN FIVE PERCENT ON BEHALF OF ANOTHER PERSON.

Not applicable.

ITEM 7. IDENTIFICATION AND CLASSIFICATION OF THE SUBSIDIARY WHICH ACQUIRED THE SECURITY BEING REPORTED ON BY THE PARENT HOLDING COMPANY.

Not applicable.

ITEM 8. IDENTIFICATION AND CLASSIFICATION OF MEMBERS OF THE GROUP.

See Item 4.

ITEM 9. NOTICE OF DISSOLUTION OF GROUP.

Not applicable.

ITEM 10. CERTIFICATION. (if filing pursuant to Rule 13d-1(c))

Each of the Reporting Persons hereby makes the following certification:

By signing below we certify that, to the best of our knowledge and belief, the securities referred to above were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect.

SIGNATURES

After reasonable inquiry and to the best of our knowledge and belief, the undersigned certify that the information set forth in this statement is true, complete and correct.

DATED: February 17, 2009

DAVIDSON KEMPNER PARTNERS
By: MHD Management Co.,
its General Partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Managing Partner

DAVIDSON KEMPNER INSTITUTIONAL
PARTNERS, L.P.
By: Davidson Kempner Advisers Inc.,
its General Partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: President

M.H. DAVIDSON & CO.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Managing Partner

DAVIDSON KEMPNER INTERNATIONAL,
LTD.
By: Davidson Kempner International Advisors,
L.L.C.,
its Investment Manager

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

SERENA LIMITED
By: Davidson Kempner International Advisors,
L.L.C.,
its Investment Manager

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DAVIDSON KEMPNER HEALTHCARE
FUND LP
By: DK Group LLC,
its General Partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DAVIDSON KEMPNER HEALTHCARE
INTERNATIONAL LTD.
By: DK Management Partners LP,
its Investment Manager
By: DK Stillwater GP LLC,
its general partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

MHD MANAGEMENT CO.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Managing Partner

DAVIDSON KEMPNER ADVISERS INC.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: President

DAVIDSON KEMPNER INTERNATIONAL
ADVISORS, L.L.C.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DK GROUP LLC

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DK MANAGEMENT PARTNERS LP
By: DK Stillwater GP LLC, its general partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DK STILLWATER GP LLC

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

/s/ Thomas L. Kempner, Jr.

Thomas L. Kempner, Jr.

/s/ Marvin H. Davidson

Marvin H. Davidson

/s/ Stephen M. Dowicz

Stephen M. Dowicz

/s/ Scott E. Davidson

Scott E. Davidson

/s/ Michael J. Leffell

Michael J. Leffell

/s/ Timothy I. Levart

Timothy I. Levart

/s/ Robert J. Brivio, Jr.

Robert J. Brivio, Jr.

/s/ Eric P. Epstein

Eric P. Epstein

/s/ Anthony A. Yoseloff

Anthony A. Yoseloff

/s/ Avram Z. Friedman

Avram Z. Friedman

/s/ Conor Bastable

Conor Bastable

EXHIBIT 1

JOINT ACQUISITION STATEMENT

PURSUANT TO RULE 13d-1(k)

The undersigned acknowledge and agree that the foregoing statement on Schedule 13G is filed on behalf of each of the undersigned and that all subsequent amendments to this statement on Schedule 13G, shall be filed on behalf of each of the undersigned without the necessity of filing additional joint acquisition statements. The undersigned acknowledge that each shall be responsible for the timely filing of such amendments, and for the completeness and accuracy of the information concerning him or it contained therein, but shall not be responsible for the completeness and accuracy of the information concerning the others, except to the extent that he or it knows or has reason to believe that such information is inaccurate.

DATED: February 17, 2009

DAVIDSON KEMPNER PARTNERS
By: MHD Management Co.,
its General Partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Managing Partner

DAVIDSON KEMPNER INSTITUTIONAL
PARTNERS, L.P.
By: Davidson Kempner Advisers Inc.,
its General Partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: President

M.H. DAVIDSON & CO.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Managing Partner

DAVIDSON KEMPNER INTERNATIONAL, LTD.
By: Davidson Kempner International Advisors, L.L.C.,
its Investment Manager

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

SERENA LIMITED
By: Davidson Kempner International Advisors, L.L.C.,
its Investment Manager

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DAVIDSON KEMPNER HEALTHCARE FUND LP
By: DK Group LLC,
its General Partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DAVIDSON KEMPNER HEALTHCARE INTERNATIONAL LTD.
By: DK Management Partners LP,
its Investment Manager
By: DK Stillwater GP LLC,
its general partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

MHD MANAGEMENT CO.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Managing Partner

DAVIDSON KEMPNER ADVISERS INC.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: President

DAVIDSON KEMPNER INTERNATIONAL
ADVISORS, L.L.C.

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DK GROUP LLC

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DK MANAGEMENT PARTNERS LP
By: DK Stillwater GP LLC, its general partner

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

DK STILLWATER GP LLC

/s/ Thomas L. Kempner, Jr.

Name: Thomas L. Kempner, Jr.
Title: Executive Managing Member

/s/ Thomas L. Kempner, Jr.

Thomas L. Kempner, Jr.

/s/ Marvin H. Davidson

Marvin H. Davidson

/s/ Stephen M. Dowicz

Stephen M. Dowicz

/s/ Scott E. Davidson

Scott E. Davidson

/s/ Michael J. Leffell

Michael J. Leffell

/s/ Timothy I. Levart

Timothy I. Levart

/s/ Robert J. Brivio, Jr.

Robert J. Brivio, Jr.

/s/ Eric P. Epstein

Eric P. Epstein

/s/ Anthony A. Yoseloff

Anthony A. Yoseloff

/s/ Avram Z. Friedman

Avram Z. Friedman

/s/ Conor Bastable

Conor Bastable

osses, net of tax of $15,041 25,150 25,150

Total comprehensive income
22,878

Balance at September 30, 2007
53,218 $533 $458,989 $ $391,980 $(10,177) $841,325

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(unaudited

	Nine months ended September 30, 2007	2006
Cash flows from operating activities:		
Net income (loss)	$ (2,272)	$ 82,306
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, and amortization	136,372	82,479
Non-cash exploration expense	22,511	12,542
Deferred taxes	1,374	48,673
Non-cash stock-based compensation expense	12,790	6,797
Non-cash derivative	87,108	(13,013)
Loss on disposition of assets	5,918	395
Minority interest in loss of consolidated partnership	(2,988)	
Other	6,055	5,644
Changes in operating assets and liabilities, net of effects from acquisitions:		
Accounts receivable	(31,064)	11,579
Current derivatives	(15,303)	(1,221)
Other current assets	(1,858)	(3,472)
Long-term derivatives	(22,301)	(29,097)
Other assets	(4,428)	(4)
Accounts payable	4,416	(2,047)
Other current liabilities	17,810	19,188
Other noncurrent liabilities	(496)	13,633
Net cash provided by operating activities	213,644	234,382
Cash flows from investing activities:		
Proceeds from disposition of assets	291,339	666
Purchases of other property and equipment	(2,443)	(3,450)
Acquisition of oil and natural gas properties	(839,945)	(22,809)
Development of oil and natural gas properties	(259,457)	(241,502)
Net advances to working interest partners	(22,644)	(8,667)
Other		(1,509)
Net cash used in investing activities	(833,150)	(277,271)
Cash flows from financing activities:		
Proceeds from issuance of common stock, net of issuance costs		127,101
Proceeds from issuance of ENP common units, net of issuance costs	171,220	
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	1,053	3,151

Proceeds from long-term debt, net of issuance costs	1,269,291	164,853
Payments on long-term debt	(805,428)	(245,000)
Change in cash overdrafts	10,293	(8,331)
Payment of deferred hedge premiums	(19,219)	
Net cash provided by financing activities	627,210	41,774
Increase (decrease) in cash and cash equivalents	7,704	(1,115)
Cash and cash equivalents, beginning of period	763	1,654
Cash and cash equivalents, end of period	$ 8,467	$ 539

The accompanying notes are an integral part of these consolidated financial statements.

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Table of Contents

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1. About Encore

EAC is engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Since 1998, EAC has acquired producing properties with proven reserves and leasehold acreage and grown the production and proven reserves by drilling, exploring, reengineering or expanding existing waterflood projects, and applying tertiary recovery techniques. EAC s properties and oil and natural gas reserves are located in four core areas: the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota; the Permian Basin of West Texas and southeastern New Mexico; the Rockies, which includes non-CCA assets in the Williston, Big Horn, and Powder River Basins of Wyoming, Montana, and North Dakota, and the Paradox Basin of southeastern Utah; and the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Barnett Shale of northern Texas.

Note 2. Basis of Presentation

EAC s consolidated financial statements include the accounts of wholly owned and majority-owned subsidiaries. All material intercompany balances and transactions have been eliminated in consolidation.

In February 2007, EAC formed ENP to acquire, exploit, and develop oil and natural gas properties and to acquire, own, and operate related assets. In September 2007, ENP completed its initial public offering (IPO) of 9,000,000 common units, representing a 37.4 percent limited partner interest, at a price to the public of $21.00 per unit. On September 30, 2007, EAC owned approximately 61 percent of ENP s common units, as well as all of the interests of ENP s general partner, which is a wholly owned subsidiary of EAC. Considering the presumption of control of the general partner in accordance with Emerging Issues Task Force Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* , the financial position, results of operations, and cash flows of ENP are consolidated within EAC s operations. EAC elected not to recognize a gain on ENP s IPO as permitted by Staff Accounting Bulletin Topic 5H, *Accounting for Sales of Stock by a Subsidiary* . See Note 16. ENP for additional discussion.

In the opinion of management, the accompanying unaudited consolidated financial statements of EAC include all adjustments necessary to present fairly, in all material respects, its financial position as of September 30, 2007, results of operations for the three and nine months ended September 30, 2007 and 2006, and cash flows for the nine months ended September 30, 2007 and 2006. All adjustments are of a normal recurring nature. These interim results are not necessarily indicative of results for an entire year.

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the SEC. Therefore, these consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in EAC s 2006 Annual Report on Form 10-K.

Variable Interest Entity

On April 11, 2007, EAC completed the purchase of certain oil and natural gas properties and related assets in the Williston Basin of Montana and North Dakota from certain subsidiaries of Anadarko Petroleum Corporation (Anadarko). Prior to closing, EAC assigned all of its rights and duties under the purchase and sale agreement to Encore Operating, L.P., a Texas limited partnership and indirect wholly owned guarantor subsidiary of EAC (Encore Operating), which further assigned all of its rights and duties under the purchase and sale agreement to Encore Exchange, LLC, a Delaware limited liability company unaffiliated with EAC or Encore Operating (Encore Exchange).

The Williston Basin acquisition was structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37. The Williston Basin assets were acquired by Encore Exchange as an exchange accommodation titleholder . Encore Exchange held the assets pursuant to a qualified exchange accommodation agreement until the second step of the like-kind exchange was completed. During the period the assets were held by Encore Exchange, Encore Operating operated the Williston Basin assets pursuant to a management agreement with Encore Exchange. The second step of the like-kind exchange was completed in July 2007 upon the completion of the disposition of certain of EAC s

Mid-Continent properties and the Williston Basin assets were transferred to EAC. See Note 3. Acquisitions and Dispositions for additional discussion of the Mid-Continent disposition.

In connection with the like-kind exchange described above, EAC (through Encore Operating) loaned an amount equal to the

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purchase price to Encore Exchange. Based on the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 46(R), *Consolidation of Variable Interest Entities* , EAC determined that Encore Exchange was a variable interest entity for which EAC was the primary beneficiary. During the third quarter of 2007, the like-kind exchange was completed, and Encore Exchange was dissolved.

Minority Interest

As presented in the accompanying Consolidated Balance Sheets, Minority interest in consolidated partnership as of September 30, 2007 of $181.4 million represents third-party ownership interests in ENP. For financial reporting purposes, the assets and liabilities of ENP are consolidated with those of EAC, with any third-party ownership interests in such amounts being presented as minority interest.

As presented in the accompanying Consolidated Statements of Operations, Minority interest in loss of consolidated partnership for the three and nine months ended September 30, 2007 of $3.0 million represents the net loss of ENP attributable to third-party owners.

Reclassifications

Certain amounts in prior periods have been reclassified to conform to the current period presentation. In particular, certain amounts on the accompanying Consolidated Statements of Cash Flows have been either combined or classified in more detail.

New Accounting Pronouncements

Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements (SFAS 157)

In September 2006, the FASB issued SFAS 157. SFAS 157 standardizes the definition of fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures related to the use of fair value measures in financial statements. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value measurements. SFAS 157 is prospectively effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. EAC does not expect the adoption of SFAS 157 to have a material impact on its results of operations or financial condition.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115 (SFAS 159)

In February 2007, the FASB issued SFAS 159. SFAS 159 permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. SFAS 159 allows entities to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. EAC does not expect the adoption of SFAS 159 to have a material impact on its results of operations or financial condition.

FASB Staff Position (FSP) on FIN 39-1, Amendment of FASB Interpretation No. 39 (FSP FIN 39-1)

In April 2007, the FASB issued FSP FIN 39-1. FSP FIN 39-1 amends FIN No. 39, *Offsetting of Amounts Related to Certain Contracts* (FIN 39), to permit a reporting entity that is party to a master netting arrangement to offset the fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with FIN 39. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. EAC does not expect the adoption of FSP FIN 39-1 to have a material impact on its results of operations or financial condition.

Note 3. Acquisitions and Dispositions

Acquisitions

On January 23, 2007, EAC entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil

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and natural gas properties and related assets in the Williston Basin of Montana and North Dakota. The closing of the Williston Basin acquisition occurred on April 11, 2007 after which time the operations have been included with those of EAC.

The total purchase price for the Williston Basin assets was approximately $392.0 million, including estimated transaction costs of approximately $1.3 million. Based on currently available information, the calculation of the total purchase price and the estimated allocation to the fair value of the Williston Basin assets acquired and liabilities assumed from Anadarko are as follows as of September 30, 2007 (in thousands):

Calculation of total purchase price:	
Cash paid to Anadarko	$ 390,728
Estimated transaction costs	1,298
Total purchase price	$ 392,026
Allocation of purchase price to the fair value of net assets acquired:	
Proved properties, including wells and related equipment	$ 383,741
Unproved properties	16,134
Accounts receivable	2,910
Inventory	743
Total assets acquired	403,528
Current liabilities	(7,996)
Future abandonment cost	(3,506)
Total liabilities assumed	(11,502)
Fair value of net assets acquired	$ 392,026

On January 16, 2007, EAC entered into a purchase and sale agreement with certain subsidiaries of Anadarko to acquire oil and natural gas properties and related assets in the Big Horn Basin of Wyoming and Montana, which included oil and natural gas properties and related assets in or near the Elk Basin field in Park County, Wyoming and Carbon County, Montana and oil and natural gas properties and related assets in the Gooseberry field in Park County, Wyoming. Prior to closing, EAC assigned the rights and duties under the purchase and sale agreement relating to the Elk Basin assets to Encore Energy Partners Operating LLC (OLLC), a Delaware limited liability company and wholly owned subsidiary of ENP, and the rights and duties under the purchase and sale agreement relating to the Gooseberry assets to Encore Operating. The closing of the Big Horn Basin acquisition occurred on March 7, 2007 after which time the operations have been included with those of EAC.

The total purchase price for the Big Horn Basin assets was approximately $393.2 million, including estimated transaction costs of approximately $1.3 million. The calculation of the total purchase price and the estimated allocation to the fair value of the Big Horn Basin assets acquired and liabilities assumed from Anadarko are as follows as of September 30, 2007 (in thousands):

Calculation of total purchase price:	
Cash paid to Anadarko	$ 391,943

Estimated transaction costs	1,288
Total purchase price	$ 393,231
Allocation of purchase price to the fair value of net assets acquired:	
Proved properties, including wells and related equipment	$ 395,598
Intangibles	4,225
Accounts receivable	1,673
Total assets acquired	401,496
Current liabilities	(1,292)
Future abandonment cost	(6,973)
Total liabilities assumed	(8,265)
Fair value of net assets acquired	$ 393,231

The properties and equipment amount in the Big Horn Basin purchase price allocation includes the fair value of proved leasehold costs, lease and well equipment (including flue gas reinjection facilities used to maintain reservoir pressure by

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compressing and reinjecting the gas produced), and an oil pipeline and natural gas pipeline used primarily to transport production from the acquired fields. NGLs are produced as a byproduct of the flue gas tertiary recovery project and are sold at market prices. The revenues generated by these hydrocarbon liquids are included in Oil revenues in the accompanying Consolidated Statements of Operations. Third-party revenues and expenses related to the pipelines are included in Marketing revenues and Marketing expenses , respectively, in the accompanying Consolidated Statements of Operations.

EAC and ENP financed the acquisitions of the Big Horn Basin and Williston Basin assets through borrowings under revolving credit facilities. As of December 31, 2006, estimated total proved reserves associated with the Big Horn Basin and Williston Basin acquisitions were 38,934 MBOE, 92 percent of which were oil and 90 percent of which were proved developed.

See Note 8. Debt for additional discussion of EAC s and ENP s revolving credit facilities. See Note 13. Financial Statements of Subsidiary Guarantors for a discussion of EAC s guarantor and non-guarantor subsidiaries.

Dispositions

On June 29, 2007, EAC completed the sale of certain oil and natural gas properties in the Mid-Continent. In July 2007, additional Mid-Continent properties that were subject to preferential rights were sold. The total net proceeds were approximately $289.7 million, including estimated transactions costs of approximately $3.5 million, and EAC recorded a loss on sale of approximately $5.8 million, which is included in Other operating expense in the accompanying Consolidated Statements of Operations. The disposed properties included certain properties in the Anadarko and Arkoma fields of Oklahoma. EAC retained a material oil and natural gas interest in other properties in the Anadarko and Arkoma fields and remains active in those areas.

Proceeds from the Mid-Continent disposition were used to reduce outstanding borrowings under EAC s revolving credit facility. As of December 31, 2006, estimated total proved reserves associated with the Mid-Continent disposition were 17,416 MBOE, 92 percent of which were natural gas and 75 percent of which were proved developed.

Pro Forma

The following unaudited pro forma condensed financial data for the three and nine months ended September 30, 2007 and 2006 was derived from the historical financial statements of EAC and from the accounting records of Anadarko to give effect to the Big Horn Basin and Williston Basin asset acquisitions and the Mid-Continent disposition as if they had occurred on January 1, 2006. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Big Horn Basin and Williston Basin acquisitions and the Mid-Continent disposition taken place as of the dates indicated and are not intended to be a projection of future results.

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
	(in thousands, except per share amounts)			
Pro forma total revenues	$ 195,016	$ 219,653	$ 522,778	$ 595,728
Pro forma net income	$ 14,171	$ 46,257	$ 4,879	$ 86,590
Pro forma net income per common share:				
Basic	$ 0.27	$ 0.87	$ 0.09	$ 1.68

Diluted	$ 0.26	$ 0.86	$ 0.09	$ 1.65

Note 4. Inventory

Inventory is comprised principally of materials and supplies and oil in pipelines, which are stated at the lower of cost (determined on an average basis) or market. Oil produced at the lease which resides unsold in pipelines is carried at an amount equal to its operating costs to produce. Oil in pipelines purchased from third parties is carried at average purchase price. EAC s inventory consisted of the following as of the dates indicated:

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	September 30, 2007	December 31, 2006
	(in thousands)	
Materials and supplies	$ 13,018	$ 11,784
Oil in pipelines	6,131	6,386
Total inventory	$ 19,149	$ 18,170

Note 5. Proved Properties

Amounts shown in the accompanying Consolidated Balance Sheets as Proved properties include leasehold costs and wells and related equipment, both completed and in process, and consisted of the following as of the dates indicated:

	September 30, 2007	December 31, 2006
	(in thousands)	
Proved leasehold costs	$ 1,325,112	$ 796,932
Wells and related equipment Completed	1,373,207	1,200,938
Wells and related equipment In process	42,486	36,044
Total proved properties	$ 2,740,805	$ 2,033,914

Note 6. Derivative Financial Instruments

EAC had $48.6 million of deferred premiums payable recorded at September 30, 2007, of which $21.7 million is considered long-term and recorded in Derivatives in the non-current liabilities section of the accompanying Consolidated Balance Sheet and $26.9 million is considered current and recorded in Derivatives in the current liabilities section of the accompanying Consolidated Balance Sheet. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from October 2007 to January 2010. EAC recorded these amounts at their net present value at the time the contract was entered into and accretes that value up to the eventual settlement price by recording interest expense each period.

Commodity Contracts Mark-to-Market Accounting: Previously designated as hedges

Prior to July 2006, EAC used hedge accounting for certain of its derivative contracts, whereby the effective portion of changes in the fair value of the contract was deferred, until the hedged production occurred, in accumulated other comprehensive loss (AOCL) included in stockholders equity in the accompanying Consolidated Balance Sheets rather than recognized currently in earnings. In the third quarter of 2006, EAC elected to discontinue hedge accounting prospectively for all remaining commodity derivatives which were previously accounted for as hedges. While this change has no effect on cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices. The deferred loss in AOCL at the time of dedesignation is being amortized to oil and natural gas revenues over the original term of the contracts. The amortization of these amounts is included in oil and natural gas revenues with the revenues from the hedged production. All mark-to-market gains and losses from July 2006 forward are recognized in earnings through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations rather than deferring such amounts in AOCL.

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The following tables summarize EAC s open commodity derivative instruments as of September 30, 2007:

Oil Derivative Instruments

Period	Daily Floor Volume (Bbl)	Average Floor Price (per Bbl)	Daily Short Floor Volume (Bbl)	Average Short Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Average Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Average Swap Price (per Bbl)	Asset (Liability) Fair Market Value (in thousands)
Oct. Dec. 2007	14,500	$ 56.72		$		$	3,000	$ 36.75	$ (11,847)
Jan. June 2008	18,500	62.84	(4,000)	50.00			1,000	58.59	256
July Dec. 2008	14,500	63.62	(4,000)	50.00					6,395
Jan. Dec. 2009	8,750	67.63	(5,000)	50.00			1,000	68.70	11,381
Jan. Dec. 2010	2,000	65.00			1,000	77.23			1,496
									$ 7,681

Natural Gas Derivative Instruments

Period	Daily Floor Volume (Mcf)	Average Floor Price (per Mcf)	Daily Short Floor Volume (Mcf)	Average Short Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Average Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Average Swap Price (per Mcf)	Asset Fair Market Value (in thousands)
Oct. Dec. 2007	36,500	$ 6.85		$	2,000	$ 9.85	10,000	$ 4.99	$ 1,562
Jan. Dec. 2008	24,000	6.58			2,000	9.85			5,019
Jan. Dec. 2009	4,000	7.70			2,000	9.85			992
									$ 7,573

Commodity Contracts Mark-to-Market Accounting: Floor Spreads

In order to partially finance the cost of premiums on certain purchased floors, EAC may sell floors with a strike price below the strike price of the purchased floor. Together the two floors, known as a floor spread or put spread, have a lower premium cost than a traditional floor contract but provide price protection only down to the strike price of the short floor. EAC has entered into floor spreads with a $70 per Bbl purchased floor and a $50 per Bbl short floor for 4,000 Bbls/D in 2008 and 5,000 Bbls/D in 2009. As with EAC s other derivative contracts, these are marked-to-market each quarter through Derivative fair value loss (gain) in the accompanying Consolidated Statements of Operations. In the above table, the purchased floor component of these floor spreads has been included with EAC s other floor contracts and the short floor component is shown separately as negative volumes.

Commodity Contracts Current Period Impact

EAC recognized a pre-tax reduction in oil and natural gas revenues of approximately $13.4 million and $14.4 million during the three months ended September 30, 2007 and 2006, respectively, and $40.2 million and

$45.7 million during the nine months ended September 30, 2007 and 2006, respectively, related to commodity derivative contracts which were previously designated as hedges. EAC also recognized derivative fair value gains and losses related to (i) changes in the market value since the date of dedesignation of derivative contracts which were previously designated as hedges, (ii) changes in the market value of certain other commodity derivatives that were never designated as hedges, (iii) settlements on derivative contracts not designated as hedges, and (iv) ineffectiveness of derivative contracts designated as hedges prior to July 2006. The following table summarizes the components of derivative fair value loss (gain) for the three and nine months ended September 30, 2007 and 2006:

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	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Ineffectiveness on designated cash flow hedges	$	$	$	$ 1,748
Mark-to-market loss (gain) on commodity contracts	9,686	(37,729)	56,122	(30,639)
Premium amortization	10,462	3,449	28,151	9,820
Settlements on commodity contracts	(4,362)	917	(16,107)	(1,192)
Total derivative fair value loss (gain)	$ 15,786	$ (33,363)	$ 68,166	$ (20,263)

Commodity Contracts Future Period Impact

At September 30, 2007 and December 31, 2006, AOCL consisted entirely of deferred losses on commodity derivatives which were previously designated as hedges of $10.2 million and $35.3 million, respectively.

EAC expects to reclassify the remaining $16.3 million of deferred losses associated with its dedesignated commodity contracts from AOCL to oil and natural gas revenues by June 30, 2008. EAC also expects to reclassify the remaining $6.1 million of net deferred tax assets from AOCL to income tax benefit by June 30, 2008.

Note 7. Asset Retirement Obligations

EAC s primary asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. EAC does not include a market risk premium in its risk estimates because a reliable estimate cannot be determined. As of September 30, 2007, EAC had $6.0 million held in an escrow account from which funds are released only for reimbursement of plugging and abandonment expenses on its Bell Creek property. This amount is included in Other assets in the accompanying Consolidated Balance Sheets. The following table summarizes the changes in EAC s future abandonment liability, the long-term portion of which is recorded in Future abandonment cost on the accompanying Consolidated Balance Sheets, for the nine months ended September 30, 2007 (in thousands):

Future abandonment liability at January 1, 2007	$ 19,841
Wells drilled	89
Accretion of discount	867
Plugging and abandonment costs incurred	(497)
Revision of estimates	(604)
Disposition of properties	(959)
Acquisition of properties	10,745
Future abandonment liability at September 30, 2007	$ 29,482

Note 8. Debt

EAC s long-term debt consisted of the following as of the dates indicated:

	September 30, 2007	December 31, 2006
	(in thousands)	

Revolving credit facilities	$ 545,000	$ 68,000
6 1/4% Senior Subordinated Notes due due April 15, 2014	150,000	150,000
6% Senior Subordinated Notes due July 15, 2015, net of unamortized discount of $4,555 and $4,892, respectively	295,445	295,108
7 1/4% Senior Subordinated Notes due December 1, 2017, net of unamortized discount of $1,346 and $1,412, respectively	148,654	148,588
Total	$ 1,139,099	$ 661,696

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Revolving Credit Facilities

Encore Acquisition Company Senior Secured Credit Agreement

On March 7, 2007, EAC entered into a five-year amended and restated credit agreement (the EAC Credit Agreement) with a bank syndicate comprised of Bank of America, N.A. and other lenders, which amended and restated EAC s Amended and Restated Credit Agreement dated as of August 19, 2004.

The EAC Credit Agreement provides for revolving credit loans to be made to EAC from time to time and letters of credit to be issued from time to time for the account of EAC or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the EAC Credit Agreement is $1.25 billion. Availability under the EAC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. Upon the contribution of certain assets in the Permian Basin to ENP at the closing of its IPO in September 2007, the borrowing base was reduced to $870 million. See Note 16. ENP for additional discussion.

The EAC Credit Agreement matures on March 7, 2012. EAC s obligations under the EAC Credit Agreement are secured by a first-priority security interest in EAC s and its restricted subsidiaries proved oil and natural gas reserves and in the equity interests of EAC s restricted subsidiaries. In addition, EAC s obligations under the EAC Credit Agreement are guaranteed by its restricted subsidiaries.

Loans under the EAC Credit Agreement are subject to varying rates of interest based on (i) the total amount outstanding in relation to the borrowing base and (ii) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for Eurodollar Loans	Applicable Margin for Base Rate Loans
Less than .50 to 1	1.000%	0.000%
Greater than or equal to .50 to 1 but less than .75 to 1	1.250%	0.000%
Greater than or equal to .75 to 1 but less than .90 to 1	1.500%	0.250%
Greater than or equal to .90 to 1	1.750%	0.500%

The Eurodollar rate for any interest period (either one, two, three, or six months, as selected by EAC) is the rate per year equal to LIBOR, as published by Reuters or another source designated by Bank of America, N.A., for deposits in dollars for a similar interest period. The base rate is calculated as the higher of (i) the annual rate of interest announced by Bank of America, N.A. as its prime rate and (ii) the federal funds effective rate plus 0.5 percent.

As of September 30, 2007, the aggregate principal amount of loans outstanding under the EAC Credit Agreement was $478.5 million and the aggregate face amount of outstanding letters of credit was $20 million, all of which related to EAC s joint development agreement with ExxonMobil Corporation (ExxonMobil). See Note 14. Commitments and Contingencies for additional discussion of this agreement. Any outstanding letters of credit reduce the availability under the EAC Credit Agreement. Borrowings under the EAC Credit Agreement may be repaid from time to time without penalty.

The EAC Credit Agreement contains covenants that include, among others:

a prohibition against incurring debt, subject to permitted exceptions;

a prohibition against paying dividends or making distributions, purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;

a restriction on creating liens on EAC s and its restricted subsidiaries assets, subject to permitted exceptions;

restrictions on merging and selling assets outside the ordinary course of business;

restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;

a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;

a requirement that EAC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0; and

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a requirement that EAC maintain a ratio of consolidated EBITDA (as defined in the EAC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0.

The EAC Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the EAC Credit Agreement to be immediately due and payable. EAC was in compliance with all of the debt covenants under the EAC Credit Agreement as of September 30, 2007.

EAC incurs a commitment fee on the unused portion of the EAC Credit Agreement determined based on the ratio of amounts outstanding under the EAC Credit Agreement to the borrowing base in effect on such date. The following table summarizes the calculation of the commitment fee under the EAC Credit Agreement:

Ratio of Total Outstanding Borrowings to Borrowing Base	Commitment Fee Percentage
Less than .50 to 1	0.250%
Greater than or equal to .50 to 1 but less than ..75 to 1	0.300%
Greater than or equal to .75 to 1 but less than ..90 to 1	0.375%
Greater than or equal to .90 to 1	0.375%

Encore Energy Partners Operating LLC Credit Agreement

OLLC is a party to a five-year credit agreement dated March 7, 2007 (the OLLC Credit Agreement) with a bank syndicate comprised of Bank of America, N.A. and other lenders. On August 22, 2007, OLLC entered into the First Amendment to the OLLC Credit Agreement, which revised certain financial covenants. The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries.

The aggregate amount of the commitments of the lenders under the OLLC Credit Agreement is $300 million. Availability under the OLLC Credit Agreement is subject to a borrowing base, which is redetermined semi-annually and upon requested special redeterminations. As a result of the contribution of certain assets in the Permian Basin from EAC to OLLC at the closing of ENP s IPO in September 2007, the borrowing base was increased to $145 million.

The OLLC Credit Agreement matures on March 7, 2012. OLLC s obligations under the OLLC Credit Agreement are secured by a first-priority security interest in OLLC s and its restricted subsidiaries proved oil and natural gas reserves and in the equity interests of OLLC and its restricted subsidiaries. In addition, OLLC s obligations under the OLLC Credit Agreement are guaranteed by its direct parent, ENP, and OLLC s restricted subsidiaries. EAC consolidates the debt of ENP with that of its own; however, obligations under the OLLC Credit Agreement are non-recourse to EAC and its restricted subsidiaries.

Loans under the OLLC Credit Agreement are subject to varying rates of interest based on the same provisions as the EAC Credit Agreement.

As of September 30, 2007, the aggregate principal amount of loans outstanding under the OLLC Credit Agreement was $66.5 million and there were no outstanding letters of credit. Any outstanding letters of credit reduce the availability under the OLLC Credit Agreement. Borrowings under the OLLC Credit Agreement may be repaid from time to time without penalty.

The OLLC Credit Agreement contains covenants that include, among others:

a prohibition against incurring debt, subject to permitted exceptions;

a prohibition against paying dividends or making distributions prior to the IPO Effective Date (as defined in the OLLC Credit Agreement), purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;

a restriction on creating liens on the assets of ENP, OLLC and its restricted subsidiaries, subject to permitted exceptions;

restrictions on merging and selling assets outside the ordinary course of business;

restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;

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a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 percent of anticipated production from proved producing reserves;

a requirement that OLLC maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0;

a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to the sum of consolidated net interest expense plus letter of credit fees of not less than 1.5 to 1.0;

a requirement that OLLC maintain a ratio of consolidated EBITDA (as defined in the OLLC Credit Agreement) to consolidated senior interest expense of not less than 2.5 to 1.0; and

a requirement that OLLC maintain a ratio of consolidated funded debt (excluding certain related party debt) to consolidated adjusted EBITDA (as defined in the OLLC Credit Agreement) of not more than 3.5 to 1.0.

The OLLC Credit Agreement contains customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate commitments may require Bank of America, N.A. to declare all amounts outstanding under the OLLC Credit Agreement to be immediately due and payable. At September 30, 2007, OLLC was in compliance with all of the debt covenants under the OLLC Credit Agreement, as amended.

OLLC incurs a commitment fee on the unused portion of the OLLC Credit Agreement determined based on the same provisions as the EAC Credit Agreement.

Note 9. Income Taxes

The components of the income tax provision were as follows for the nine months ended September 30, 2007 and 2006:

	Nine months ended September 30,	
	2007	**2006**
	(in thousands)	
Federal:		
Current	$ (116)	$ (1,361)
Deferred	(679)	(45,405)
Total federal	(795)	(46,766)
State, net of federal benefit/expense:		
Current		(1,348)
Deferred	(695)	(3,268)
Total state	(695)	(4,616)
Income tax provision	$ (1,490)	$ (51,382)

The following table reconciles income tax provision with income tax at the Federal statutory rate for the nine months ended September 30, 2007 and 2006:

	Nine months ended September 30,	
	2007	**2006**
	(in thousands)	
Income (loss) before income taxes	$ (782)	$ 133,688
Tax at statutory rate	$ 274	$ (46,791)
State income taxes, net of federal benefit/expense	19	(3,118)
Enactment of the Texas margin tax		(1,389)
Change in estimated future tax rate	(597)	
ENP minority interest in deferred compensation	(1,238)	
Permanent and other	52	(84)
Income tax provision	$ (1,490)	$ (51,382)

On January 1, 2007, EAC adopted the provisions of FIN No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes

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recognized in a company s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes* (SFAS 109). FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. EAC and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, EAC is no longer subject to U.S. federal, state, and local income tax examinations for years prior to 2003.

EAC has performed its evaluation of tax positions and has determined that the adoption of FIN 48 did not have a material impact on EAC s financial condition, results of operations, or cash flows. This evaluation is a review of the appropriate recognition threshold for each tax position recognized in EAC s financial statements. The evaluation included, but was not limited to:

- a review of documentation of tax positions taken on previous returns including an assessment of whether EAC followed industry practice or the applicable requirements under the tax code;
- a review of open tax returns (on a jurisdiction by jurisdiction basis) as well as supporting documentation used to support those tax returns;
- a review of the results of past tax examinations;
- a review of whether tax returns have been filed in all appropriate jurisdictions;
- a review of existing permanent and temporary differences; and
- consideration of any tax planning strategies that may have been used to support realization of deferred tax assets.

Based on this evaluation, EAC did not identify any tax positions that did not meet the highly certain positions threshold. As a result, no additional tax expense, interest, or penalties have been accrued as a result of the review.

EAC includes interest assessed by the taxing authorities in Interest expense and penalties related to income taxes in Other expense on its Consolidated Statements of Operations. For the nine months ended September 30, 2007 and 2006, EAC recorded only a nominal amount of interest and penalties on certain tax positions.

Note 10. Earnings Per Share (EPS)

The following table reflects EPS computations for the three and nine months ended September 30, 2007 and 2006:

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
	(in thousands, except per share data)			
Numerator:				
Net income (loss)	$ 11,985	$ 42,135	$ (2,272)	$ 82,306
Denominator:				
Denominator for basic EPS:				
Weighted average shares outstanding	53,198	52,968	53,140	51,481
Effect of dilutive options and diluted restricted stock (a)	981	808		894

Denominator for diluted EPS	54,179	53,776	53,140	52,375
Net income (loss) per common share:				
Basic	$ 0.23	$ 0.80	$ (0.04)	$ 1.60
Diluted	$ 0.22	$ 0.78	$ (0.04)	$ 1.57

(a) For the three months ended September 30, 2007 and 2006, options to purchase 95,253 shares of common stock and 106,274 shares of common stock, respectively, were outstanding but not included in the above calculation of diluted EPS because their effect would have been antidilutive. For the nine months ended September 30, 2007 and 2006, options to purchase 1,422,350 shares of common stock and 95,395 shares of common stock, respectively, were outstanding but not included in the above calculation of diluted EPS because their effect would have been antidilutive. The effect of dilutive options and diluted restricted stock for the nine months ended September 30, 2007 and 2006 is an average of the effect of the dilutive options and diluted restricted stock for the first three quarters of each respective year.

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Note 11. Incentive Stock Plan

During 2000, EAC s Board of Directors (the Board) and stockholders approved the 2000 Incentive Stock Plan (the EAC Plan). The EAC Plan was amended and restated effective March 18, 2004. The purpose of the EAC Plan is to attract, motivate, and retain selected employees of EAC and to provide EAC with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of EAC and its subsidiaries and affiliates are eligible to be granted awards under the EAC Plan. The total number of shares of common stock reserved for issuance pursuant to the EAC Plan is 4,500,000. As of September 30, 2007, there were 849,538 shares available for issuance under the EAC Plan. Shares delivered or withheld for payment of the exercise price of an option, shares withheld for payment of tax withholding, or shares subject to options or other awards that expire or are terminated and restricted shares that are forfeited will again become available for issuance under the EAC Plan. The EAC Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Board. The Board also has a Restricted Stock Award Committee having Jon S. Brumley, EAC s Chief Executive Officer and President, as its sole member. The Restricted Stock Award Committee may grant up to 25,000 shares of restricted stock on an annual basis to non-executive employees at its discretion.

The EAC Plan contains the following individual limits:

- an employee may not be granted awards covering or relating to more than 225,000 shares of common stock in any calendar year;

- a non-employee director may not be granted awards covering or relating to more than 15,000 shares of common stock in any calendar year; and

- an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $1.0 million.

All options that have been granted under the EAC Plan have a strike price equal to the fair market value of EAC s common stock on the date of grant. Additionally, all options have a ten-year life and vest equally over a three-year period. Restricted stock granted under the EAC Plan vests over varying periods from one to five years, subject to performance-based vesting for certain members of senior management.

The compensation cost related to the EAC Plan that has been recorded in the accompanying Consolidated Statements of Operations for the nine months ended September 30, 2007 and 2006 was $7.0 million and $6.6 million, respectively. The income tax benefit related to the EAC Plan that has been recorded in the accompanying Consolidated Statements of Operations for the nine months ended September 30, 2007 and 2006 was $2.6 million and $2.4 million, respectively. During each of the nine months ended September 30, 2007 and 2006, EAC also capitalized $0.9 million of non-cash stock-based compensation cost as a component of Properties and equipment in the accompanying Consolidated Balance Sheets. Non-cash stock-based compensation expense has been allocated to lease operations expense, general and administrative expense, and exploration expense based on the allocation of the respective employees cash compensation.

See Note 16. ENP for a discussion of ENP s unit-based compensation plan.

Stock Options

The fair value of each option award granted during the nine months ended September 30, 2007 and 2006 was estimated on the date of grant using the Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility is based on the historical volatility of EAC s common stock for a period of time commensurate with the expected term of the award. EAC uses the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options, which is calculated as the average midpoint between each vesting date and the life of the option. The risk-free rate is based on the U.S Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

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	Nine months ended September 30,	
	2007	**2006**
Expected volatility	35.7%	42.8%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.0	6.0
Risk-free interest rate	4.8%	4.6%

The following table summarizes the change in the number of outstanding options and the related weighted average strike prices during the nine months ended September 30, 2007:

	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2007	1,337,118	$14.44		
Granted	200,059	25.73		
Forfeited	(23,118)	28.30		
Exercised	(91,709)	13.10		
Outstanding at September 30, 2007	1,422,350	15.89	5.8	$22,415
Exercisable at September 30, 2007	1,141,977	13.16	5.0	21,111

The weighted average fair value per share of individual options granted during the nine months ended September 30, 2007 and 2006 was $11.16 and $14.96, respectively. The total intrinsic value of options exercised during the nine months ended September 30, 2007 and 2006 was $1.3 million and $2.4 million, respectively. During the nine months ended September 30, 2007 and 2006, EAC received proceeds from the exercise of stock options of $1.0 million and $2.3 million, respectively, and realized tax benefits related to stock options of $0.4 million and $0.9 million, respectively. At September 30, 2007, EAC had $1.6 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of 2.0 years.

Restricted Stock

During the nine months ended September 30, 2007 and 2006, EAC recognized expense related to restricted stock of $5.8 million and $5.6 million, respectively, and realized tax benefits related to restricted stock of $2.2 million and $2.1 million, respectively. A summary of the status of EAC s unvested restricted stock outstanding as of September 30, 2007, and changes during the nine months then ended, is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2007	828,619	$26.17
Granted	342,133	25.90

Vested	(118,273)	25.40
Forfeited	(61,145)	26.22
Outstanding at September 30, 2007	991,334	26.17

As of September 30, 2007, there were 819,059 shares of unvested restricted stock outstanding, dependent only on the passage of time and continued employment for vesting, 159,869 shares of which were granted during the nine months ended September 30, 2007. Additionally, as of September 30, 2007, there were 172,275 shares of unvested restricted stock outstanding that not only depend on the passage of time and continued employment, but on certain performance measures for vesting, all of which were granted during the nine months ended September 30, 2007. None of EAC s unvested restricted stock outstanding are subject to variable accounting.

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As of September 30, 2007, EAC had $11.3 million of total unrecognized compensation cost related to unvested, outstanding restricted stock, which is expected to be recognized over a weighted average period of 2.7 years. During the nine months ended September 30, 2007 and 2006, there were 118,273 shares and 27,909 shares, respectively, of restricted stock that vested and employees elected to satisfy minimum tax withholding obligations related to these shares by allowing EAC to withhold 5,545 shares and 6,553 shares of common stock, respectively. These shares are treated as treasury stock by EAC until the shares are formally retired and have been reflected as such in the accompanying consolidated financial statements.

Note 12. Comprehensive Income

Components of comprehensive income, net of related tax, are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Net income (loss)	$ 11,985	$ 42,135	$ (2,272)	$ 82,306
Amortization of deferred loss on commodity derivatives	8,596	8,894	25,150	28,448
Amortization of deferred gain on interest rate swap		(63)		(92)
Comprehensive income	$ 20,581	$ 50,966	$ 22,878	$ 110,662

Note 13. Financial Statements of Subsidiary Guarantors

In February 2007, EAC formed certain non-guarantor subsidiaries in connection with the formation of ENP. See Note 16. ENP for additional discussion of ENP s formation and other matters. As of September 30, 2007, certain of EAC s wholly owned subsidiaries were subsidiary guarantors of EAC s outstanding notes. The subsidiary guarantees are full and unconditional, and joint and several. The subsidiary guarantors may, without restriction, transfer funds to EAC in the form of cash dividends, loans, and advances. In accordance with SEC rules, EAC has prepared condensed consolidating financial statements in order to quantify the assets and results of operations of the subsidiary guarantors. The following Condensed Consolidating Balance Sheet as of September 30, 2007, Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and nine months ended September 30, 2007, and Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2007 present consolidating financial information for Encore Acquisition Company (Parent) on a stand alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries. The guarantor subsidiaries are:

EAP Energy, Inc.;

EAP Properties Inc.;

EAP Operating Inc.;

EAP Energy Services, L.P.;

Encore Operating; and

Encore Operating Louisiana, LLC.

The non-guarantor subsidiaries are:

ENP;

OLLC;

Encore Partners GP Holdings LLC;

Encore Partners LP Holdings LLC;

Encore Energy Partners GP LLC; and

Encore Clear Fork Pipeline LLC.

All intercompany investments in, loans due to/from, subsidiary equity, income and expenses between the Parent, the guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to final consolidation with the Parent and then eliminated to arrive at consolidated totals per the accompanying consolidated financial statements of EAC. Prior to February 2007, all of EAC s subsidiaries were subsidiary guarantors of EAC s outstanding senior notes. Therefore, comparative condensed consolidating financial statements are not presented as of December 31, 2006 or for the three and nine months ended September 30, 2006.

Income taxes in the Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) are shown as an expense of the Parent as EAC files a consolidated return. Additionally, EAC s net current deferred tax asset and net long-term deferred tax liability have been included in the balance sheet of the Parent in the Condensed Consolidating Balance Sheet.

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ENCORE ACQUISITION COMPANY
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CONDENSED CONSOLIDATING BALANCE SHEET
September 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$	$ 1,353	$ 7,114	$	$ 8,467
Other current assets	134,385	135,252	15,791	(121,255)	164,173
Total current assets	134,385	136,605	22,905	(121,255)	172,640
Properties and equipment, at cost successful efforts method:					
Proved properties, including wells and related equipment		2,369,011	371,794		2,740,805
Unproved properties		56,427			56,427
Accumulated depletion, depreciation, and amortization		(411,883)	(30,510)		(442,393)
		2,013,555	341,284		2,354,839
Other property and equipment, net		10,436	62		10,498
Other assets, net	15,571	142,649	13,960	(10,357)	161,823
Investment in subsidiaries	2,266,381			(2,266,381)	
Total assets	$ 2,416,337	$ 2,303,245	$ 378,211	$ (2,397,993)	$ 2,699,800
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 15,795	$ 278,283	$ 12,752	$ (121,255)	$ 185,575
Deferred taxes	294,849		122		294,971
Long-term debt	1,082,956		66,500	(10,357)	1,139,099
Other liabilities		46,363	11,055		57,418
Total liabilities	1,393,600	324,646	90,429	(131,612)	1,677,063
Commitments and contingencies (see Note 14)					

Minority interest in consolidated partnership	181,412				181,412
Total stockholders equity	841,325	1,978,599	287,782	(2,266,381)	841,325
Total liabilities and stockholders equity	$ 2,416,337	$ 2,303,245	$ 378,211	$ (2,397,993)	$ 2,699,800

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended September 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 141,185	$ 18,110	$	$ 159,295
Natural gas		29,523	2,916		32,439
Marketing		1,148	2,134		3,282
Total revenues		171,856	23,160		195,016
Expenses:					
Production:					
Lease operations		32,722	4,392		37,114
Production, ad valorem, and severance taxes		17,432	2,571		20,003
Depletion, depreciation, and amortization		40,668	8,358		49,026
Exploration		8,914	6		8,920
General and administrative	20	6,072	6,576		12,668
Marketing		2,789	1,300		4,089
Derivative fair value loss		12,797	2,989		15,786
Other operating	41	6,073	237		6,351
Total expenses	61	127,467	26,429		153,957
Operating income (loss)	(61)	44,389	(3,269)		41,059
Other income (expenses):					
Interest	(10,601)	(14,052)	(4,829)	5,549	(23,933)
Equity income (loss) from subsidiaries	25,775			(25,775)	
Other	2,794	3,565	47	(5,549)	857
Total other income (expenses)	17,968	(10,487)	(4,782)	(25,775)	(23,076)
Income (loss) before income taxes and minority interest	17,907	33,902	(8,051)	(25,775)	17,983
Income tax provision	(8,910)	(61)	(15)		(8,986)

Minority interest in loss of consolidated partnership	2,988				2,988
Net income (loss)	11,985	33,841	(8,066)	(25,775)	11,985
Amortization of deferred hedge (gains) losses, net of tax	(4,801)	13,397			8,596
Comprehensive income (loss)	$ 7,184	$ 47,238	$ (8,066)	$ (25,775)	$ 20,581

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued
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CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues:					
Oil	$	$ 338,935	$ 38,579	$	$ 377,514
Natural gas		101,728	8,820		110,548
Marketing		20,153	6,986		27,139
Total revenues		460,816	54,385		515,201
Expenses:					
Production:					
Lease operations		95,843	9,343		105,186
Production, ad valorem, and severance taxes		45,893	5,857		51,750
Depletion, depreciation, and amortization		117,602	18,770		136,372
Exploration		23,847	9		23,856
General and administrative	57	18,491	7,668		26,216
Marketing		21,952	5,655		27,607
Derivative fair value loss		58,680	9,486		68,166
Other operating	124	13,018	525		13,667
Total expenses	181	395,326	57,313		452,820
Operating income (loss)	(181)	65,490	(2,928)		62,381
Other income (expenses):					
Interest	(63,182)	(6,415)	(11,273)	12,830	(68,040)
Equity income (loss) from subsidiaries	53,098			(53,098)	
Other	6,419	8,226	74	(12,830)	1,889
Total other income (expenses)	(3,665)	1,811	(11,199)	(53,098)	(66,151)
Income (loss) before income taxes and minority interest	(3,846)	67,301	(14,127)	(53,098)	(3,770)
Income tax provision	(1,414)	(22)	(54)		(1,490)

Minority interest in loss of consolidated partnership	2,988				2,988
Net income (loss)	(2,272)	67,279	(14,181)	(53,098)	(2,272)
Amortization of deferred hedge (gains) losses, net of tax	(15,041)	40,191			25,150
Comprehensive income (loss)	$ (17,313)	$ 107,470	$ (14,181)	$ (53,098)	$ 22,878

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ENCORE ACQUISITION COMPANY
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CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Nine Months Ended September 30, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flows from operating activities:					
Net cash provided by operating activities	$	$ 199,333	$ 14,311	$	$ 213,644
Cash flows from investing activities:					
Proceeds from disposition of assets		291,339			291,339
Acquisition of oil and natural gas properties		(509,630)	(330,315)		(839,945)
Development of oil and natural gas properties		(256,797)	(2,660)		(259,457)
Investments in subsidiaries	(400,158)			400,158	
Other		(25,013)	(74)		(25,087)
Net cash provided by (used in) investing activities	(400,158)	(500,101)	(333,049)	400,158	(833,150)
Cash flows from financing activities:					
Proceeds from issuance of ENP common units, net of issuance costs			171,220		171,220
Exercise of stock options and vesting of restricted stock, net of treasury stock purchases	1,053				1,053
Proceeds from long-term debt, net of issuance costs	1,020,533		248,758		1,269,291
Payments on long-term debt	(621,428)		(184,000)		(805,428)
Net equity contributions		306,500	93,658	(400,158)	
Other		(5,142)	(3,784)		(8,926)
Net cash provided by (used in) financing activities	400,158	301,358	325,852	(400,158)	627,210
		590	7,114		7,704

Increase in cash and cash equivalents					
Cash and cash equivalents, beginning of period		763			763
Cash and cash equivalents, end of period	$	$ 1,353	$ 7,114	$	$ 8,467

Note 14. Commitments and Contingencies

Litigation

EAC is a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these proceedings will have a material adverse effect on EAC.

ExxonMobil

In March 2006, EAC entered into a joint development agreement with ExxonMobil to develop legacy natural gas fields in West Texas. Under the terms of the agreement, EAC will have the opportunity to develop approximately 100,000 gross acres. EAC will earn 30 percent of ExxonMobil s working interest and 22.5 percent of ExxonMobil s net revenue interest in each well drilled. EAC will operate each well during the drilling and completion phase, after which ExxonMobil will assume operational control of the well.

EAC will earn the right to participate in all fields by drilling a total of 24 commitment wells. During the commitment phase, ExxonMobil will have the option to receive non-recourse advanced funds from EAC attributable to ExxonMobil s 70 percent working interest in each commitment well. Once a commitment well is producing, ExxonMobil will repay 95 percent of the advanced funds plus accrued interest assessed on the unpaid balance through EAC s monthly receipt of future proceeds of oil and natural gas sales. As an alternative to receiving advanced funds during the commitment phase, ExxonMobil can elect to pay their share of capital costs for each well. After EAC has fulfilled its obligations under the commitment phase, it will be entitled to a 30 percent working interest in future drilling locations. EAC will have the right to propose and drill wells for as long as it is engaged in continuous drilling operations.

During the nine months ended September 30, 2007 and the year ended December 31, 2006, EAC advanced $30.8 million and $22.4 million, respectively, to ExxonMobil for its portion of capital related to drilling commitment wells, of which $48.0 million and $21.0 million remained outstanding at September 30, 2007 and December 31, 2006, respectively. At September 30,

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ENCORE ACQUISITION COMPANY
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2007, $2.5 million is included in Accounts receivable and $45.5 million is included in Long-term receivables on the accompanying Consolidated Balance Sheet based on when EAC expects repayment. At December 31, 2006, $3.0 million is included in Accounts receivable and $18.0 million is included in Long-term receivables on the accompanying Consolidated Balance Sheet. As of September 30, 2007, EAC had seven additional wells to drill in order to fulfill its drilling obligation under the joint development agreement at a minimum cost of $1.0 million per well.

Note 15. Related Party Transactions

EAC paid $1.3 million and $2.8 million to affiliates of Hanover Compressor Company (Hanover) during the nine months ended September 30, 2007 and 2006, respectively, for compressors and field compression services. Mr. I. Jon Brumley, EAC s Chairman of the Board, served as a director of Hanover until August 2007.

EAC also received $47.2 million and $5.9 million from affiliates of Tesoro Corporation (Tesoro) during the nine months ended September 30, 2007 and 2006, respectively, related to its working interest in wells operated by EAC. Mr. John V. Genova, a member of the Board, is employed by Tesoro.

Note 16. ENP

On September 17, 2007, ENP completed its IPO of 9,000,000 common units, representing a 37.4 percent limited partner interest, at a price to the public of $21.00 per unit. The net proceeds of $171.2 million, after deducting the underwriters discount and a structuring fee of $13.2 million, in the aggregate, and estimated offering expenses of $4.6 million, were used to repay in full the $126.4 million of outstanding indebtedness under ENP s subordinated credit agreement with EAP Operating Inc., and $43.5 million of outstanding borrowings under the OLLC Credit Agreement.

In connection with the closing of the IPO, EAC, ENP, and certain of their respective subsidiaries entered into a contribution, conveyance and assumption agreement (the Contribution Agreement) and an amended and restated administrative services agreement (the Administrative Services Agreement), each as more fully described below. In addition, prior to the IPO, Encore Energy Partners GP LLC approved a long-term incentive plan (the ENP Plan) for employees, consultants, and directors of Encore Operating, Encore Energy Partners GP LLC, and any of their affiliates who perform services for ENP, as more fully described below.

Contribution, Conveyance and Assumption Agreement

ENP entered into the Contribution Agreement with Encore Energy Partners GP LLC, ENP s general partner and wholly owned subsidiary of EAC, OLLC, EAC, Encore Operating, and Encore Partners LP Holdings LLC. At the closing of the IPO, the following transactions, among others, occurred pursuant to the Contribution Agreement:

- Encore Operating transferred certain assets in the Permian Basin, as described in the ENP s final prospectus (the Prospectus) dated September 11, 2007 (File No. 333-142847) and filed with the SEC on September 12, 2007, to ENP in exchange for 4,043,478 common units; and

- EAC agreed to indemnify ENP for certain environmental liabilities, tax liabilities, and title defects, as well as defects relating to retained assets and liabilities, occurring or existing before the closing.

These transfers and distributions were made in a series of steps outlined in the Contribution Agreement.

In connection with the issuance of the common units by ENP in exchange for the Permian Basin assets, the IPO, and the exercise of the underwriters option to purchase additional common units, Encore Energy Partners GP LLC exchanged such number of common units for general partner units as was necessary to enable it to maintain its two percent general partner interest. Encore Energy Partners GP LLC received the common units through capital contributions from EAC and its subsidiaries of common units they owned.

Administrative Services Agreement

ENP entered into the Administrative Services Agreement with Encore Energy Partners GP LLC, OLLC, Encore Operating,

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and EAC. As more fully described in the Prospectus, Encore Operating will perform administrative services for ENP, such as accounting, corporate development, finance, land, legal, and engineering. In addition, Encore Operating will provide all personnel and any facilities, goods, and equipment necessary to perform these services and not otherwise provided by the Partnership. Encore Operating will receive an administrative fee of $1.75 per BOE of ENP s production for such services and reimbursement of actual third-party expenses incurred on ENP s behalf.

In addition, Encore Operating is entitled to retain any COPAS overhead charges associated with drilling and operating wells that would otherwise be paid by non-operating interest owners to the operator of a well. Most joint operating agreements provide for an annual increase or decrease in the COPAS overhead rate for drilling and producing wells. The rate change, which occurs in April, is based on the change in average weekly earnings as measured by an index published by the United States Department of Labor, Bureau of Labor Statistics. The COPAS overhead cost is charged to all non-operating interest owners under a joint operating agreement each month.

ENP will also reimburse EAC for any additional state income, franchise, or similar tax paid by EAC resulting from the inclusion of ENP (and its subsidiaries) in a combined state income, franchise, or similar tax report with EAC as required by applicable law. The amount of any such reimbursement will be limited to the tax that ENP (and its subsidiaries) would have paid had it not been included in a combined group with EAC.

ENP does not have any employees. The employees supporting the operation of ENP are employees of Encore Operating. Accordingly, EAC recognizes all employee-related liabilities in its consolidated financial statements. Encore Operating has substantial discretion in determining which third-party expenses to incur on ENP s behalf. ENP also pays its share of expenses that are directly chargeable to wells under joint operating agreements. Encore Operating is not liable to ENP for its performance of, or failure to perform, services under the Administrative Services Agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Long-Term Incentive Plan

The ENP Plan is for employees, consultants, and directors of Encore Operating, Encore Energy Partners GP LLC, and any of their affiliates who perform services for ENP. As more fully described in the Prospectus, the ENP Plan provides for the grant of options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards, and unit awards. An aggregate of 1,150,000 common units may be delivered pursuant to awards under the ENP Plan. The ENP Plan will be administered by the board of directors of Encore Energy Partners GP LLC or a committee thereof, referred to as the plan administrator.

As of September 30, 2007, no awards had been granted under the ENP Plan.

Management Incentive Units

In May 2007, the board of directors of Encore Energy Partners GP LLC issued 550,000 management incentive units to the executive officers of Encore Energy Partners GP LLC. A management incentive unit is a limited partner interest in ENP that entitles the holder to an initial quarterly distribution of $0.35 (or $1.40 on an annualized basis) to the extent paid to ENP s common unitholders and to increasing distributions upon the achievement of 10 percent compounding increases in ENP s distribution rate to common unitholders. A management incentive unit is also convertible into common units upon the occurrence of certain events. The management incentive units are subject to a maximum limit on the aggregate number of common units issuable to, and the aggregate distributions payable to, holders of management incentive units as follows:

- the holders of management incentive units are not entitled to receive, in the aggregate, common units upon conversion of the management incentive units that exceed a maximum limit of 5.1 percent of all ENP s then-outstanding common units; and

- the holders of management incentive units are not entitled to receive, in the aggregate, distributions of ENP s available cash in an amount that exceeds a maximum limit of 5.1 percent of all such distributions to all unitholders at the time of any such distribution.

The holders of management incentive units do not have any voting rights with respect to the unit.

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The management incentive units vest in three equal installments. The first installment vested upon the closing of the IPO, and the subsequent vesting will occur on the first and second anniversary of such closing date. For the three and nine months ended September 30, 2007, ENP recognized total compensation expense for the management incentive units of $5.7 million, which is included in   General and administrative expense   in the accompanying Consolidated Statements of Operations. As of September 30, 2007, ENP had $5.8 million of total unrecognized compensation cost related to unvested, outstanding management incentive units, which is expected to be recognized over a weighted average period of 1.5 years. For the fourth quarter 2007 through the third quarter of 2008, the expense will be approximately $1.1 million per quarter, and for the fourth quarter 2008 through the third quarter of 2009, the expense will be approximately $0.4 million per quarter. There have been no additional issuances or forfeitures of management incentive units since the initial issuance.

Note 17. Subsequent Events

On October 11, 2007, the underwriters exercised their over-allotment option to purchase an additional 1,148,400 common units of ENP, representing an additional 2.9 percent limited partner interest, which closed on October 16, 2007. The Company expects to use the net proceeds of $22.4 million, after deducting the underwriters   discount of $1.7 million, to repay outstanding borrowings under the OLLC Credit Agreement.

On October 29, 2007, ENP issued 20,000 phantom units to members of the Encore Energy Partners GP LLC board of directors pursuant to the ENP Plan. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the plan administrator, cash equivalent to the value of a common unit. The phantom units vest in four equal installments beginning on the first anniversary of the date of grant. The holders of phantom units are also entitled to receive distribution equivalent rights prior to vesting, which entitle the grantee to receive cash equal to the amount of any cash distributions made by the Partnership with respect to a common unit during the period the right is outstanding.

On October 29, 2007, ENP declared a distribution for the third quarter of 2007 to unitholders of record as of the close of business on November 8, 2007. The $1.3 million total cash distribution will be paid on November 14, 2007 to unitholders at a rate of $0.053 per unit. The prorated quarterly distribution of $0.053 per unit is based on an initial quarterly distribution of $0.35 per unit, prorated for the period from and including September 17, 2007 (the closing date of the IPO) through September 30, 2007.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

This document contains forward-looking statements, which give our current expectations or forecasts of future events. Actual results may differ materially from those discussed in our forward-looking statements due to many factors, including, but not limited to, those set forth under Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006. The following discussion should be read in conjunction with the consolidated financial statements and notes thereto included in Item 1. Financial Statements of this Report and in Item 8. Financial Statements and Supplementary Data of our 2006 Annual Report on Form 10-K.

Introduction

In this management s discussion and analysis of financial condition and results of operations, the following will be discussed and analyzed:

- Third Quarter 2007 Highlights
- Results of Operations
  - Comparison of Quarter Ended September 30, 2007 to Quarter Ended September 30, 2006
  - Comparison of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2006
- Capital Resources
- Capital Commitments and Contingencies
- Liquidity
- Critical Accounting Policies and Estimates
- New Accounting Pronouncements

Third Quarter 2007 Highlights

Our financial and operating results for the third quarter of 2007 included the following:

- Our oil and natural gas revenues increased 46 percent to $191.7 million as compared to $131.7 million in the third quarter of 2006. Our oil and natural gas revenues increased as a result of increased production volumes and higher realized average prices.
- Our realized average oil price, including the effects of commodity derivative contracts, increased $8.68 per Bbl to $63.48 per Bbl as compared to $54.80 per Bbl in the third quarter of 2006. Our realized average natural gas price, including the effects of commodity derivative contracts, increased $0.21 per Mcf to $6.09 per Mcf as compared to $5.88 per Mcf in the third quarter of 2006.
- Production volumes increased 25 percent to 36,917 BOE/D as compared to 29,651 BOE/D for the third quarter of 2006. The rise in production volumes was primarily attributable to our Big Horn Basin and Williston Basin acquisitions and our development programs. Oil represented 74 percent and 67 percent of our total production volumes in the third quarter of 2007 and 2006, respectively.
- We invested $124.9 million in oil and natural gas activities (excluding related asset retirement obligations of $0.3 million). Of this amount, we invested $78.0 million in development, exploitation, HPAI expansion, and exploration activities, which yielded 49 gross (15.5 net) productive wells, and $46.9 million in acquisitions. We operated between six and nine drilling rigs, including four to six rigs related to our West Texas joint development agreement.

On September 17, 2007, ENP completed its IPO of 9,000,000 common units, representing a 37.4 percent limited partner interest in ENP, at a price to the public of $21.00 per unit. On October 11, 2007, the underwriters exercised their over- allotment option to purchase 1,148,400 additional ENP common units, representing an additional 2.9 percent limited partner interest in ENP. EAC currently owns approximately 58.0 percent of ENP s common units, as well as all the interests of ENP s general partner, which a wholly owned subsidiary of EAC.

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Results of Operations

Comparison of Quarter Ended September 30, 2007 to Quarter Ended September 30, 2006

Oil and natural gas revenues and production. The following table illustrates the primary components of oil and natural gas revenues for the three months ended September 30, 2007 and 2006, as well as each quarter s respective oil and natural gas production volumes:

	Three months ended September 30,			
	2007	**2006**	***Increase / (Decrease)***	
Revenues (in thousands):				
Oil wellhead	$ 170,118	$ 112,959	*$ 57,159*	
Oil hedges	(10,823)	(13,443)	*2,620*	
Total oil revenues	$ 159,295	$ 99,516	*$ 59,779*	*60%*
Natural gas wellhead	$ 35,012	$ 33,144	*$ 1,868*	
Natural gas hedges	(2,573)	(967)	*(1,606)*	
Total natural gas revenues	$ 32,439	$ 32,177	*$ 262*	*1%*
Combined wellhead	$ 205,130	$ 146,103	*$ 59,027*	
Combined hedges	(13,396)	(14,410)	*1,014*	
Total combined oil and natural gas revenues	$ 191,734	$ 131,693	*$ 60,041*	*46%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 67.80	$ 62.20	*$ 5.60*	
Oil hedges ($/Bbl)	(4.32)	(7.40)	*3.08*	
Total oil revenues ($/Bbl)	$ 63.48	$ 54.80	*$ 8.68*	*16%*
Natural gas wellhead ($/Mcf)	$ 6.58	$ 6.06	*$ 0.52*	
Natural gas hedges ($/Mcf)	(0.49)	(0.18)	*(0.31)*	
Total natural gas revenues ($/Mcf)	$ 6.09	$ 5.88	*$ 0.21*	*4%*
Combined wellhead ($/BOE)	$ 60.39	$ 53.56	*$ 6.83*	
Combined hedges ($/BOE)	(3.94)	(5.28)	*1.34*	
Total combined oil and natural gas revenues ($/BOE)	$ 56.45	$ 48.28	*$ 8.17*	*17%*

Total production volumes:				
Oil (MBbls)	2,509	1,816	*693*	*38%*
Natural gas (MMcf)	5,323	5,471	*(148)*	*-3%*
Combined (MBOE)	3,396	2,728	*668*	*24%*
Average daily production volumes:				
Oil (Bbls/D)	27,275	19,740	*7,535*	*38%*
Natural gas (Mcf/D)	57,857	59,463	*(1,606)*	*-3%*
Combined (BOE/D)	36,917	29,651	*7,266*	*25%*
Average NYMEX prices:				
Oil (per Bbl)	$ 75.21	$ 70.62	*$ 4.59*	*6%*
Natural gas (per Mcf)	$ 6.16	$ 6.58	*$ (0.42)*	*-6%*

Oil revenues increased $59.8 million from $99.5 million in the third quarter of 2006 to $159.3 million in the third quarter of 2007. The increase is primarily due to an increase in oil production volumes of 693 MBbls, which contributed approximately $43.1 million in additional oil revenues. The increase in oil production volumes is primarily the result of our Big Horn Basin and Williston Basin acquisitions and our development programs.

Our average realized oil price increased $8.68 per Bbl as a result of an increase in our wellhead price and a decrease in the effects of commodity derivative contracts included in oil revenues. Our higher average oil wellhead price increased oil revenues by $14.0 million, or $5.60 per Bbl, and the decrease in the effects of commodity derivative contracts, which were previously designated as hedges, increased oil revenues by $2.6 million, or $3.08 per Bbl. Our average oil wellhead price increased as a result of increases in the overall market price for oil, as reflected in the increase in the average NYMEX price from $70.62 per

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Bbl in the third quarter of 2006 to $75.21 per Bbl in the third quarter of 2007.

Our oil wellhead revenue was reduced by $9.8 million and $7.1 million in the third quarter of 2007 and 2006, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $0.3 million from $32.2 million in the third quarter of 2006 to $32.4 million in the third quarter of 2007. The increase is primarily due to an increase in our average realized natural gas price. Our average realized natural gas price increased $0.21 per Mcf as a result of an increase in our wellhead price, partially offset by an increase in the effects of commodity derivative contracts, which were previously designated as hedges, included in natural gas revenues. Our higher average natural gas wellhead price increased natural gas revenues by $2.8 million, or $0.52 per Mcf, while the increase in the effects of commodity derivative contracts reduced natural gas revenues by $1.6 million, or $0.31 per Mcf. Our average natural gas wellhead price increased as a result of the tightening of our natural gas differential despite decreases in the overall market price for natural gas, as reflected in the decrease in the average NYMEX price from $6.58 per Mcf in the third quarter of 2006 to $6.16 per Mcf in the third quarter of 2007.

Production volumes decreased 148 MMcf, which reduced natural gas revenues by approximately $0.9 million. The decrease in natural gas production volumes is primarily the result of, 18,218 Mcf/D of natural gas production in the third quarter of 2006 associated with our Mid-Continent disposition, partially offset by production added through our development programs on the West Texas joint development agreement with ExxonMobil and in the Mid-Continent area.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the three months ended September 30, 2007 and 2006. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended September 30,	
	2007	**2006**
Oil wellhead ($/Bbl)	$ 67.80	$ 62.20
Average NYMEX ($/Bbl)	$ 75.21	$ 70.62
Differential to NYMEX	$ (7.41)	$ (8.42)
Oil wellhead to NYMEX percentage	90%	88%
Natural gas wellhead ($/Mcf)	$ 6.58	$ 6.06
Average NYMEX ($/Mcf)	$ 6.16	$ 6.58
Differential to NYMEX	$ 0.42	$ (0.52)
Natural gas wellhead to NYMEX percentage	107%	92%

Our oil wellhead price as a percentage of the average NYMEX price tightened to 90 percent in the third quarter of 2007 as compared to 88 percent in the third quarter of 2006. We expect our oil wellhead differentials to remain approximately constant or to widen slightly in the fourth quarter of 2007 as compared to the third quarter of 2007 due to continued production increases from competing Canadian and Rocky Mountain producers, limited refining and pipeline capacity in the Rocky Mountain area, and corresponding steep pricing discounts.

Our natural gas wellhead price as a percentage of the average NYMEX price improved to 107 percent in the third quarter of 2007 as compared to 92 percent in the third quarter of 2006. The differential improved because of efforts to reduce natural gas transportation and gathering costs. We expect our natural gas wellhead differentials to remain approximately constant or to widen slightly in the fourth quarter of 2007 as compared to the third quarter of 2007.

Marketing revenues and expenses. In 2006 and in declining quantities during 2007, we began purchasing third-party oil Bbls from a counterparty other than to whom the Bbls were sold for aggregation and sale with our own equity production in various markets. These purchases assist us in marketing our production by decreasing our dependence on individual markets. These activities allow us to aggregate larger volumes, facilitate our efforts to maximize the prices we receive for production, provide for a greater allocation of future pipeline capacity in the event of curtailments, and enable us to reach other markets.

In March 2007, we acquired a natural gas pipeline from Anadarko as part of the Big Horn Basin acquisition. Natural gas volumes are purchased from numerous gas producers at the inlet to the pipeline and resold downstream to various local and off-system markets.

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The following table summarizes our marketing activities for the three months ended September 30, 2007 and 2006:

	Three months ended September 30,	
	2007	2006
	(in thousands, except per BOE amounts)	
Marketing revenues	$ 3,282	$ 46,004
Marketing expenses	4,089	48,001
Marketing, net	$ (807)	$ (1,997)
Marketing revenues per BOE	$ 0.97	$ 16.86
Marketing expenses per BOE	1.21	17.60
Marketing, net per BOE	$ (0.24)	$ (0.74)

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the three months ended September 30, 2007 and 2006:

	Three months ended September 30,		*Increase / (Decrease)*	
	2007	2006		
Expenses (in thousands):				
Production:				
Lease operations	$ 37,114	$ 24,478	*$ 12,636*	
Production, ad valorem, and severance taxes	20,003	13,560	*6,443*	
Total production expenses	57,117	38,038	*19,079*	*50%*
Other:				
Depletion, depreciation, and amortization	49,026	27,471	*21,555*	
Exploration	8,920	12,322	*(3,402)*	
General and administrative	12,668	6,250	*6,418*	
Derivative fair value loss (gain)	15,786	(33,363)	*49,149*	
Other operating	6,351	976	*5,375*	
Total operating	149,868	51,694	*98,174*	*190%*
Interest	23,933	11,261	*12,672*	
Income tax provision	8,986	25,069	*(16,083)*	
Total expenses	$ 182,787	$ 88,024	*$ 94,763*	*108%*

Expenses (per BOE):				
Production:				
Lease operations	$ 10.93	$ 8.97	*$ 1.96*	
Production, ad valorem, and severance taxes	5.89	4.97	*0.92*	
Total production expenses	16.82	13.94	*2.88*	*21%*
Other:				
Depletion, depreciation, and amortization	14.43	10.07	*4.36*	
Exploration	2.63	4.52	*(1.89)*	
General and administrative	3.73	2.29	*1.44*	
Derivative fair value loss (gain)	4.65	(12.23)	*16.88*	
Other operating	1.87	0.36	*1.51*	
Total operating	44.13	18.95	*25.18*	*133%*
Interest	7.05	4.13	*2.92*	
Income tax provision	2.65	9.19	*(6.54)*	
Total expenses	$ 53.83	$ 32.27	*$ 21.56*	*67%*

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Production expenses. Total production expenses increased $19.1 million from $38.0 million in the third quarter of 2006 to $57.1 million in the third quarter of 2007. This increase resulted from an increase in total production volumes, as well as a $2.88 increase in production expenses per BOE. Our production margin (defined as oil and natural gas revenues less production expenses) for the third quarter of 2007 increased by $41.0 million (44 percent) to $134.6 million in the third quarter of 2007 as compared to $93.7 million in the third quarter of 2006. Total production expenses per BOE increased by 21 percent while total oil and natural gas revenues per BOE increased by only 17 percent. On a per BOE basis, our production margin increased 15 percent to $39.63 per BOE for the third quarter of 2007 as compared to $34.34 per BOE for the third quarter of 2006.

The production expense attributable to lease operations expense (LOE) increased $12.6 million from $24.5 million in the third quarter of 2006 to $37.1 million in the third quarter of 2007, primarily as a result of an increase in production volumes, which contributed approximately $6.0 million of additional LOE, and an $1.96 increase in the average per BOE rate, which contributed approximately $6.6 million of additional LOE. The increase in production volumes is the result of our Big Horn Basin and Williston Basin acquisitions. The increase in our average LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increased operational activity to maximize production;
- HPAI expensed at the CCA; and
- higher salary levels for engineers and other technical professionals.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) increased $6.4 million from $13.6 million in the third quarter of 2006 to $20.0 million in the third quarter of 2007. The increase is due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of commodity derivative contracts), production taxes increased to 9.8 percent in the third quarter of 2007 as compared to 9.3 percent in the third quarter of 2006 as a result of higher rates in the states where the properties associated with the Williston Basin acquisition are located. The effect of commodity derivative contracts is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production taxes paid to taxing authorities.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $21.6 million from $27.5 million in the third quarter of 2006 to $49.0 million in the third quarter of 2007 due to an increase in the per BOE rate of $4.36 and increased production volumes. The increase in the per BOE rate was due to the higher cost basis of our recently acquired Big Horn Basin and Williston Basin properties, development of proved undeveloped reserves and higher finding, development, and acquisition costs resulting from increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $14.8 million, while the increase in production volumes resulted in additional DD&A expense of approximately $6.7 million.

Exploration expense. Exploration expense decreased $3.4 million from $12.3 million in the third quarter of 2006 to $8.9 million in the third quarter of 2007. During the third quarter of 2007, we expensed two exploratory dry holes totaling $5.7 million. During the third quarter of 2006, we expensed four exploratory dry holes totaling $10.0 million. However, impairment of unproved acreage in the third quarter of 2007 increased $1.0 million as compared to the third quarter of 2006 as we added additional leasehold costs and refined our estimated success rate in certain areas. The following table details our exploration expenses for the three months ended September 30, 2007 and 2006:

	Three months ended September 30, 2007	**2006**	***Increase / (Decrease)***
		(in thousands)	
Dry holes	$ 5,683	$ 9,962	*$ (4,279)*

Geological and seismic	153	222	*(69)*
Delay rentals	126	175	*(49)*
Impairment of unproved acreage	2,958	1,963	*995*
Total	$ 8,920	$ 12,322	*$ (3,402)*

General and administrative (G&A) expense. G&A expense increased $6.4 million from $6.3 million in the third quarter of 2006 to $12.7 million in the third quarter of 2007. The overall increase is primarily the result of $5.7 million of non-cash unit-based compensation related to ENP s management incentive units.

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Derivative fair value loss (gain). To increase clarity in our financial statements by accounting for all commodity derivative contracts under the same method, we elected to discontinue hedge accounting prospectively for all commodity derivative contracts beginning in July 2006. While this change has no effect on our cash flows, results of operations are affected by mark-to-market gains and losses, which fluctuate with the changes in oil and natural gas prices.

During the third quarter of 2007, we recorded a $15.8 million derivative fair value loss as compared to a $33.4 million derivative fair value gain in the third quarter of 2006, the components of which were as follows:

	Three months ended September 30, 2007	**2006**	***Increase / (Decrease)***
	(in thousands)		
Mark-to-market loss (gain) on commodity contracts	$ 9,686	$ (37,729)	*$ 47,415*
Premium amortization	10,462	3,449	*7,013*
Settlements on commodity contracts	(4,362)	917	*(5,279)*
Total derivative fair value loss (gain)	$ 15,786	$ (33,363)	*$ 49,149*

Other operating expense. Other operating expense increased $5.4 million from $1.0 million in the third quarter of 2006 to $6.4 million in the third quarter of 2007. The increase is primarily due to a $3.5 million loss on the sale of the Mid-Continent properties and increases in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of the production.

Interest expense. Interest expense increased $12.7 million from $11.3 million in the third quarter of 2006 to $23.9 million the third quarter of 2007. The increase is primarily due to additional debt used to finance the Big Horn Basin and Williston Basin acquisitions. The weighted average interest rate for all long-term debt for the third quarter of 2007 was 7.1 percent as compared to 6.9 percent for the third quarter of 2006.

The following table illustrates the components of interest expense for the three months ended September 30, 2007 and 2006:

	Three months ended September 30, 2007	**2006**	***Increase / (Decrease)***
	(in thousands)		
6 1/4% Notes	$ 2,427	$ 2,422	*$ 5*
6% Notes	4,631	4,624	*7*
7 1/4% Notes	2,747	2,745	*2*
Revolving credit facilities	13,186	550	*12,636*
Other	942	920	*22*
Total	$ 23,933	$ 11,261	*$ 12,672*

Minority interest. After ENP s IPO in September 2007 and the underwriters over-allotment exercise in October 2007, public unitholders have a limited partner interest of approximately 40.2 percent. We include ENP in our consolidated financial statements and show the ownership by the public as a minority interest. The minority interest loss in ENP was $3.0 million for the third quarter of 2007.

Income taxes. During the third quarter of 2007, we recorded an income tax provision of $9.0 million as compared to $25.1 million in the third quarter of 2006. Our effective tax rate increased to 42.9 percent in the third quarter of 2007 as compared to 37.3 percent in the third quarter of 2006 primarily due to a permanent rate adjustment for ENP s management incentive units.

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Comparison of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2006

Oil and natural gas revenues and production. The following table illustrates the primary components of oil and natural gas revenues for the nine months ended September 30, 2007 and 2006, as well as each period s respective oil and natural gas production volumes:

	Nine months ended September 30,			
	2007	**2006**	***Increase / (Decrease)***	
Revenues (in thousands):				
Oil wellhead	$ 409,985	$ 306,833	*$ 103,152*	
Oil hedges	(32,471)	(38,767)	*6,296*	
Total oil revenues	$ 377,514	$ 268,066	*$ 109,448*	*41%*
Natural gas wellhead	$ 118,267	$ 115,948	*$ 2,319*	
Natural gas hedges	(7,719)	(6,898)	*(821)*	
Total natural gas revenues	$ 110,548	$ 109,050	*$ 1,498*	*1%*
Combined wellhead	$ 528,252	$ 422,781	*$ 105,471*	
Combined hedges	(40,190)	(45,665)	*5,475*	
Total combined oil and natural gas revenues	$ 488,062	$ 377,116	*$ 110,946*	*29%*
Average realized prices:				
Oil wellhead ($/Bbl)	$ 58.35	$ 55.85	*$ 2.50*	
Oil hedges ($/Bbl)	(4.62)	(7.06)	*2.44*	
Total oil revenues ($/Bbl)	$ 53.73	$ 48.79	*$ 4.94*	*10%*
Natural gas wellhead ($/Mcf)	$ 6.44	$ 6.60	*$ (0.16)*	
Natural gas hedges ($/Mcf)	(0.42)	(0.39)	*(0.03)*	
Total natural gas revenues ($/Mcf)	$ 6.02	$ 6.21	*$ (0.19)*	*-3%*
Combined wellhead ($/BOE)	$ 52.37	$ 50.21	*$ 2.16*	
Combined hedges ($/BOE)	(3.98)	(5.42)	*1.44*	
Total combined oil and natural gas revenues ($/BOE)	$ 48.39	$ 44.79	*$ 3.60*	*8%*
Total production volumes:				

Oil (MBbls)		7,027		5,494	*1,533*	*28%*
Natural gas (MMcf)		18,359		17,555	*804*	*5%*
Combined (MBOE)		10,086		8,420	*1,666*	*20%*
Average daily production volumes:						
Oil (Bbls/D)		25,738		20,124	*5,614*	*28%*
Natural gas (Mcf/D)		67,249		64,304	*2,945*	*5%*
Combined (BOE/D)		36,946		30,842	*6,104*	*20%*
Average NYMEX prices:						
Oil (per Bbl)	$	66.21	$	68.23	*$ (2.02)*	*-3%*
Natural gas (per Mcf)	$	6.83	$	7.39	*$ (0.56)*	*-8%*

Oil revenues increased $109.4 million from $268.1 million in the first nine months of 2006 to $377.5 million in the first nine months of 2007. The increase is primarily due to an increase in oil production volumes of 1,533 MBbls, which contributed approximately $85.6 million in additional oil revenues. The increase in oil production volumes is primarily the result of our Big Horn Basin and Williston Basin acquisitions and our development programs.

Our average realized oil price increased $4.94 per Bbl as a result of an increase in our wellhead price and a decrease in the effects of commodity derivative contracts included in oil revenues. Our higher average oil wellhead price increased oil revenues by $17.6 million, or $2.50 per Bbl, and the decrease in the effects of commodity derivative contracts, which were previously designated as hedges, increased oil revenues by $6.3 million, or $2.44 per Bbl. Our average oil wellhead price increased as a result of the tightening of our oil differential despite decreases in the overall market price for oil, as reflected in the decrease in the average NYMEX price from $68.23 per Bbl in the first nine months of 2006 to $66.21 per Bbl in the first nine months of

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2007.

Our oil wellhead revenue was reduced by $20.0 million and $19.2 million in the first nine months of 2007 and 2006, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $1.5 million from $109.1 million for the first nine months of 2006 to $110.5 million for the first nine months of 2007. The increase is primarily due to an increase in production volumes of 804 MMcf, which contributed approximately $5.3 million in additional natural gas revenues. The increase in natural gas production volumes is the result of our West Texas joint development program with ExxonMobil and our development program in the Mid-Continent area, partially offset by natural gas production sold in conjunction with our Mid-Continent disposition. Our natural gas production volumes would have been 53,445 Mcf/D and 47,258 Mcf/D for the first nine months of 2007 and 2006, respectively, excluding volumes associated with our Mid-Continent disposition.

Our average realized natural gas price decreased $0.19 per Mcf as a result of a decrease in our wellhead price and an increase in the effects of commodity derivative contracts included in natural gas revenues. Our lower average natural gas wellhead price reduced natural gas revenues by $3.0 million, or $0.16 per Mcf, and the increase in the effects of commodity derivative contracts, which were previously designated as hedges, reduced natural gas revenues by $0.8 million, or $0.03 per Mcf. Our average natural gas wellhead price decreased as a result of decreases in the overall market price for natural gas, as reflected in the decrease in the average NYMEX price from $7.39 per Mcf in the first nine months of 2006 to $6.83 per Mcf in the first nine months of 2007.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of average NYMEX prices for the nine months ended September 30, 2007 and 2006. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Nine months ended September 30,	
	2007	**2006**
Oil wellhead ($/Bbl)	$ 58.35	$ 55.85
Average NYMEX ($/Bbl)	$ 66.21	$ 68.23
Differential to NYMEX	$ (7.86)	$ (12.38)
Oil wellhead to NYMEX percentage	88%	82%
Natural gas wellhead ($/Mcf)	$ 6.44	$ 6.60
Average NYMEX ($/Mcf)	$ 6.83	$ 7.39
Differential to NYMEX	$ (0.39)	$ (0.79)
Natural gas wellhead to NYMEX percentage	94%	89%

Our oil wellhead price as a percentage of the average NYMEX price tightened to 88 percent in the first nine months of 2007 as compared to 82 percent in the first nine months of 2006.

Our natural gas wellhead price as a percentage of the average NYMEX price tightened to 94 percent in the first nine months of 2007 as compared to 89 percent in the first nine months of 2006.

Marketing revenues and expenses. The following table summarizes our marketing activities for the nine months ended September 30, 2007 and 2006:

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	Nine months ended September 30, 2007	2006
	(in thousands, except per BOE amounts)	
Marketing revenues	$ 27,139	$ 106,036
Marketing expenses	27,607	105,661
Marketing, net	$ (468)	$ 375
Marketing revenues per BOE	$ 2.69	$ 12.59
Marketing expenses per BOE	2.74	12.55
Marketing, net per BOE	$ (0.05)	$ 0.04

Expenses. The following table summarizes our expenses, excluding marketing expenses shown above, for the nine months ended September 30, 2007 and 2006:

	Nine months ended September 30, 2007	2006	*Increase / (Decrease)*	
Expenses (in thousands):				
Production:				
Lease operations	$ 105,186	$ 70,332	*$ 34,854*	
Production, ad valorem, and severance taxes	51,750	38,382	*13,368*	
Total production expenses	156,936	108,714	*48,222*	*44%*
Other:				
Depletion, depreciation, and amortization	136,372	82,479	*53,893*	
Exploration	23,856	18,347	*5,509*	
General and administrative	26,216	18,199	*8,017*	
Derivative fair value loss (gain)	68,166	(20,263)	*88,429*	
Other operating	13,667	3,573	*10,094*	
Total operating	425,213	211,049	*214,164*	*101%*
Interest	68,040	33,766	*34,274*	
Income tax provision	1,490	51,382	*(49,892)*	
Total expenses	$ 494,743	$ 296,197	*$ 198,546*	*67%*

Expenses (per BOE):

Production:				
Lease operations	$ 10.43	$ 8.35	*$ 2.08*	
Production, ad valorem, and severance taxes	5.13	4.56	*0.57*	
Total production expenses	15.56	12.91	*2.65*	*21%*
Other:				
Depletion, depreciation, and amortization	13.52	9.80	*3.72*	
Exploration	2.37	2.18	*0.19*	
General and administrative	2.60	2.16	*0.44*	
Derivative fair value loss (gain)	6.76	(2.41)	*9.17*	
Other operating	1.35	0.42	*0.93*	
Total operating	42.16	25.06	*17.10*	*68%*
Interest	6.75	4.01	*2.74*	
Income tax provision	0.15	6.10	*(5.95)*	
Total expenses	$ 49.06	$ 35.17	*$ 13.89*	*39%*

Production expenses. Total production expenses increased $48.2 million from $108.7 million in the first nine months of 2006 to $156.9 million in the first nine months of 2007. This increase resulted from an increase in total production volumes, as

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well as a $2.65 increase in production expenses per BOE. Our production margin for the first nine months of 2007 increased by $62.7 million (23 percent) to $331.1 million in the first nine months of 2007 as compared to $268.4 million for the first nine months of 2006. Total production expenses per BOE increased by 21 percent while total oil and natural gas revenues per BOE increased by only eight percent. On a per BOE basis, our production margin increased three percent to $32.83 per BOE for the first nine months of 2007 as compared to $31.88 per BOE for the first nine months of 2006.

The production expense attributable to LOE increased $34.9 million from $70.3 million in the first nine months of 2006 to $105.2 million in the first nine months of 2007, primarily as a result of an $2.08 increase in the average per BOE rate, which contributed approximately $20.9 million of additional LOE, and an increase in production volumes, which contributed approximately $13.9 million of additional LOE. The increase in production volumes is the result of our Big Horn Basin and Williston Basin acquisitions. The increase in our average LOE per BOE rate was attributable to:

- increases in prices paid to oilfield service companies and suppliers;
- increased operational activity to maximize production;
- HPAI expensed at the CCA; and
- higher salary levels for engineers and other technical professionals.

The production expense attributable to production taxes increased $13.4 million from $38.4 million for the first nine months of 2006 to $51.8 million for the first nine months of 2007. The increase is due to higher wellhead revenues. As a percentage of oil and natural gas revenues (excluding the effects of commodity derivative contracts), production taxes increased to 9.8 percent in the first nine months of 2007 as compared to 9.1 percent in the first nine months of 2006 as a result of higher rates in the states where the properties associated with the Big Horn Basin and Williston Basin acquisitions are located.

DD&A expense. DD&A expense increased $53.9 million from $82.5 million for the first nine months of 2006 to $136.4 million for the first nine months of 2007 due to an increase in the per BOE rate of $3.72 and increased production volumes. The per BOE rate increased due to the higher cost basis of our recently acquired Big Horn Basin and Williston Basin properties, development of proved undeveloped reserves and higher finding, development, and acquisition costs resulting from increases in rig rates, oilfield services costs, and acquisition costs. These factors resulted in additional DD&A expense of approximately $37.6 million, while the increase in production volumes resulted in additional DD&A expense of approximately $16.3 million.

Exploration expense. Exploration expense increased $5.5 million from $18.3 million in the first nine months of 2006 to $23.9 million in the first nine months of 2007. During the first nine months of 2007, we expensed five exploratory dry holes totaling $14.7 million. During the first nine months of 2006, we expensed 11 exploratory dry holes totaling $12.5 million. In addition, impairment of unproved acreage in the first nine months of 2007 increased $4.0 million as compared to the first nine months of 2006 as we added additional leasehold costs and refined our estimated success rate in certain areas. The following table details our exploration expenses for the nine months ended September 30, 2007 and 2006:

	Nine months ended September 30,		***Increase / (Decrease)***
	2007	**2006**	
		(in thousands)	
Dry holes	$ 14,703	$ 12,542	*$ 2,161*
Geological and seismic	878	1,474	*(596)*
Delay rentals	467	530	*(63)*
Impairment of unproved acreage	7,808	3,801	*4,007*

Total	$ 23,856	$ 18,347	*$ 5,509*

G&A expense. G&A expense increased $8.0 million from $18.2 million in the first nine months of 2006 to $26.2 million in the first nine months of 2007. The overall increase is primarily the result of $5.7 million of non-cash unit-based compensation related to ENP s management incentive units, increased staffing to manage our larger asset base, higher activity levels, and increased personnel costs due to intense competition for human resources within the industry.

Derivative fair value loss (gain). During the first nine months of 2007, we recorded a $68.2 million derivative fair value loss as compared to a derivative fair value gain of $20.3 million in the first nine months of 2006, the components of which were as follows:

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	Nine months ended September 30, 2007	2006	*Increase / (Decrease)*
		(in thousands)	
Ineffectiveness on designated cash flow hedges	$	$ 1,748	*$ (1,748)*
Mark-to-market loss (gain) on commodity contracts	56,122	(30,639)	*86,761*
Premium amortization	28,151	9,820	*18,331*
Settlements on commodity contracts	(16,107)	(1,192)	*(14,915)*
Total derivative fair value loss (gain)	$ 68,166	$ (20,263)	*$ 88,429*

Other operating expense. Other operating expense increased $10.1 million from $3.6 million in the first nine months of 2006 to $13.7 million in the first nine months of 2007. The increase is primarily due to a $5.8 million loss on the sale of the Mid-Continent properties and increases in third-party transportation costs attributable to moving our CCA production into markets outside the immediate area of the production.

Interest expense. Interest expense increased $34.3 million from $33.8 million in the first nine months of 2006 to $68.0 million in the first nine months of 2007. The increase is primarily due to additional debt used to finance the Big Horn Basin and Williston Basin acquisitions. The weighted average interest rate for all long-term debt for the first nine months of 2007 was 7.0 percent as compared to 6.7 percent for the first nine months of 2006.

The following table illustrates the components of interest expense for the nine months ended September 30, 2007 and 2006:

	Nine months ended September 30, 2007	2006	*Increase / (Decrease)*
		(in thousands)	
6 1/4% Notes	$ 7,277	$ 7,262	*$ 15*
6% Notes	13,886	13,795	*91*
7 1/4% Notes	8,240	8,238	*2*
Revolving credit facilities	36,208	2,773	*33,435*
Other	2,429	1,698	*731*
Total	$ 68,040	$ 33,766	*$ 34,274*

Minority interest. After ENP s IPO in September 2007 and the underwriters over-allotment exercise in October 2007, public unitholders have a limited partner interest of approximately 40.2 percent. We include ENP in our consolidated financial statements and show the ownership by the public as a minority interest. The minority interest loss in ENP was $3.0 million for the first nine months of 2007.

Income taxes. During the first nine months 2007, we recorded an income tax provision of $1.5 million as compared to an income tax provision of $51.4 million in the first nine months of 2006. Our effective tax rate increased to 45.2 percent in the first nine months of 2007 as compared to 38.4 percent in the first nine months of 2006 primarily due to a permanent rate adjustment for ENP s management incentive units and a state rate adjustment due to larger apportionment of future taxable income to states with higher tax rates, partially offset by a benefit for the true-up to actual tax expense for the filing of our 2006 consolidated tax returns.

On January 1, 2007, we adopted the provisions of FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. We have performed an evaluation of tax positions and have determined that the adoption of FIN 48 did not have a material impact on our financial condition, results of operations, or cash flows.

Capital Resources

Our primary capital resources are as follows:

- Cash flows from operating activities; and
- Cash flows from financing activities.

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Cash flows from operating activities. Cash provided by operating activities decreased $20.7 million from $234.4 million for the first nine months of 2006 to $213.6 million for the first nine months of 2007. The decrease was primarily due to an increase in our net derivative liabilities as a result of increases in our commodity derivative positions and the forward price curve, and an increase in accounts receivable as a result of increased oil and natural gas sales, partially offset by an increase in our production margin.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt and net proceeds received from the sale of additional equity. We periodically draw on our revolving credit facilities to fund acquisitions and other capital commitments. Historically, we have repaid large balances on our revolving credit facilities with proceeds from the issuance of senior subordinated notes in order to extend the maturity date of the debt and fix the interest rate.

During the first nine months of 2007, we received net cash of $627.2 million from financing activities, including net borrowings on our revolving credit facilities of $463.9 million and net proceeds of $171.2 million from ENP s issuance of 9,000,000 common units in its IPO. Our net borrowings on our revolving credit facilities resulted in a net increase in outstanding borrowings under our revolving credit facilities from $68 million at December 31, 2006 to $545 million at September 30, 2007, primarily due to borrowings used to finance the Big Horn Basin and Williston Basin acquisitions, which were partially offset by repayments from the net proceeds received from the Mid-Continent disposition and ENP s IPO.

During the first nine months of 2006, we received net cash of $41.8 million from financing activities. This consisted primarily of net proceeds of $127.1 million from the issuance of 4,000,000 shares of our common stock in April 2006, which was used to reduce outstanding borrowings under our revolving credit facility, invest in oil and natural gas activities, and to pay general corporate expenses.

Current capitalization. At September 30, 2007, we had total assets of $2.7 billion and total capitalization of $2.0 billion, of which 42 percent was represented by stockholders equity and 58 percent by long-term debt. At December 31, 2006, we had total assets of $2.0 billion and total capitalization of $1.5 billion, of which 55 percent was represented by stockholders equity and 45 percent by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt is used to finance future capital projects or potential acquisitions.

Capital Commitments and Contingencies

Our primary needs for cash are as follows:

- Cash flows from investing activities including:
  - Development, exploitation, and exploration of existing oil and natural gas properties; and
  - Acquisitions of oil and natural gas properties and leasehold acreage;
- Funding of necessary working capital; and
- Contractual obligations.

Cash flows from investing activities. Cash used in investing activities increased $555.9 million from $277.3 million in the first nine months of 2006 to $833.2 million in the first nine months of 2007. The increase was primarily due to a $817.1 million increase in amounts paid for the acquisition of oil and natural gas properties, namely our Big Horn Basin and Williston Basin acquisitions, partially offset by a $290.7 million increase in amounts received for the disposition of oil and natural gas properties, primarily due to the Mid-Continent disposition.

Development, exploitation, and exploration of existing oil and natural gas properties. The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities during the three and nine months ended September 30, 2007 and 2006:

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	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
	(in thousands)			
Development and exploitation	$ 49,291	$ 63,499	$ 185,812	$ 159,394
Exploration	27,424	27,289	77,647	65,922
HPAI	1,252	4,454	3,248	18,913
Total	$ 77,967	$ 95,242	$ 266,707	$ 244,229

Development and exploitation. Our expenditures for development and exploitation investments primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities. Our development and exploitation capital for the third quarter of 2007 included a total of 35 gross (10.1 net) successful wells and one gross (0.9 net) development dry holes. Our development and exploitation capital for the first nine months of 2007 included a total of 123 gross (46.2 net) successful wells and three gross and (2.3 net) development dry holes.

We currently have eight operated rigs drilling on the onshore continental United States with one rig in the Mid-Continent, one rig in the Northern region, one rig in the New Mexico region, and five rigs in West Texas.

Exploration. Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. In the third quarter of 2007, our exploration capital yielded 14 gross (5.4 net) successful wells and two gross (1.1 net) exploratory dry holes. During the first nine months of 2007, our exploration capital yielded 42 gross (15.8 net) exploratory wells that were productive and five gross (2.6 net) exploratory dry holes.

HPAI. During the third quarter of 2007 and 2006, we invested $1.3 million and $4.5 million on our HPAI programs. For the first nine months of 2007 and 2006, we invested $3.2 million and $18.9 million on our HPAI programs.

Acquisitions of oil and natural gas properties and leasehold acreage. The following table summarizes our costs incurred (excluding asset retirement obligations) for oil and natural gas property acquisitions during the three and nine months ended September 30, 2007 and 2006:

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
	(in thousands)			
Acquisitions of proved property	$ 30,079	$ 263	$ 791,964	$ 4,315
Acquisitions of leasehold acreage	16,832	6,629	40,615	18,494
Total	$ 46,911	$ 6,892	$ 832,579	$ 22,809

Acquisitions. On March 7, 2007, we acquired oil and natural gas properties in the Big Horn Basin for a purchase price of approximately $393.2 million, including $1.3 million of estimated transaction costs. On April 11, 2007, we acquired oil and natural gas properties in the Williston Basin for a purchase price of approximately $392.0 million, including $1.3 million of estimated transaction costs. The total purchase price of these acquisitions allocated to proved properties was $779.3 million.

Leasehold acreage costs. During the three and nine months ended September 30, 2007, our capital expenditures for leasehold acreage totaled $16.8 million and $40.6 million, respectively. During the third quarter of 2007, our capital expenditures for leasehold acreage related to the acquisition of unproved acreage in various areas. During the first nine months of 2007, $16.1 million related to the Williston Basin acquisition and the remainder related to the acquisition of unproved acreage in various areas. During the three and nine months ended September 30, 2006, our capital expenditures for leasehold acreage totaled $6.6 million and $18.5 million, respectively, all of which related to the acquisition of unproved acreage in various areas.

Funding of necessary working capital. At September 30, 2007, our working capital (defined as total current assets less total current liabilities) was negative $12.9 million while at December 31, 2006 our working capital was negative $40.7 million, an improvement of $27.8 million. The improvement is primarily attributable to an increase in accounts receivable as a result of increased oil and natural gas sales.

For the remainder of 2007, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our commodity derivative contracts (the settlements of which will be offset by cash flows from the sale of

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production mitigated against price risk under those contracts) and deferred commodity derivative contract premiums. We anticipate cash reserves to be close to zero because we intend to use any excess cash to fund capital obligations and pay down any outstanding borrowings under our revolving credit facilities. We do not plan to pay cash dividends in the foreseeable future. Our production volumes and the overall 2007 commodity prices and our related differentials for oil and natural gas will be the largest variables affecting working capital. Our operating cash flow is determined in large part by production volumes and commodity prices. Assuming moderate to high commodity prices and constant or increasing production volumes, our operating cash flow should remain positive in 2007.

The Board has approved a capital budget of approximately $385 million for 2007. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities, timing of projects, and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, cash on hand, and borrowings under our revolving credit facilities.

Contractual obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at September 30, 2007:

Contractual Obligations and Commitments	Total	Quarter Ended December 31, 2007	Years Ended December 31, 2008 2009	Years Ended December 31, 2010 2011	Thereafter
			(in thousands)		
6 1/4% Notes (a)	$ 215,626	$ 4,688	$ 18,750	$ 18,750	$ 173,438
6% Notes (a)	444,000		36,000	36,000	372,000
7 1/4% Notes (a)	264,188	5,438	21,750	21,750	215,250
Revolving credit facilities (a)	722,841	19,054	76,218	76,218	551,351
Derivative obligations (b)	63,910	17,859	45,170	881	
Development commitments (c)	105,912	55,533	50,379		
Operating leases and commitments (d)	14,552	738	5,348	4,569	3,897
Asset retirement obligations (e)	156,371	358	2,862	2,862	150,289
Total	$ 1,987,400	$ 103,668	$ 256,477	$ 161,030	$ 1,466,225

(a) Amounts included in the table above include both principal and projected interest payments. Please read Note 8 of Notes to Consolidated Financial

Statements included in Item 1. Financial Statements for additional information regarding our long-term debt.

(b) Derivative obligations represent net liabilities for derivatives that were valued as of September 30, 2007. With the exception of $48.6 million of deferred premiums on derivative contracts, the ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk. Please read Item 3. Quantitative and Qualitative Disclosures about Market Risk and Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial

Statements for additional information regarding our derivative obligations.

(c) Development commitments include: authorized purchases for work in process of $38.8 million; future minimum payments for drilling rig operations of $60.1 million; and $7.0 million for minimum capital obligations associated with the remaining seven commitment wells to be drilled under the ExxonMobil joint development agreement. Also at September 30, 2007, we had $181.3 million of authorized purchases not placed to vendors (authorized AFEs), which were not accrued and are excluded from the above table but are budgeted for and expected to be made unless circumstances change.

(d) Operating leases and commitments include office space and equipment obligations that have non-cancelable lease terms in excess of one year of $13.0 million and future minimum payments for other operating commitments of $1.6 million.

(e) Asset retirement obligations represent the undiscounted future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal at the completion of field life. Please read Note 7 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our asset retirement obligations.

Other contingencies and commitments. In order to facilitate ongoing sales of our oil production in the CCA, we ship a portion of our production in pipelines downstream and sell to purchasers at major U.S. market hubs. From time to time, shipping delays, purchaser stipulations, or other conditions may require that we sell our oil production in periods subsequent to the period in which it is produced. In such case, the deferred sale would have an adverse effect in the period of production on reported production volumes, oil and natural gas revenues, and costs as measured on a unit-of-production basis.

The marketing of our CCA oil production is mainly dependent on transportation through the Bridger, Poplar, and Butte pipelines to markets in the Guernsey, Wyoming area. Alternative transportation routes and markets have been developed by moving a portion of the crude oil production through Enbridge Pipeline to the Clearbrook, Minnesota hub. In addition, new markets to the west have been identified and a portion of our crude oil is being moved that direction through the Rocky Mountain

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Pipeline. To a lesser extent, our production also depends on transportation through Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on Platte Pipeline are currently oversubscribed and have been subject to apportionment since December 2005, we were allocated transportation effective January 1, 2007. However, further restrictions on available capacity to transport oil through any of the above mentioned pipelines, or any other pipelines, or any refinery upsets could have a material adverse effect on our production volumes and the prices we receive for our production.

We expect the differential between the NYMEX price of crude oil and the wellhead price we receive to remain approximately constant or to widen slightly in the fourth quarter of 2007 as compared to the third quarter of 2007. In recent years, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually widened this differential. We cannot accurately predict crude oil differentials. Natural gas differentials are expected to remain approximately constant or to slightly widen in the fourth quarter of 2007 as compared to the third quarter of 2007. Increases in the differential between the NYMEX price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial position, and cash flows.

Liquidity

Our primary sources of liquidity are internally generated cash flows and the borrowing capacity under the EAC Credit Agreement. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt or equity securities, to fund any major acquisitions we might secure in the future and to maintain our financial flexibility.

Internally generated cash flows. Our internally generated cash flows, results of operations, and financing for our operations are largely dependent on oil and natural gas prices. Realized oil and natural gas prices for the first nine months 2007 increased by 10 percent and decreased by three percent, respectively, as compared to the first nine months of 2006. These prices have historically fluctuated widely in response to changing market forces. For the first nine months of 2007, approximately 70 percent of our production was oil. As we previously discussed, our oil wellhead differentials during the first nine months of 2007 tightened as compared to the first nine months of 2006, favorably impacting the amount of oil revenues we received on our oil production. We expect our oil and natural gas wellhead differentials to remain approximately constant or to widen slightly in the fourth quarter of 2007 as compared to the third quarter of 2007. To the extent oil and natural gas prices decline or we experience significant widening of our wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facilities may be adversely impacted. Prolonged periods of low oil and natural gas prices or sustained wider than historical wellhead differentials could cause us to not be in compliance with financial covenants under our revolving credit facilities and thereby affect our liquidity. We believe that our internally generated cash flows and unused availability under our revolving credit facilities are sufficient to fund our planned capital expenditures for the foreseeable future.

Revolving credit facilities. Our principal source of short-term liquidity is the EAC Credit Agreement, which matures on March 7, 2012.

On March 7, 2007, we entered into the EAC Credit Agreement with a bank syndicate comprised of Bank of America, N.A. and other lenders. The EAC Credit Agreement amended and restated our Amended and Restated Credit Agreement dated as of August 19, 2004, as amended. The borrowing base is redetermined semi-annually and upon requested special redeterminations and may be increased or decreased, up to a maximum of $1.25 billion. The borrowing base on September 30, 2007 was $870 million.

Also on March 7, 2007, OLLC entered into the OLLC Credit Agreement with a bank syndicate comprised of Bank of America, N.A. and other lenders. The OLLC Credit Agreement provides for revolving credit loans to be made to OLLC from time to time and letters of credit to be issued from time to time for the account of OLLC or any of its restricted subsidiaries. The borrowing base is redetermined semi-annually and upon requested special redeterminations and may be increased or decreased, up to a maximum of $300 million. The borrowing base on September 30, 2007 was $145 million. Amounts borrowed under the OLLC Credit Agreement may only be used to fund the operations of ENP.

On September 30, 2007 and October 31, 2007, EAC had $478.5 million and $483 million outstanding, respectively, and $371.5 million $367 million available to borrow, respectively, under the EAC Credit Agreement. On September 30, 2007 and October 31, 2007, ENP had $66.5 million and $60 million outstanding, respectively, and $78.5 million $84.9 million available to

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borrow, respectively, under the EAC Credit Agreement. Please read Note 8 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for additional information regarding our revolving credit facilities.

Debt covenants. At September 30, 2007, we were in compliance with all of our debt covenants.

Letters of credit. As of September 30, 2007 and October 31, 2007, EAC had $20 million in outstanding letters of credit, all of which related to its ExxonMobil joint development agreement. As of September 30, 2007 and October 31, 2007, ENP had none and $0.1 million in outstanding letters of credit, respectively.

Critical Accounting Policies and Estimates

On January 1, 2007, we adopted the provisions of FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with SFAS 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. See Note 9 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements for more information.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in our 2006 Annual Report on Form 10-K for more information.

New Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note 2 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information included in Quantitative and Qualitative Disclosures about Market Risk in our 2006 Annual Report on Form 10-K is incorporated herein by reference. Such information includes a description of our potential exposure to market risks, including commodity price risk and interest rate risk.

Commodity Price Sensitivity

Our outstanding commodity derivative contracts as of September 30, 2007 are discussed in Note 6 of Notes to Consolidated Financial Statements included in Item 1. Financial Statements. As of September 30, 2007, the fair market value of our oil and natural gas derivative contracts was a net asset of $7.7 million and $7.6 million, respectively. Based on our open commodity derivative positions at September 30, 2007, a $1.00 increase in the respective NYMEX prices for oil and natural gas would decrease our net derivative fair value asset by approximately $8.4 million, while a $1.00 decrease in the respective NYMEX prices for oil and natural gas would increase our net derivative fair value assets by approximately $10.7 million.

Interest Rate Sensitivity

At September 30, 2007, we had total long-term debt of $1.1 billion, which is recorded net of discount of $5.9 million. Of this amount, $150 million bears interest at a fixed rate of 6 1/4 percent, $300 million bears interest at a fixed rate of 6 percent, and $150 million bears interest at a fixed rate of 7 1/4 percent. The remaining outstanding long-term debt balance of $545 million is under our revolving credit facilities and is subject to floating market rates of interest that are linked to LIBOR.

At this level of floating rate debt, if LIBOR increased one percent, we would incur an additional $5.5 million of interest expense per year, and if the rate decreased one percent, we would incur $5.5 million less. Additionally, if LIBOR increased one percent, we estimate the fair value of our fixed rate debt at September 30, 2007 would decrease from $535.3 million to $501.2 million, and if the rate decreased one percent, we estimate the fair value would increase to $572.4 million.

Item 4. Controls and Procedures

In accordance with the Securities Exchange Act of 1934 (the Exchange Act) Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief

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Financial Officer, of the effectiveness of our disclosure controls and procedures as of September 30, 2007. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2007 to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC s rules and forms and that information required to be disclosed is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting that occurred during the third quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to ongoing legal proceedings in the ordinary course of business. Management does not believe the result of these legal proceedings will have a material adverse effect on us.

Item 1A. Risk Factors

In addition to the other information set forth in this Report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our 2006 Annual Report on Form 10-K, which could materially affect our business, financial condition, and/or future results. The risks described in our 2006 Annual Report on Form 10-K are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, or results of operations.

Item 6. Exhibits

Exhibits

3.1	Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company (incorporated by reference from EAC s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
3.1.2	Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of Encore Acquisition Company (incorporated by reference from EAC s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, filed with the SEC on May 5, 2005).
3.2	Second Amended and Restated Bylaws of Encore Acquisition Company (incorporated by reference from EAC s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, filed with the SEC on November 7, 2001).
10.1	First Amendment to Credit Agreement, dated August 22, 2007, by and among Encore Energy Partners Operating LLC, Encore Energy Partners LP, Bank of America, N.A., as administrative agent and L/C Issuer, Banc of America Securities LLC, as sole lead arranger and sole book manager and other lenders (incorporated by reference from Exhibit 10.1 to EAC s Current Report on Form 8-K, filed with the SEC on August 28, 2007).
10.2	Contribution, Conveyance and Assumption Agreement, dated as of September 17, 2007, by and among Encore Energy Partners LP, Encore Energy Partners GP LLC, Encore Acquisition Company, Encore Operating, L.P., Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Energy Partners Operating LLC (incorporated by reference from Exhibit 10.1 to EAC s Current Report on Form 8-K, filed with the SEC on September 21, 2007).

10.3	Amended and Restated Administrative Services Agreement, dated as of September 17, 2007, by and among Encore Energy Partners GP LLC, Encore Energy Partners LP, Encore Energy Partners Operating LLC, Encore Acquisition Company and Encore Operating, L.P. (incorporated by reference from Exhibit 10.2 to EAC s Current Report on Form 8-K, filed with the SEC on September 21, 2007).
31.1*	Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer).
31.2*	Rule 13a-14(a)/15d-14(a) Certification (Principal Financial Officer).
32.1*	Section 1350 Certification (Principal Executive Officer).
32.2*	Section 1350 Certification (Principal Financial Officer).
99.1*	Statement showing computation of ratios of earnings to fixed charges.

* Filed herewith.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

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Date: November 6, 2007

/s/ Robert C. Reeves
Robert C. Reeves
Senior Vice President, Chief Financial Officer, and Treasurer

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