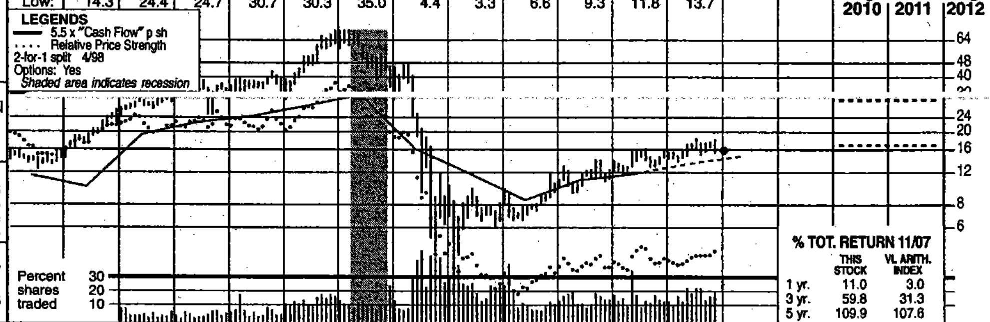
EL PASO CORP. NYSE-EP

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
15.91	15.4	(Trailing: 23.4 Median: 23.0)	0.90	1.0%	VALUE LINE

TIMELINESS **2** Raised 8/24/07
SAFETY **4** Raised 12/14/07
TECHNICAL **2** Raised 12/14/07
BETA 1.80 (1.00 = Market)

High:	26.6	33.8	38.9	43.4	74.3	75.3	46.9	10.3	11.9	14.2	16.4	18.6
Low:	14.3	24.4	24.7	30.7	30.3	35.0	4.4	3.3	6.6	9.3	11.8	13.7

Target Price Range
2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+90%)	*18%*
Low	17	(+5%)	*2%*

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	0	0	1	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	194	182	201
to Sell	170	184	156
Hld's(000)	526533	527299	525751

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	11.0	3.0
3 yr.	59.8	31.3
5 yr.	109.9	107.6

El Paso Natural Gas Company began supplying natural gas to the industrial complex of its namesake city in 1928. In March 1992, the company conducted an initial public offering of about 15% of its stock. A month later, Burlington Resources Inc., El Paso's parent company at the time, distributed the remaining 85% to its own stockholders. As part of a restructuring in August of 1998, the company reincorporated as El Paso Energy Corp., and a pipeline subsidiary assumed the original name. In February of 2000, it dropped "Energy" from its name.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB. INC.	10-12
47.13	48.07	46.09	90.21	108.29	20.34	11.23	9.14	6.09	6.14	*6.55*	*7.15*	Revenues per sh A	*8.15*
3.53	4.11	4.44	5.06	5.81	2.95	2.16	1.55	1.99	2.26	*2.45*	*2.70*	"Cash Flow" per sh	*3.20*
1.64	1.85	1.80	2.69	3.31	.64	.10	d.15	.34	.72	*.90*	*1.05*	Earnings per sh B	*1.35*
.73	.76	.80	.82	.85	.87	.16	.16	.16	.16	*.16*	*.16*	Div'ds Decl'd per sh C■	*.16*
2.45	3.38	4.73	5.49	12.66	6.20	4.10	2.77	2.61	3.10	*3.10*	*3.25*	Cap'l Spending per sh	*4.00*
16.37	17.53	12.84	14.67	17.63	13.97	7.49	5.35	4.00	4.93	*7.05*	*8.15*	Book Value per sh	*12.00*
119.64	120.29	229.60	243.32	530.73	599.57	597.56	642.93	659.46	697.12	*700.00*	*700.00*	Common Shs Outst'g D	*705.00*
17.6	18.5	20.2	18.9	17.0	37.5	NMF	--	33.6	21.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*17.0*
1.01	.96	1.15	1.23	.87	2.05	NMF	--	1.79	1.15	*estimates*		Relative P/E Ratio	*1.13*
2.5%	2.2%	2.2%	1.6%	1.5%	3.6%	2.2%	2.0%	1.4%	1.2%			Avg Ann'l Div'd Yield	*.7%*
5638.0	5782.0	10581	21950	57475	12194	6711.0	5874.0	4017.0	4281.0	*4585*	*5000*	Revenues ($mill) A	*5750*
13.4%	13.4%	14.0%	9.2%	7.8%	29.3%	43.3%	44.9%	57.4%	59.7%	*58.0%*	*59.0%*	Operating Margin	*61.0%*
236.0	269.0	609.0	589.0	1359.0	1405.0	1207.0	1088.0	1121.0	1047.0	*1025*	*1100*	Depreciation ($mill)	*1275*
211.0	250.0	435.0	643.0	1726.0	361.0	83.0	d92.0	248.0	531.0	*700*	*775*	Net Profit ($mill)	*985*
37.9%	33.7%	25.5%	33.0%	32.2%	27.5%	--	NMF	35.1%	--	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
3.7%	4.3%	4.1%	2.9%	3.0%	3.0%	1.2%	NMF	6.2%	12.4%	*15.3%*	*15.5%*	Net Profit Margin	*17.1%*
d835.0	d953.0	d791.0	d391.0	d906.0	1574.0	1848.0	1060.0	473.0	1016.0	*515*	*750*	Working Cap'l ($mill)	*1000*
2119.0	2552.0	5223.0	6574.0	14109	16307	20275	18241	17023	13329	*12800*	*12300*	Long-Term Debt ($mill)	*11000*
2259.0	2408.0	3272.0	3569.0	9356.0	8377.0	4474.0	3439.0	3389.0	4186.0	*4930*	*5705*	Shr. Equity ($mill)	*8450*
6.7%	7.2%	7.1%	7.9%	9.3%	3.9%	2.8%	3.1%	3.8%	6.5%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
9.3%	10.4%	13.3%	18.0%	18.4%	4.3%	1.9%	NMF	7.3%	12.6%	*14.0%*	*13.5%*	Return on Shr. Equity	*11.5%*
5.6%	6.4%	7.7%	12.7%	14.3%	NMF	NMF	NMF	2.8%	11.2%	*16.0%*	*15.0%*	Retained to Com Eq	*12.5%*
48%	46%	48%	29%	22%	NMF	NMF	NMF	60%	27%	*20%*	*19%*	All Div'ds to Net Prof	*15%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $13.0 bill. **Due in 5 Yrs** $6.1 bill.
LT Debt $12.4 bill. **LT Interest** $1.0 bill.
Incl. $750 million in preferred securities.
(Interest not covered) (71% of Cap'l)
Leases, Uncapitalized Annual rentals $43.0 mill.
Pension Assets-12/06 $2.7 bill. **Oblig.** $2.7 bill.

Common Stock 700,486,166 shares
as of 11/2/07
MARKET CAP: $11.1 billion (Large Cap)

CURRENT POSITION ($MILL.)	2005	2006	9/30/07
Cash Assets	2132	537	389
Receivables	1230	1203	850
Inventory (Avg Cst)	349	4161	--
Other	2474	1266	790
Current Assets	6185	7167	2029
Accts Payable	1329	1050	880
Debt Due	984	1360	567
Other	3399	3741	1330
Current Liab.	5712	6151	2777

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	-8.5%	-38.5%	*2.5%*
"Cash Flow"	-0.5%	-18.0%	*-8.0%*
Earnings	-14.0%	-36.0%	*35.0%*
Dividends	-13.0%	-28.0%	*Nil*
Book Value	-8.5%	-20.5%	*18.5%*

Calendar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1557	1524	1429	1364	5874
2005	1108	1184	768	957	4017
2006	1337	1089	942	913	4281E
2007	1022	1198	1166	*1199*	*4585*
2008	*1250*	*1250*	*1225*	*1275*	*5000*

Calendar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.07	.09	.27	d.58	d.15
2005	.12	.11	.05	.06	.34
2006	.40	.19	.16	d.03	.72
2007	.18	.29	.20	*.23*	*.90*
2008	*.29*	*.31*	*.25*	*.20*	*1.05*

Calendar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.04	.04	.04	.04	.16
2004	.04	.04	.04	.04	.16
2005	.04	.04	.04	.04	.16
2006	.04	.04	.04	.04	.16
2007	.04	.04	.04	.04	

BUSINESS: El Paso Corporation's (formerly El Paso Energy Corp.) operations include the transportation, gathering, processing, and storage of natural gas; the marketing of energy commodities; power generation; the exploration and production of natural gas and oil; and the development and operation of energy infrastructure facilities. Owns or has an interest in 55,000 miles of pipeline. It completed major acquisitions in '96, '99 & '01 and began an aggressive divestiture program in '02. Employs about 5050. Off. & dir. own less than 1% of common stock; Franklin Resources, 10.8% (3/07 Proxy). President & CEO: Douglas Foshee. Inc.: DE. Addr.: El Paso Building, 1001 Louisiana St., Houston, TX 77002. Tel.: (713) 420-2600. Web: www.elpaso.com.

El Paso Corporation's growth initiatives offer considerable promise. Recent acquisitions and investments continue to improve the natural gas and oil unit's long-term earnings potential. Indeed, we believe the completion of the acquisition of Peoples Energy Production Company is a solid strategic and operational fit for the company. Peoples owns roughly 305 billion cubic feet equivalent (bcfe) of proved reserves with recent production logged at 72 million cubic feet equivalent per day (mmcfe/d). In combination with El Paso's existing portfolio, the new assets will improve the predictability of future performance and add meaningfully to the company's inventory of future drilling projects.

Further investments in liquefied natural gas (LNG) augur well for long-term profitability. The company recently inked an agreement to acquire a 50% stake in the Gulf LNG Clean Energy Project, a liquefied natural gas terminal being built in Mississippi, through its subsidiary, Southern Natural Gas. Houston-based investors, The Crest Group, and an Angola-based LNG firm, Sonangol USA, are ponying up the balance (30% and 20%, respectively). The project, which received its Federal Energy Regulatory Commission certificate in February, 2007, includes the construction of two, 160,000-cubic-meter storage tanks with a combined capacity of 6.6 billion cubic feet (bcf); 10 vaporizers, providing a base send-out capacity of 1.3 bcf/d; and five miles of 36-inch pipeline, connecting the terminal to the Gulfstream, Destin, Florida Gas Transmission, and Transco pipelines. Management notes that the capacity is already fully subscribed under 20-year agreements, which eases concerns about global liquefication capacity restraints.

Volume growth and higher realized natural gas prices are boosting revenues across the board. We expect these factors to continue to propel profits, making these shares a timely choice in the year ahead.

Simon R. Shoucair *December 14, 2007*

CASH POSITION	5-Year Av'g	9/30/07
Current Assets to Current Liabilities:	88%	73%
Cash & Equiv's to Current Liabilities:	10%	14%
Working Capital to Sales:	NMF	NMF

(A) Energy trading revenues presented on a net basis beginning in '02.
(B) Average earnings through '96, then diluted. Excl. net nonrecurring items: '96, d83¢; '99, d$2.83; '00, 25¢; '01, d$3.08; '02, d$3.26; '03, d$2.82; '04, d$1.33; '05, d$1.32; '06, (6¢). Next earnings report due mid-February.
(C) Dividends historically paid in early Jan., Apr., Jul., and Oct. ■ Div'd reinvestment plan available.
(D) In mill., adjusted for split.
(E) Restated to excl. discontinued operations.

Company's Financial Strength	C++
Stock's Price Stability	15
Price Growth Persistence	15
Earnings Predictability	10

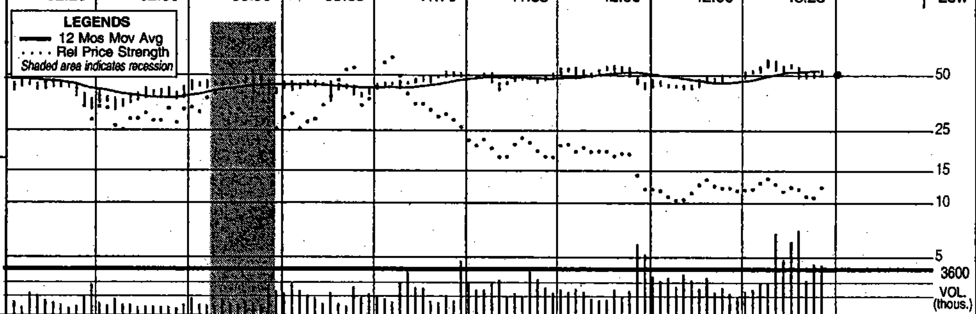
ENBRIDGE ENERGY NYSE--EEP

RECENT PRICE	TRAILING P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
51.16	21.3	1.16	7.4%	VALUE LINE

RANKS	1999	2000	2001	2002	2003	2004	2005	2006	2007	
High	48.75	43.49	49.60	46.75	52.93	51.95	57.08	50.99	61.82	High
Low	32.25	32.00	38.90	35.68	41.70	41.35	42.00	42.00	48.25	Low

PERFORMANCE 4 Below Average
Technical 3 Average
SAFETY 1 Highest
BETA .60 (1.00 = Market)

Financial Strength A
Price Stability 100
Price Growth Persistence 35
Earnings Predictability 45



© VALUE LINE PUBLISHING, INC.	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008/2009
SALES PER SH	10.82	10.57	10.33	26.67	58.59	72.60	98.80	83.88	--	
"CASH FLOW" PER SH	4.41	3.88	3.12	3.55	3.86	4.38	3.19	5.41	--	
EARNINGS PER SH	2.48	1.78	.98	1.76	1.93	2.06	.77	3.62	*2.78* [A,B]	*2.92* [C]/NA
DIV'DS DECL'D PER SH	3.49	3.50	3.50	3.63	3.70	3.70	3.70	3.70	--	
CAP'L SPENDING PER SH	2.87	.75	1.06	4.83	2.39	4.89	5.26	11.14	--	
BOOK VALUE PER SH	20.08	18.36	19.54	22.31	24.26	23.65	20.28	25.72	--	
COMMON SHS OUTST'G (MILL)	28.90	28.90	32.97	44.46	54.14	59.11	65.56	77.60	--	
AVG ANN'L P/E RATIO	17.3	21.6	45.9	24.5	24.5	23.4	67.1	12.7	*18.4*	*17.5/NA*
RELATIVE P/E RATIO	.99	1.40	2.35	1.34	1.40	1.24	3.55	.69	--	
AVG ANN'L DIV'D YIELD	8.1%	9.1%	7.8%	8.4%	7.8%	7.7%	7.2%	8.0%	--	
SALES ($MILL)	312.6	305.6	340.4	1185.5	3172.3	4291.7	6476.9	6509.0	--	*Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.*
OPERATING MARGIN	60.2%	58.1%	46.9%	18.4%	9.2%	8.3%	4.8%	8.0%	--	
DEPRECIATION ($MILL)	57.8	61.1	63.8	79.9	97.4	120.5	138.2	135.1	--	
NET PROFIT ($MILL)	78.7	60.2	38.9	78.1	111.7	138.2	71.1	284.9	--	
INCOME TAX RATE	--	--	--	--	--	--	--	--	--	
NET PROFIT MARGIN	25.2%	19.7%	11.4%	6.6%	3.5%	3.2%	1.1%	4.4%	--	
WORKING CAP'L ($MILL)	46.9	48.6	d171.3	d61.1	d179.8	69.5	14.0	47.7	--	
LONG-TERM DEBT ($MILL)	784.5	799.3	715.4	1455.5	1288.9	1701.5	1682.9	2066.1	--	
SHR. EQUITY ($MILL)	586.1	535.9	644.2	991.6	1313.3	1397.9	1363.8	2043.4	--	
RETURN ON TOTAL CAP'L	7.7%	6.8%	4.6%	4.6%	5.7%	5.9%	4.2%	8.3%	--	
RETURN ON SHR. EQUITY	13.4%	11.2%	6.0%	7.9%	8.5%	9.9%	5.2%	13.9%	--	
RETAINED TO COM EQ	NMF	NMF	NMF	NMF	NMF	NMF	NMF	2.9%	--	
ALL DIV'DS TO NET PROF	NMF	NMF	NMF	NMF	NMF	NMF	NMF	80%	--	

[A]No. of analysts changing earn. est. in last 1 days: 0 up, 0 down, consensus 5-year earnings growth 4.5% per year. [B]Based upon 11 analysts' estimates. [C]Based upon 11 analysts' estimates.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	52.0%	-15.0%
"Cash Flow"	2.5%	69.5%
Earnings	4.0%	370.0%
Dividends	1.0%	--
Book Value	3.5%	27.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/05	1250	1332	1809	2084	6476.9
12/31/06	1888	1424	1532	1663	6509.0
12/31/07	1712	1740	1710		
12/31/08					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/04	.51	.56	.38	.61	2.06
12/31/05	.37	.32	d.32	.40	.77
12/31/06	1.12	.96	1.03	.56	3.62
12/31/07	.40	.69	.75	*.74*	
12/31/08	*.68*	*.77*			

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2004	.925	.925	.925	.925	3.70
2005	.925	.925	.925	.925	3.70
2006	.925	.925	.925	.925	3.70
2007	.925	.925	.925	.95	3.73

INSTITUTIONAL DECISIONS

	4Q'06	1Q'07	2Q'07
to Buy	74	72	84
to Sell	42	48	47
Hld's(000)	11879	12768	21097

ASSETS ($mill.)	2005	2006	9/30/07
Cash Assets	89.8	184.6	149.4
Receivables	109.7	146.7	104.2
Inventory (Avg cost)	138.9	117.1	126.2
Other	646.9	560.9	444.6
Current Assets	985.3	1009.3	824.4
Property, Plant & Equip, at cost	3862.0	4731.6	--
Accum Depreciation	782.0	906.7	--
Net Property	3080.0	3824.9	5134.7
Other	363.1	389.6	394.7
Total Assets	4428.4	5223.8	6353.8
LIABILITIES ($mill.)			
Accts Payable	247.9	211.5	172.0
Debt Due	31.0	167.2	205.9
Other	692.4	582.9	635.1
Current Liab	971.3	961.6	1013.0

LONG-TERM DEBT AND EQUITY as of 9/30/07

Total Debt $2747.1 mill. **Due in 5 Yrs.** NA
LT Debt $2541.2 mill.
Including Cap. Leases NA
(49% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability None in '06 vs. None in '05

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 90,218,797 shares
(51% of Cap'l)

INDUSTRY: Oil/Gas Distribution

BUSINESS: Enbridge Energy Partners LP, through its subsidiaries, engages in the ownership and operation of crude oil, and liquid petroleum transportation and storage assets in the United States. The company's Liquids segment includes a common carrier pipeline and feeder pipeline that transport crude oil and other liquid hydrocarbons. Its Natural Gas segment operates natural gas transmission pipeline, treating plants, and processing plants. This segment also includes the transportation of natural gas liquids, crude oil, and carbon dioxide by rail and road, as well as the related rail cars, trucks, and trailers. The company's Marketing segment provides natural gas supply, transportation, storage, and sales services to producers and wholesale customers. Enbridge Energy Partners offers its services to integrated oil companies, independent oil producers, refiners, marketers, industrial facilities, local distribution companies, and shippers of natural gas. Has about 0 employees. President: Dan C. Tutcher. Inc.: DE. Address: 1100 Louisiana, Suite 3300, Houston, TX 77002. Tel.: (713) 821-2000. Internet: http://www.enbridgepartners.com.

A.Z.

December 14, 2007

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 11/30/2007

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
2.17%	-5.02%	9.45%	28.09%	88.72%

ENTERPRISE PROD. NYSE-EPD

RECENT PRICE **31.23** | P/E RATIO **29.2** (Trailing: 32.5 Median: NMF) | RELATIVE P/E RATIO **1.71** | DIV'D YLD **6.6%** | VALUE LINE

TIMELINESS 4 Lowered 11/2/07
SAFETY 3 New 12/21/01
TECHNICAL 3 Raised 11/23/07
BETA .55 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+60%)	*18%*
Low	35	(+10%)	*9%*

Insider Decisions

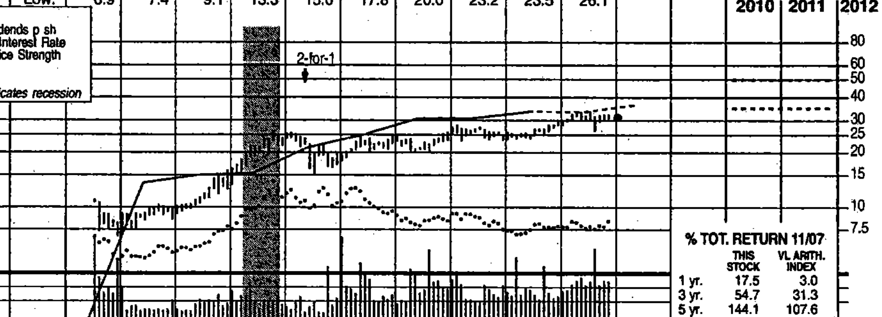
	J	F	M	A	M	J	J	A	S
to Buy	1	1	0	0	1	0	0	1	0
Options	0	0	0	0	1	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	140	136	147
to Sell	89	88	89
Hld's(000)	76968	88913	105481

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	11.0	10.3	15.9	26.3	25.8	25.0	26.0	28.3	30.0	33.7
Low:	6.9	7.4	9.1	13.3	15.0	17.8	20.0	23.2	23.5	26.1

LEGENDS
—— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/02
Options: Yes
Shaded area indicates recession



Target Price Range

2010	2011	2012

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	17.5	3.0
3 yr.	54.7	31.3
5 yr.	144.1	107.6

Enterprise Products Partners, L.P. was formed in 1968. The Partnership offered 22,500,000 limited partnership common units to the public on May 13, 1998 at a price of $11.13 per unit. The deal was underwritten by Lehman Brothers. Subsequent to the offering, the company had 100,444,444 common units and 47,208,888 subordinated units outstanding, adjusted for a stock split.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
--	5.52	9.99	18.20	18.25	20.73	24.64	22.56	31.44	32.36	*36.30*	*38.40*	Revenues per Unit	*46.05*
--	.42	1.08	1.55	1.69	1.11	1.09	1.27	2.16	2.34	*2.45*	*2.95*	"Cash Flow" per Unit	*3.70*
--	.31	.82	1.32	1.39	.54	.58	.87	.91	1.14	*.95*	*1.30*	Earnings per Unit A	*1.80*
--	.16	.90	1.05	1.16	1.33	1.44	1.54	1.66	1.80	*1.92*	*2.06*	Dist. Decl'd per Unit B	*2.84*
--	.06	.16	1.44	.86	.42	.67	.42	2.22	3.10	*3.90*	*4.00*	Cap'l Spending per Unit	*4.15*
--	4.16	5.86	5.54	6.58	6.94	7.86	14.45	14.57	14.99	*14.60*	*14.75*	Book Value per Unit	*15.15*
--	133.93	133.39	168.87	174.21	172.95	216.98	368.77	389.86	432.41	*438.00*	*440.00*	Units Outst'g C	*456.00*
--	28.2	11.1	8.8	14.7	39.2	37.5	25.9	28.4	22.8	*Bold figures are*		Avg Ann'l P/E Ratio	*24.0*
--	1.47	.63	.57	.75	2.14	2.14	1.37	1.51	1.24	*Value Line*		Relative P/E Ratio	*1.60*
--	1.8%	9.9%	9.0%	5.7%	6.3%	6.6%	6.8%	6.4%	6.9%	*estimates*		Avg Ann'l Dis't Yield	*6.6%*
--	738.9	1333.0	3073.1	3179.7	3584.8	5346.4	8321.2	12257	13991	*15900*	*16900*	Revenues ($mill)	*21000*
--	7.3%	10.8%	9.3%	10.7%	7.1%	7.5%	6.8%	8.7%	9.2%	*9.0%*	*10.0%*	Operating Margin	*10.5%*
--	19.2	25.3	41.0	51.9	86.1	115.8	198.9	420.8	448.2	*510*	*540*	Depreciation ($mill)	*660*
--	37.3	120.3	220.5	242.2	105.7	140.4	268.3	419.5	565.2	*570*	*750*	Net Profit ($mill)	*1030*
--	--	--	--	--	1.6%	4.7%	1.4%	1.9%	3.6%	*Nil*	*Nil*	Income Tax Rate	*Nil*
--	5.0%	9.0%	7.2%	7.6%	2.9%	2.6%	3.2%	3.4%	4.0%	*3.6%*	*4.4%*	Net Profit Margin	*4.9%*
--	54.9	d146.6	d5.0	109.6	d83.8	d409.7	d145.2	81.1	d62.7	*10.0*	*60.0*	Working Cap'l ($mill)	*100*
--	90.0	166.0	404.0	855.3	2231.5	1899.5	4266.2	4833.8	5295.6	*6900*	*7000*	Long-Term Debt ($mill)	*7200*
--	562.5	789.5	936.0	1146.9	1200.9	1706.0	5328.8	5679.3	6480.2	*6400*	*6500*	Partners' Capital	*6900*
--	6.8%	13.5%	17.8%	13.4%	4.6%	5.8%	3.6%	5.1%	5.8%	*5.5%*	*7.0%*	Return on Total Cap'l	*9.0%*
--	6.6%	15.2%	23.6%	21.1%	8.8%	8.2%	5.0%	7.4%	8.7%	*9.0%*	*11.5%*	Return on Partners'Cap'l	*15.0%*
--	2.8%	1.1%	8.5%	6.6%	NMF	NMF	NMF	NMF	NMF	*NMF*	*NMF*	Retained to Part.'s Cap	*NMF*
--	58%	93%	64%	69%	NMF	NMF	NMF	NMF	NMF	*NMF*	*NMF*	All Dist. to Net Prof	*NMF*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $6772.0 mill. **Due in 5 Yrs** $2429.1 mill
LT Debt $6772.0 mill. **LT Interest** $400.0 mill.
(LT interest earned: 3.5x) (52% of Cap'l)

Leases, Uncapitalized: Annual rentals $34.9 mill.

No Defined Benefit Pension Plan

Pfd Stock None

Partners'Capital 434,736,708 units
As of 11/1/07

MARKET CAP: $13.6 billion (Large Cap)

CURRENT POSITION ($MILL.)	2005	2006	9/30/07
Cash Assets	57.1	46.2	107.8
Receivables	1454.5	1323.0	1590.2
Inventory (Avg Cst)	339.6	423.8	509.9
Other	120.2	129.2	167.9
Current Assets	1971.4	1922.2	2375.8
Accts Payable	289.1	283.9	347.3
Debt Due	--	--	--
Other	1601.2	1701.0	2128.7
Current Liab.	1890.3	1984.9	2476.0

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	--	13.0%	*8.0%*
"Cash Flow"	--	6.0%	*11.5%*
Earnings	--	-3.5%	*12.0%*
Dividends	--	10.0%	*9.5%*
Book Value	--	19.5%	*1.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	1704.9	1713.3	2040.3	2862.7	8321.2
2005	2555.5	2671.8	3249.3	3780.4	12257.0
2006	3250.1	3518.0	3872.4	3350.5	13991.0
2007	3322.0	4212.8	4112.0	*4253.2*	*15900*
2008	*4050*	*4200*	*4300*	*4350*	*16900*

Calendar	EARNINGS PER UNIT A D Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	.23	.11	.21	.28	.87
2005	.25	.14	.29	.23	.91
2006	.28	.25	.35	.25	1.14
2007	.20	.26	.20	*.29*	*.95*
2008	*.28*	*.30*	*.30*	*.42*	*1.30*

Calendar	QUARTERLY DISTRIBUTIONS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.363	.363	.373	.373	1.47
2004	.373	.373	.395	.40	1.54
2005	.40	.41	.42	.43	1.66
2006	.438	.445	.453	.46	1.80
2007	.468	.475	.483	.49	

BUSINESS: Enterprise Products Partners, L.P., is one of the leading integrated providers of natural gas and natural gas liquids processing, fractionation, transportation, and storage services. Its assets are geographically focused on the U.S. Gulf Coast. Enterprise value is about $14.6 billion. Acquired GulfTerra Energy Partners 9/30/04; Acadian Gas LLC, 4/1/01; Shell's LA and MS NGL business, 8/1/99. 2006 revenues: Pipelines & Services, 89%; Petrochemical Services, 11%. 2006 depr. rate: 4.0%. Has about 3000 employees. Mgmt. & Affl. owns 36% of the units (3/31 prospectus). Chrmn.: Dan L. Duncan. Pres. & CEO: Michael A. Creel. Org.: TX. Addr.: 100 Louisiana Street, Houston, TX 77002. Tel.: (713) 381-6500. Web: www.epplp.com.

Enterprise Products Partners reported mixed results for the September quarter. Total revenue advanced about 6% during the period, compared to a year ago. However, bottom-line results declined dramatically, owing to higher depreciation expense associated with newly acquired and expanded assets. Interest costs also increased due to a rising long-term debt level. Moreover, results were hurt by start-up and maintenance costs from recently completed projects.

The NGL Pipelines & Services segment has weakened a bit. This unit, which accounts for about 52% of operating profit, reported an 18% decline in income during the quarter. The sluggishness was largely due to lower NGL marketing revenue and reduced propane import volumes. Some of this weakness was offset by a 21% increase in profits at the Offshore Pipeline & Services segment, which accounts for about 13% of income.

The Partnership's finances remain adequate, despite increased leverage. Long-term debt rose to $6.7 billion during the September quarter, compared with $5.0 billion a year ago. Nonetheless, the debt-to-capital level was about 52% at the end of the quarter, which is reasonable. Also, about 80% of the debt is at a fixed rate of interest, providing some protection against rising rates.

We are lowering our earnings estimate for 2007 by $0.25 per unit, and reducing our 2008 estimate, as well. This reflects higher costs, as well as the ongoing issuance of units. Capital spending has been about $1.6 billion so far in 2007, and will probably increase a bit in 2008. The completion of some large projects should help results. Enterprise currently has about $2.1 billion in assets in several stages of development. A considerable amount of capital is devoted to projects in the Rocky Mountains region and the Gulf of Mexico.

These limited partnership units are ranked to underperform the year-ahead market. However, our projections indicate that this issue offers worthwhile total return potential for the 3- to 5-year horizon. The recent 1.4% increase in the quarterly dividend improves the yield a bit, with more hikes likely.

Adam Rosner *December 14, 2007*

(A) Diluted earnings per unit of limited partnership. Excl. nonrecur. gain: '06, $0.08. Next earnings report due late Jan.
(B) Distributions historically paid in mid February, May, August, November.
(C) In millions, adjusted for split.
(D) Quarters may not sum due to change in shares outstanding.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	60

KINDER MORGAN EN. NYSE-KMP

RECENT PRICE **51.41** | P/E RATIO **26.1** (Trailing: 30.1 Median: 19.0) | RELATIVE P/E RATIO **1.53** | DIV'D YLD **6.8%** | VALUE LINE

TIMELINESS	4	Lowered 9/2/05
SAFETY	2	Raised 9/17/04
TECHNICAL	3	Raised 12/7/07

BETA .65 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+5%)	9%
Low	40	(-20%)	3%

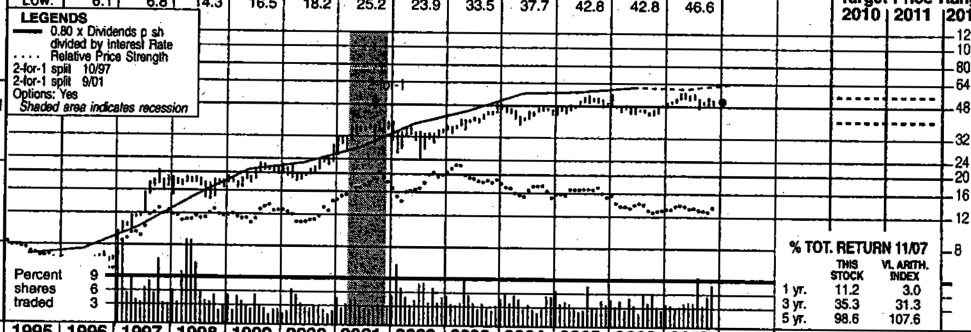
Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	141	151	140
to Sell	130	116	109
Hld's(000)	30405	33528	37663

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	7.3	20.6	19.1	22.8	28.9	39.7	38.9	49.9	49.1	55.2	56.2	57.3
Low:	6.1	6.8	14.3	16.5	18.2	25.2	23.9	33.5	37.7	42.8	42.8	46.6



Target Price Range
2010 | 2011 | 2012

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	11.2	3.0
3 yr.	35.3	31.3
5 yr.	98.6	107.6

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
2.35	1.03	2.23	2.30	2.47	2.74	2.76	3.30	3.63	6.05	17.77	23.42	35.04	38.32	44.44	39.87	**39.10**	**40.15**	Revenues per Unit	**46.45**
.77	.39	.69	.83	.79	.83	.95	1.30	1.43	2.00	2.38	2.84	3.17	3.52	3.88	3.76	**5.25**	**5.85**	"Cash Flow" per Unit	**7.40**
.49	.25	.38	.47	.43	.45	.51	1.05	1.22	1.34	1.56	1.96	2.00	2.22	2.37	1.98	**1.70**	**2.05**	Earnings per Unit A	**3.00**
--	.08	.55	.63	.63	.63	.81	1.19	1.39	1.60	2.08	2.36	2.58	2.81	3.07	3.26	**3.44**	**3.65**	Dist. Decl'd per Unit B	**4.40**
1.45	.07	.21	.22	.30	.33	.26	.39	.70	.93	1.78	3.00	3.05	3.61	3.92	4.71	**6.85**	**7.10**	Cap'l Spending per Unit	**7.25**
4.92	6.06	5.80	5.42	4.68	4.50	5.47	13.81	14.87	15.43	18.72	18.48	18.13	18.32	15.86	17.42	**18.65**	**19.50**	Book Value per Unit	**23.60**
22.60	22.60	22.60	23.46	26.04	26.04	26.82	97.63	118.27	135.03	165.80	180.91	189.04	207.01	220.24	224.62	**235.00**	**245.00**	Units Outst'g C	**255.00**
--	25.4	19.0	15.3	14.9	14.7	27.0	16.8	16.1	16.0	21.8	17.0	20.1	20.0	20.7	22.8	*Bold figures are*		Avg Ann'l P/E Ratio	**16.5**
--	1.54	1.12	1.00	1.00	.92	1.56	.87	.92	1.04	1.12	.93	1.15	1.06	1.10	1.23	*Value Line*		Relative P/E Ratio	**1.10**
--	1.3%	7.7%	8.8%	9.9%	9.6%	5.9%	6.8%	7.1%	7.5%	6.1%	7.1%	6.4%	6.3%	6.3%	7.0%	*estimates*		Avg Ann'l Dist. Yield	**8.9%**
						73.9	322.6	428.8	816.4	2946.7	4237.1	6624.3	7932.9	9787.1	8954.6	**9185**	**9835**	Revenues ($mill)	**11850**
						50.4%	54.9%	53.6%	48.8%	24.0%	21.2%	15.5%	15.9%	13.9%	18.6%	**16.5%**	**17.5%**	Operating Margin	**18.5%**
						10.1	37.3	46.5	82.6	142.1	172.0	219.0	288.6	349.8	413.7	**510**	**520**	Depreciation ($mill)	**540**
						17.7	117.2	175.3	278.3	442.3	608.4	693.9	831.6	982.3	972.1	**730**	**915**	Net Profit ($mill)	**1345**
						--	1.3%	5.1%	4.8%	3.6%	2.5%	2.3%	2.3%	2.4%	1.9%	**3.0%**	**3.0%**	Income Tax Rate	**3.0%**
						24.0%	36.3%	40.9%	34.1%	15.0%	14.4%	10.5%	10.5%	10.0%	10.9%	**7.9%**	**9.3%**	Net Profit Margin	**11.4%**
						10.4	d7.6	d187.3	d587.7	d394.7	d143.9	d98.9	d327.7	d593.7	d1849.0	**d1545**	**d1385**	Working Cap'l ($mill)	**d2250**
						146.8	580.1	989.1	1255.5	2231.6	3659.5	4438.1	4852.6	5319.4	4427.0	**6350**	**7500**	Long-Term Debt ($mill)	**8750**
						150.2	1360.7	1774.8	2117.1	3159.0	3415.9	3510.9	3896.5	3613.7	4021.7	**4385**	**4775**	Partners' Capital	**6015**
						8.1%	7.0%	7.3%	9.6%	9.5%	9.8%	9.8%	10.5%	12.2%	12.7%	**7.0%**	**7.5%**	Return on Total Cap'l	**9.0%**
						11.8%	8.6%	9.9%	13.1%	14.0%	17.8%	19.8%	21.3%	27.2%	24.2%	**16.5%**	**19.0%**	Return on Partners'Cap'l	**22.5%**
						NMF	NMF	NMF	NMF	NMF	1.1%	.4%	1.3%	1.3%	NMF	**NMF**	**NMF**	Retained to Part.'s Cap	**NMF**
						NMF	103%	108%	103%	104%	94%	98%	94%	95%	NMF	**NMF**	**NMF**	All Dist. to Net Prof	**NMF**

CAPITAL STRUCTURE as of 9/30/07
Total Debt $7099.0 mill. **Due in 5 Yrs** $2585 mill.
LT Debt $6502.0 mill. **LT Interest** $185 mill.
(LT interest earned: 6.0x) (59% of Cap'l)
Leases, Uncapitalized: Annual rentals $47.7 mill.
No Defined Benefit Pension Plan

Partners' Capital: 231,759,554 units
163,090,396 publicly held common units as of 10/31/07
68,669,158 class B and I units
(Class B units are held entirely by KMI
I-Units owned by KMR and are not traded)
MARKET CAP: $11.9 billion (Large Cap)

CURRENT POSITION ($MILL.)	2005	2006	9/30/07
Cash Assets	12.1	14.0	58.4
Receivables	1014.3	859.6	847.3
Inventory (Avg Cst)	32.1	34.2	34.3
Other	156.7	128.9	116.9
Current Assets	1215.2	1036.7	1056.9
Accts Payable	1043.3	804.5	824.9
Debt Due	--	1359.1	597.0
Other	765.6	722.1	829.0
Current Liab.	1808.9	2885.7	2250.9

ANNUAL RATES of change (per unit)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	32.0%	35.0%	2.0%
"Cash Flow"	16.5%	14.0%	12.0%
Earnings	17.5%	10.0%	5.0%
Distributions	17.0%	12.5%	6.5%
Book Value	13.5%	1.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	1822	1957	2014	2138	7932.9
2005	1971	2126	2631	3057	9787.1
2006	2391	2196	2273	2093	8954.6
2007	2152	2380	2231	**2422**	**9185**
2008	**2385**	**2460**	**2470**	**2520**	**9835**

Cal-endar	EARNINGS PER UNIT A D Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2004	.52	.51	.59	.60	2.22
2005	.68	.50	.57	.59	2.37
2006	.53	.50	.40	.55	1.98
2007	.33	.36	.43	**.58**	**1.70**
2008	**.46**	**.50**	**.53**	**.56**	**2.05**

Cal-endar	QUARTERLY DISTRIBUTIONS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.625	.64	.65	.66	2.58
2004	.68	.69	.71	.73	2.81
2005	.74	.76	.78	.79	3.07
2006	.81	.81	.81	.83	3.26
2007	.83	.83	.85	.88	

BUSINESS: Kinder Morgan Energy Partners, L.P., is the nation's largest pipeline master limited partnership. It owns about 26,000 miles of pipelines and 150 terminals. Pipelines transport over two mill. barrels per day of petroleum products, and up to 8.4 bill. cubic feet per day of natural gas. CO2 segment transports over 1 bill. cubic feet per day of CO2; Terminals handle more than 90 mill. tons annually. 2006 oper. inc.: products pipelines, 25%; gas pipelines, 29%; CO2, 25%; bulk terminals, 21%. Depr. rate: 3.5%. Apr. 8,600 employees. Knight (formerly Kinder Morgan, Inc.) owns 14.7% of the units ('06 10K). Chairman & CEO of general partner: Richard D. Kinder. Organized: DE. Address: 500 Dallas Street; Houston, TX, 77002. Tel.: 713-369-9000. Internet: www.kindermorgan.com.

Kinder Morgan Energy Partners is coming back on track . . . The partnership struggled during much of the first half of the year, and posted dismal comparisons mainly due to weakness in its CO2 and Terminals segments. Profits from both of these segments have recovered nicely, and were up 9% and 11%, respectively from their year-ago figures during the September period. This, in fact, helped share net advance almost 8% during the interim. Too, some of management's efforts began to take hold during the interim. Although we expect that these initiatives will continue to gain momentum over the next few quarters, the slow start may cause the bottom line to decline in 2007.

. . . with several projects under way. Kinder has been aggressively pursuing expansion ventures. The EPX project, which is designed to extend its Texas and Arizona pipeline infrastructure, is now coming on line. Construction on the Rockies Express Pipeline is in full swing, too, and should allow producers in the region to boost output significantly over the next five years. Likewise, management expects that Barnett Shale output will more than double by the end of the decade, increasing takeaway potential. Kinder ought to renew its focus on its LNG terminals over the next few months, as well. In addition to these projects, the partnership has been building its portfolio with the recent purchase of Marine Terminals in an effort to improve its storage network. And it ought to find other ways to help fuel top- and bottom-line growth.

Capital spending is rising. Although Kinder remains heavily dependent on its cash flow to fund these projects, the partnership has taken on significant debt over the past few months. Further, it may increase its borrowings to finance future expansions and developments.

Income-oriented investors may want to take note of this issue. Management has been steadily raising its quarterly distribution over the past decade. Moreover, it increased its latest payout 9% from a year ago. But caveat emptor, these shares are ranked to trail the broader marker averages in the coming year, and are already trading within our projected 3- to 5-year Target Price Range.

Orly Seidman *December 14, 2007*

(A) Primary earnings per unit of limited partnership interest. Excl. nonrec. items: '99: 14¢; '02: 2¢; '05: 12¢. Next egs. report due late Jan.
(B) Distribution payment dates: mid-Feb., May, Aug., and Nov. Holders are not taxed on cash distributions, but on their proportional shares of KMP's taxable income. In the first year of ownership, a limited partner's taxable income is about 10% of the year's cash distribution.
(C) In millions, adjusted for splits.
(D) 2004 and 2005 Qtly. egs do not sum due to changes in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	85

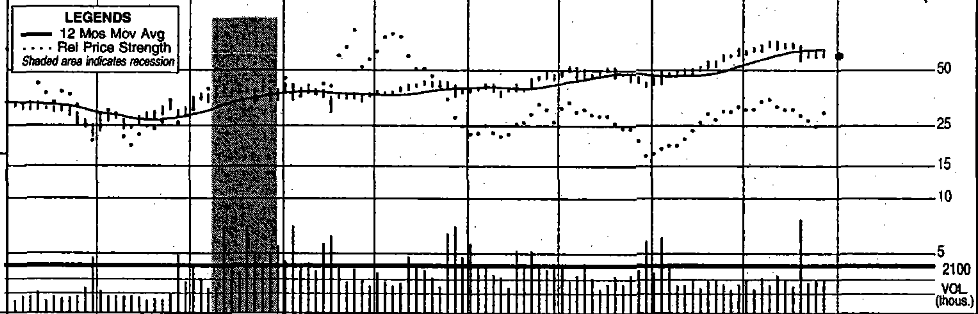
ONEOK PARTNERS NYSE-OKS

RECENT PRICE 60.38 | TRAILING P/E RATIO 19.4 | RELATIVE P/E RATIO 1.06 | DIV'D YLD 6.7% | VALUE LINE

RANKS

PERFORMANCE	3	Average
Technical	3	Average
SAFETY	1	Highest
BETA .65		(1.00 = Market)

		1999	2000	2001	2002	2003	2004	2005	2006	2007	
High		35.50	33.62	41.20	42.50	44.07	49.54	52.99	66.74	73.00	High
Low		21.63	23.06	30.25	29.30	35.98	35.70	40.60	41.54	56.00	Low



Financial Strength	A
Price Stability	95
Price Growth Persistence	65
Earnings Predictability	5

© VALUE LINE PUBLISHING, INC.	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008/2009
SALES PER SH	10.87	10.78	11.09	11.31	11.98	12.72	14.63	56.87	--	
"CASH FLOW" PER SH	4.56	4.37	3.98	4.34	d.20	4.92	5.02	5.94	--	
EARNINGS PER SH	2.70	2.50	2.15	2.44	d2.16	2.81	2.92	4.00	*NA*	*NA/NA*
DIV'DS DECL'D PER SH	2.44	2.65	2.99	3.20	3.20	3.20	3.20	3.60	--	
CAP'L SPENDING PER SH	3.48	.63	3.04	1.14	.65	.94	1.29	2.43	--	
BOOK VALUE PER SH	17.21	18.17	21.98	21.55	17.25	17.01	16.50	26.40	--	
COMMON SHS OUTST'G (MILL)	29.35	31.50	41.62	43.81	46.40	46.40	46.40	82.89	--	
AVG ANN'L P/E RATIO	11.1	11.2	17.5	15.4	--	14.9	16.4	13.2	*NA*	*NA/NA*
RELATIVE P/E RATIO	.63	.73	.90	.84	--	.79	.87	.71	--	
AVG ANN'L DIV'D YIELD	8.2%	9.5%	8.0%	8.5%	7.9%	7.6%	6.7%	6.8%	--	
SALES ($MILL)	319.0	339.7	461.5	495.6	555.9	590.4	678.6	4714.0	--	*Bold figures*
OPERATING MARGIN	83.2%	81.8%	70.6%	67.3%	23.4%	63.8%	56.3%	11.0%	--	*are consensus*
DEPRECIATION ($MILL)	54.5	61.1	76.7	76.2	82.9	87.2	86.4	122.0	--	*earnings*
NET PROFIT ($MILL)	81.0	76.7	89.0	113.7	d92.0	140.9	146.5	370.5	--	*estimates*
INCOME TAX RATE	--	--	--	--	--	3.5%	3.8%	--	--	*and, using the*
NET PROFIT MARGIN	25.4%	22.6%	19.3%	22.9%	NMF	23.9%	21.6%	7.9%	--	*recent prices,*
WORKING CAP'L ($MILL)	d177.8	d47.0	d362.2	d71.3	7.3	28.0	27.4	22.2	--	*P/E ratios.*
LONG-TERM DEBT ($MILL)	848.4	1127.5	1070.8	1336.0	1408.2	1325.2	1352.8	2019.6	--	
SHR. EQUITY ($MILL)	515.3	572.3	915.0	944.0	800.6	789.3	765.6	2188.7	--	
RETURN ON TOTAL CAP'L	8.4%	6.9%	6.8%	6.8%	NMF	8.5%	9.0%	10.4%	--	
RETURN ON SHR. EQUITY	15.7%	13.4%	9.7%	12.0%	NMF	17.9%	19.1%	16.9%	--	
RETAINED TO COM EQ	1.6%	NMF	NMF	NMF	NMF	NMF	NMF	4.8%	--	
ALL DIV'DS TO NET PROF	90%	105%	NMF	NMF	NMF	113%	109%	72%	--	

Note: No analyst estimates available.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	21.0%	289.0%
"Cash Flow"	4.0%	18.5%
Earnings	6.0%	37.0%
Dividends	4.5%	12.5%
Book Value	1.0%	60.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/05	160.4	149.4	183.1	185.7	678.6
12/31/06	1169	1159	1214	1170	4714.0
12/31/07	1161	2871	1410		
12/31/08					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/04	.73	.66	.69	.73	2.81
12/31/05	.68	.54	.99	.71	2.92
12/31/06	.67	1.47	1.04	.82	4.00
12/31/07	1.00	.31	.98		
12/31/08					

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2004	.80	.80	.80	.80	3.20
2005	.80	.80	.80	.80	3.20
2006	.80	.88	.95	.97	3.60
2007	.98	.99	1.00	1.01	3.98

INSTITUTIONAL DECISIONS

	4Q'05	4Q'06	2Q'07
to Buy	45	--	--
to Sell	50	--	--
Hld's(000)	8450	--	--

ASSETS ($mill.)	2005	2006	9/30/07
Cash Assets	43.1	21.1	794.4
Receivables	81.5	298.6	424.6
Inventory	7.3	13.1	227.5
Other	6.5	474.1	67.1
Current Assets	138.4	806.9	1513.6
Property, Plant & Equip, at cost	3000.7	3424.5	--
Accum Depreciation	1082.2	660.9	--
Net Property	1918.5	2763.6	3099.3
Other	470.9	1464.9	1452.0
Total Assets	2527.8	5035.4	6064.9
LIABILITIES ($mill.)			
Accts Payable	46.6	362.0	508.8
Debt Due	2.2	17.9	376.9
Other	62.2	404.8	343.8
Current Liab	111.0	784.7	1229.5

LONG-TERM DEBT AND EQUITY as of 9/30/07

Total Debt $2984.8 mill. **Due in 5 Yrs.** NA
LT Debt $2607.9 mill.
Including Cap. Leases NA
(54% of Cap'l)

Leases, Uncapitalized Annual rentals NA

Pension Liability None in '06 vs. None in '05

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 82,891,340 shares
(46% of Cap'l)

INDUSTRY: Natural Gas (Div.)

BUSINESS: ONEOK Partners, L.P. engages in gathering, processing, storing, and transporting natural gas in the United States. It operates through four segments: Gathering and Processing, Natural Gas Liquids, Pipelines and Storage, and Interstate Natural Gas Pipelines. The Gathering and Processing segment primarily gathers and processes raw natural gas. The Natural Gas Liquids segment principally treats and fractionates raw natural gas liquids and stores and markets purity natural gas liquids products. The Pipelines and Storage segment operates intrastate natural gas transmission pipelines, natural gas storage facilities, and regulated natural gas liquids gathering and distribution pipelines. The Interstate Natural Gas Pipelines segment operates interstate natural gas transmission pipelines. ONEOK Partners GP serves as general partner of the partnership. Has 1219 employees. C.E.O. & President: John W. Gibson . Inc.: DE. Address: 100 West Fifth Street, Tulsa, OK 74103-4298. Tel.: (402) 492-7300. Internet: http://www.oneokpartners.com.

A.T.

December 14, 2007

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 11/30/2007

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
-4.60%	-9.80%	5.67%	54.04%	136.38%

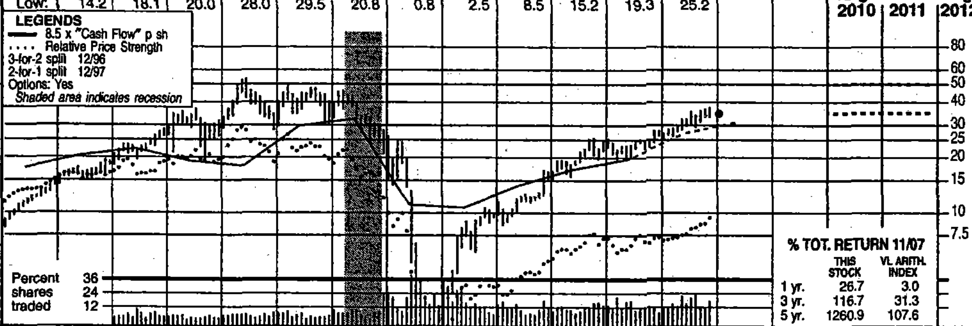
WILLIAMS COS. NYSE-WMB

RECENT PRICE	34.83	P/E RATIO	22.9 (Trailing: 28.5 Median: 30.0)	RELATIVE P/E RATIO	1.34	DIV'D YLD	1.3%	VALUE LINE

TIMELINESS 1 Raised 9/7/07
SAFETY 3 Raised 12/14/07
TECHNICAL 2 Raised 12/14/07
BETA 1.35 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	19.5	28.7	36.9	53.8	49.8	46.4	26.3	10.7	17.2	25.7	28.3	37.7
Low:	14.2	18.1	20.0	28.0	29.5	20.8	0.8	2.5	8.5	15.2	19.3	25.2

Target Price Range
2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+45%)	11%
Low	35	(Nil)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	2	8	7	2	2	2	3	0	0
to Sell	0	3	5	2	2	3	4	1	1

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	247	220	220
to Sell	215	249	222
Hld's(000)	450185	459884	470232

% TOT. RETURN 11/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	26.7	3.0
3 yr.	116.7	31.3
5 yr.	1260.9	107.6

1991	1992	1993	1994	1995	1996	1997	1998	1999	D2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
8.40	8.84	7.88	6.52	9.17	11.21	13.77	17.88	19.50	23.40	21.41	10.85	32.48	22.33	21.95	19.78	*18.65*	*20.75*	Revenues per sh	*26.00*
1.08	1.08	1.19	1.14	2.07	2.40	2.63	2.25	2.12	3.50	3.83	1.30	1.26	1.67	2.04	2.32	*3.20*	*3.70*	"Cash Flow" per sh	*5.20*
.39	.42	.53	.51	.89	1.07	1.05	.74	.39	1.64	2.35	d.16	.02	.49	.72	.86	*1.35*	*1.60*	Earnings per sh A	*2.50*
.23	.25	.26	.28	.36	.47	.54	.60	.60	.60	.68	.42	.04	.08	.25	.35	*.39*	*.45*	Div'ds Decl'd per sh B	*.65*
1.27	2.12	1.71	1.74	2.66	2.60	3.63	3.99	7.97	11.04	3.73	3.53	1.85	1.41	2.27	4.20	*4.90*	*4.60*	Cap'l Spending per sh	*6.30*
4.27	4.58	5.25	5.23	9.68	10.35	10.71	9.70	12.67	13.26	11.72	9.25	7.92	8.88	9.47	10.17	*11.60*	*12.85*	Book Value per sh	*16.25*
250.53	276.87	309.24	268.68	311.29	314.95	320.19	428.30	440.70	444.30	515.50	516.73	518.23	558.00	573.40	597.10	*587.00*	*579.00*	Common Shs Outst'g C	*615.00*
14.0	13.8	16.2	18.3	13.0	15.7	21.9	40.7	NMF	25.1	14.8	--	NMF	24.2	27.7	27.4	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.89	.84	.96	1.20	.87	.98	1.26	2.12	NMF	1.63	.76	--	NMF	1.28	1.47	1.48	*Value Line*		Relative P/E Ratio	*1.15*
4.3%	4.4%	3.0%	3.0%	3.1%	2.8%	2.3%	2.0%	1.5%	1.5%	2.0%	4.0%	.6%	.7%	1.3%	1.5%	*estimates*		Avg Ann'l Div'd Yield	*1.5%*
						4409.6	7658.3	8593.1	10398	11035	5608.4	16834	12461	12584	11813	*10950*	*12000*	Revenues ($mill)	*16000*
						31.2%	21.8%	19.5%	26.7%	31.8%	35.8%	11.5%	16.2%	16.9%	19.1%	*22.0%*	*23.5%*	Operating Margin	*28.5%*
						499.5	646.3	742.0	831.9	797.7	775.1	671.2	668.5	740.0	865.5	*1070*	*1185*	Depreciation ($mill)	*1650*
						353.9	325.4	194.9	725.3	1175.2	d83.9	12.0	261.5	427.8	520.3	*820*	*955*	Net Profit ($mill)	*1540*
						33.7%	41.4%	50.0%	38.8%	43.0%	--	70.5%	58.5%	40.3%	38.3%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
						8.0%	4.2%	2.3%	7.0%	10.7%	NMF	.1%	2.1%	3.4%	4.4%	*7.5%*	*8.0%*	Net Profit Margin	*9.6%*
						d771.5	d907.1	744.4	d1327	d556.5	1577.6	2524.9	897.7	1247.1	1628.4	*1000*	*1250*	Working Cap'l ($mill)	*1400*
						4565.3	6366.4	9235.3	10342	9500.7	11896	11040	7711.9	7590.5	7622.0	*7400*	*7330*	Long-Term Debt ($mill)	*7000*
						3571.7	4257.4	5585.2	5892.0	6044.0	5049.0	4102.1	4955.9	5427.5	6073.2	*6800*	*7450*	Shr. Equity ($mill)	*10000*
						6.3%	4.9%	3.2%	7.2%	9.8%	2.2%	2.3%	5.2%	5.8%	6.2%	*7.5%*	*8.0%*	Return on Total Cap'l	*10.5%*
						9.9%	7.6%	3.5%	12.3%	19.4%	NMF	.3%	5.3%	7.9%	8.6%	*12.0%*	*13.0%*	Return on Shr. Equity	*15.5%*
						5.0%	1.5%	NMF	7.8%	13.8%	NMF	NMF	4.4%	5.2%	5.2%	*8.5%*	*9.5%*	Retained to Com Eq	*11.5%*
						51%	80%	NMF	37%	29%	NMF	NMF	17%	33%	40%	*28%*	*27%*	All Div'ds to Net Prof	*26%*

CAPITAL STRUCTURE as of 9/30/07
Total Debt $7890.2 mill. **Due in 5 Yrs** $2070.0 mill.
LT Debt $7424.6 mill. **LT Interest** $440.0 mill.
(Total interest coverage: 2.3x)
(54% of Cap'l)

Leases, Uncapitalized $225.4 mill.

Pension Assets-12/06 $1005.3 mill.
Oblig. $931.3 mill.

Pfd Stock None

Common Stock 593,526,517 shs.
as of 10/30/07
MARKET CAP: $20.7 billion (Large Cap)

CURRENT POSITION ($MILL.)	2005	2006	9/30/07
Cash Assets	1597.2	2268.6	1455.4
Receivables	1613.8	1212.9	955.1
Inventory (Avg Cst)	272.6	241.4	214.5
Other	6213.7	2599.1	3661.2
Current Assets	9697.3	6322.0	6286.2
Accts Payable	1360.6	1148.5	1020.5
Debt Due	122.6	392.1	465.6
Other	6967.0	3153.0	3816.6
Current Liab.	8450.2	4693.6	5302.7

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	9.0%	--	*3.5%*
"Cash Flow"	.5%	-8.5%	*17.0%*
Earnings	-1.5%	-14.0%	*24.0%*
Dividends	-5.0%	-18.5%	*19.0%*
Book Value	1.0%	-5.5%	*9.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	3070.0	3051.9	3375.2	2964.2	12461.3
2005	2954.0	2871.2	3082.3	3676.1	12583.6
2006	3027.5	2715.1	3300.0	2770.3	11812.9
2007	2368.3	2823.4	2860.1	*2898.2*	*10950*
2008	*2500*	*2900*	*3300*	*3300*	*12000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.01	.10	.26	.12	.49
2005	.33	.11	d.01	.28	E.72
2006	.23	.19	.19	.26	E.86
2007	.27	.36	.36	*.36*	*1.35*
2008	*.40*	*.40*	*.40*	*.40*	*1.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.01	.01	.01	.01	.04
2004	.01	.01	.01	.05	.08
2005	.05	.05	.075	.075	.25
2006	.075	.09	.09	.09	.35
2007	.09	.10	.10	.10	

BUSINESS: The Williams Companies gathers, processes, and transports natural gas throughout the United States. It also performs gas marketing services. Acquired Barrett Resources, 8/01; MAPCO, 3/98; remaining 40% stake in Transco Energy, 5/95; and others. Sold Texas Gas Pipeline, 5/03; Kern River Pipeline, 3/02; and others. Spun off Williams Communications, 4/01. Initial public offering for Williams Partners L.P., 8/05. Has around 4,315 employees at present. Officers and directors own approximately 1.1% of common shares (4/07 Proxy). Chairman, Chief Executive Officer, and President: Steve Malcolm. Incorporated: Delaware. Address: One Williams Center, Tulsa, Oklahoma 74172. Telephone: 918-573-2000. Internet: www.williams.com.

Earnings for The Williams Companies have risen substantially in 2007, compared to the previous year. The Exploration & Production unit is enjoying much higher output (supported by further drilling efforts within the Piceance Basin in Colorado), plus favorable net realized average prices for natural gas. Results for the Midstream operation are being boosted by robust margins for natural gas liquids, while the Gas Pipeline segment is benefiting from higher rates for the two interstate transmission systems, Northwest Pipeline and Transco (which was expanded recently). All told, 2007 share net may jump about 57%, to $1.35. Additional growth in operating margins ought to enable the bottom line to climb another 18%, to $1.60 a share, in the new year.

Meanwhile, management sold most of the assets of the Power operation to The Bear Stearns Companies for $496 million (largely offset by income taxes and the resolution of retained liabilities). We applaud this move partly because it eliminates about $2.4 billion of imputed debt and related interest associated with around $400 million in annual demand obligations. Furthermore, corporate earnings ought to be more consistent, given the absence of mark-to-market effects from energy-trading activities. Lastly, more resources are freed up for the bread-and-butter natural gas businesses. (Note that our presentation reflects that unit as discontinued.)

The company's Financial Strength rating was raised one notch, to B+, arising partly from the healthy results of late and the aforementioned divestiture. Moreover, there is currently about $1.5 billion in cash on hand, which can be used for such initiatives as reinvesting in capital assets, buying back stock, and boosting the dividend.

These shares continue to be ranked 1 (Highest) for Timeliness. That's because of the good recent stock price and earnings momentum.

But at the present quotation, long-term appreciation potential is below the *Value Line* median. Other factors to take into account are the higher-than-market beta coefficient and fairly low Price Stability rating.

Frederick L. Harris, III December 14, 2007

(A) Primary thru '96, then diluted. Excl. nonrec. gains (losses): '93, 36¢; '95, $6.73; '96, 4¢, '97, 22¢; '98, (14¢); '99, 6¢; '00, 20¢; '01, (68¢); '02, (95¢); '03, ($1.54); '04, (31¢); '05, (19¢); '06, (31¢); Q1 '07, 1¢; Q2, 4¢; Q3, 2¢. Excl. gains (losses) fr. disc. op.: '00, (68¢); '01, ($2.62); '02, (49¢); '03, 49¢; '04, 13¢; '06, (4¢); '07, 20¢. '94 restat. for Wiltel sale. Next earnings report due early Feb. (B) Dividends historically paid in late Mar., Jun., Sep., and Dec. (C) In mill., adj. for splits. (D) '00 fig. excl. Solutions. (E) Qtrs don't add due to rounding.

Company's Financial Strength	B+
Stock's Price Stability	30
Price Growth Persistence	20
Earnings Predictability	15

Exhibit No. SPC-24
Docket No. RP08-__-000
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<< Back

ONEOK Partners, L.P. Is New Name for Northern Border Partners; Partnership Also Announces Governance Changes

TULSA, Okla., May 17 /PRNewswire-FirstCall/ -- Northern Border Partners, L.P. (NYSE: NBP), announced today that it will change its name to ONEOK Partners, L.P. and will begin trading under the new symbol "OKS" on the New York Stock Exchange when trading opens on Monday, May 22, 2006. In addition, ONEOK Partners announced several changes in its governance.

ONEOK, Inc. (NYSE: OKE) owns the general partner of ONEOK Partners and 45.7 percent of the partnership. In April 2006, ONEOK Partners purchased from ONEOK the gathering and processing, natural gas liquids and pipelines and storage segments for approximately $3 billion. In exchange, ONEOK received cash and limited partner units.

"The new name launches a new era for the partnership and reflects its broader scope of operations, which now include assets from ONEOK," said David Kyle, ONEOK Partners chairman and chief executive officer. "The ONEOK Partners name also acknowledges the new ownership and management structure of the partnership, the aligned interests of the partnership and ONEOK and their combined commitment to deliver growth to unit holders and shareholders of both entities."

As a result of the governance changes approved today, the current policy and audit committees will be replaced with a board of directors of ONEOK Partners GP, the sole general partner of ONEOK Partners. The board will consist of six members, three of whom are independent. The three independent members of the ONEOK Partners' board will also serve as the audit committee.

The independent directors are: Gerald B. Smith, chairman, chief executive officer and co-founder of Graham and Company Investment Advisors; Gary N. Petersen, president of Endres Processing LLC; and Gil J. Van Lunsen, retired managing partner of KPMG LLP.

Other ONEOK Partners directors are: David Kyle, ONEOK Partners chairman and chief executive officer; John W. Gibson, president and chief operating officer; and James C. Kneale, executive vice president and chief financial officer. In addition, ONEOK Partners will be headquartered in Tulsa, Okla.

As part of the name change, ONEOK Partners plans a re-branding campaign that will include employee, customer and investor communications, a new corporate identity and the launch of a re-designed Web site, http://www.oneokpartners.com , which will feature investor and customer information for ONEOK Partners, L.P. and ONEOK, Inc. on the same site. The new Web site will be launched on Monday, May 22, 2006. The new ONEOK Partners logo is available at http://www.oneok.com .

ONEOK, Inc. (NYSE: OKE) is a diversified energy company. We are the general partner and own 45.7 percent of ONEOK Partners (NYSE: OKS), one of the largest publicly traded limited partnerships, which is a leader in the gathering, processing, storage and transportation of natural gas in the U.S. and owns one of the nation's premier natural gas liquids (NGL) systems, connecting much of the natural gas and NGL supply in the mid-continent with key market centers. ONEOK is among the largest natural gas distributors in the United States, serving more than 2 million customers in Oklahoma, Kansas and Texas. Our energy services operation focuses primarily on marketing natural gas and related services throughout the U.S. ONEOK is a Fortune 500 company.

For information about ONEOK, Inc. visit the Web site: http://www.oneok.com .

Some of the statements contained and incorporated in this press release are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The forward-looking statements relate to: anticipated financial performance; management's plans and objectives for future operations; business prospects; outcome of regulatory and legal proceedings; market conditions and other matters. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances.

ONEOK, Inc.
Analyst Contact: Dan Harrison
918-588-7950
Media Contact: Megan Washbourne
918-588-7572

Northern Border Partners, L.P.
Analyst Contact: Ellen Konsdorf
877-208-7318
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402-492-3400

SOURCE ONEOK, Inc.; Northern Border Partners, L.P.
CONTACT: analysts, Dan Harrison, +1-918-588-7950, or media, Megan Washbourne, +1-918-588-7572, both of ONEOK, Inc.; or analysts, Ellen Konsdorf, +1-877-208-7318, or media, Beth Jensen, +1-402-492-3400, both of Northern Border Partners, L.P./
Web site: http://www.oneok.com
http://www.oneokpartners.com /

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995: Statements in this press release regarding ONEOK Partners, L.P.'s business which are not historical facts are "forward-looking statements" that involve risks and uncertainties. For a discussion of such risks and uncertainties, which could cause actual results to differ from those contained in the forward-looking statements, see "Risk Factors" in the Company's Annual Report or Form 10-K for the most recently ended fiscal year.

El Paso Corporation
2007 Form 10-K

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to .

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0568816** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Telephone Number: (713) 420-2600
Internet Website: www.elpaso.com
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, par value $3 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐ .

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑ .

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐ .

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant.

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of June 29, 2007 computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $12,068,373,398.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value $3 per share. Shares outstanding on February 22, 2008: 700,784,034

Documents Incorporated by Reference

List hereunder the following documents if incorporated by reference and the part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: Portions of our definitive proxy statement for the 2008 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2008.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑ .

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant.

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of June 29, 2007 computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $12,068,373,398.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value $3 per share. Shares outstanding on February 22, 2008: 700,784,034

Documents Incorporated by Reference

List hereunder the following documents if incorporated by reference and the part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: Portions of our definitive proxy statement for the 2008 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2008.

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PART I

ITEM 1. BUSINESS

Business and Strategy

We are an energy company, originally founded in 1928 in El Paso, Texas that primarily operates in the natural gas transmission and exploration and production sectors of the energy industry. Our purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner.

Natural Gas Transmission. We own or have interests in North America's largest interstate pipeline system with approximately 42,000 miles of pipe that connect North America's major natural gas producing basins to its major consuming markets. We also provide approximately 230 Bcf of storage capacity and have an LNG receiving terminal and related facilities in Elba Island, Georgia with 806 MMcf of daily base load sendout capacity. The size, connectivity and diversity of our U.S. pipeline system provides growth opportunities through infrastructure development or large scale expansion projects and gives us the capability to adapt to the dynamics of shifting supply and demand. Our focus is to enhance the value of our transmission business by successfully executing on our backlog of committed expansion projects in the United States and Mexico and developing new growth projects in our market and supply areas.

Exploration and Production. Our exploration and production business is currently focused on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States, Brazil and Egypt. As of December 31, 2007, we held an estimated 2.9 Tcfe of proved natural gas and oil reserves, not including our equity share in the proved reserves of an unconsolidated affiliate of 0.2 Tcfe. In this business, we are focused on growing our reserve base through disciplined capital allocation and portfolio management, cost control and marketing our natural gas and oil production at optimal prices while managing associated price risks.

Our operations are conducted through two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. Our business segments provide a variety of energy products and services and are managed separately as each segment requires different technology and marketing strategies. For a further discussion of our business segments, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Pipelines Segment

Our Pipelines segment includes our interstate natural gas transmission systems and related operations conducted through four separate, wholly owned pipeline systems, three majority-owned systems and three partially owned systems. These systems connect the nation's principal natural gas supply regions to the five largest consuming regions in the United States: the Gulf Coast, California, the northeast, the southwest and the southeast. We also have access to systems in Canada and assets in Mexico. Our Pipelines segment also includes our ownership of storage capacity through our transmission systems, two underground storage facilities and our LNG terminal and related facilities.

Each of our U.S. pipeline systems and storage facilities operate under Federal Energy Regulatory Commission (FERC) approved tariffs that establish rates, cost recovery mechanisms, and other terms and conditions of service to our customers. The fees or rates established under our tariffs are a function of our costs of providing services to our customers, including a reasonable return on our invested capital.

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Our strategy is to enhance the value of our transmission and storage business by:

- Successfully executing on our backlog of committed expansion projects;
- Developing new growth projects in our market and supply areas;
- Recontracting or contracting available or expiring capacity;
- Focusing on efficiency and synergies across our systems;
- Ensuring the safety of our pipeline systems and assets; and
- Providing outstanding customer service.

In November 2007, we formed El Paso Pipeline Partners, L.P., our master limited partnership (MLP). We contributed our Wyoming Interstate system and 10 percent general partner interests in each of Southern Natural Gas and Colorado Interstate Gas to the MLP. Our ownership interest in the MLP at December 31, 2007 consists of a two percent general partner interest and a 64.8 percent limited partner interest.

The tables below provide more information on our pipeline systems:

Transmission System	Supply and Market Region	Ownership Percentage (Percent)	As of December 31, 2007 Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput (1) 2007	2006 (BBtu/d)	2005
Tennessee Gas Pipeline (TGP)	Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including the metropolitan areas of New York City and Boston.	100	13,700	7,069	92	4,880	4,534	4,443
El Paso Natural Gas (EPNG)	Extends from San Juan, Permian, Anadarko basins and via interconnects the Rocky Mountains to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	100	10,200	5,650 (2)	44	4,189	4,179	4,053
Mojave Pipeline (MPC)	Connects with the EPNG system near Cadiz, California, the EPNG and Transwestern systems at Topock, Arizona and to the Kern River Gas Transmission Company system in California. This system also extends to customers in the vicinity of Bakersfield, California.	100	400	400 (4)	—	458	461	161
Cheyenne Plains Gas Pipeline (CPG) (3)	Extends from Cheyenne hub and Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.	100	400	861	—	735	583	433

(1) Includes throughput transported on behalf of affiliates.

(2) Reflects winter-sustainable west-flow capacity of 4,850 MMcf/d and approximately 800 MMcf/d of east-end delivery capacity.

(3) Completed in 2005

(4) Reflects east to west flow capacity

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Transmission System	Supply and Market Region	As of December 31, 2007 Ownership Interest (Percent)	Miles of Pipeline (1)	Design Capacity (1) (MMcf/d)	Storage Capacity (1) (Bcf)	Average Throughput (1) 2007 (BBtu/d)	2006	2005
Southern Natural Gas (SNG)	Extends from natural gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham.	97	7,600	3,665	60	2,345	2,167	1,984
Colorado Interstate Gas (CIG)	Extends from production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and multiple interconnections with pipeline systems transporting gas to the midwest, the southwest, California and the Pacific northwest.	97	4,000	3,048	29	2,339	2,008	1,902
Wyoming Interstate (WIC) (2)	Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	67	800	2,721	—	2,071	1,914	1,572
Florida Gas Transmission (3) (FGT)	Extends from South Texas to South Florida.	50	4,881	2,100	—	2,056	2,018	1,916
Samalayuca Pipeline and Gloria a Dios Compression Station (4)	Extends from U.S.-Mexico border to the state of Chihuahua, Mexico.	50	23	460	—	462	442	423
San Fernando Pipeline (4)	Extends from Pemex Compression Station 19 to the Pemex metering station in San Fernando, Mexico in the State of Tamaulipas.	50	71	1,000	—	951	951	951

(1) Includes throughput transported on behalf of affiliates and represents the systems' totals and are not adjusted for our ownership interest.

(2) Includes the recently completed Kanda expansion project placed in service in January 2008.

(3) We have a 50 percent equity interest in Citrus Corp. (Citrus), which owns this system.

(4) We have a 50 percent equity interest in Gasoductos de Chihuahua, which owns these systems.

In December 2007, we placed the LPG Burgos pipeline in service. This 117 mile pipeline, in which we own 50%, transports liquified petroleum gas and extends from Pemex's Burgos complex to the Monterrey market in the state of Nuevo Leoń, Mexico. The system has a design capacity of 30 million barrels/day and in 2007 we transported an average of 30 million barrels/day.

As of December 31, 2007, we had the following FERC approved pipeline expansion projects on our systems. For a further discussion of other backlog expansion projects, see Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations.

Project	Existing System	Capacity (MMcf/d)	Description	Anticipated Completion or In-Service Date
Essex Middlesex Project	TGP	80	To construct 7.8 miles of 24-inch pipeline connecting our Beverly-Salem line to the DOMAC line in Essex and Middlesex Counties, Massachusetts	November 2008
Medicine Bow Expansion	WIC	330	To construct a new 24,930 horsepower compression facility which increases capacity from the Powder River Basin in northeast Wyoming to the WIC mainline near the Cheyenne Hub	July 2008
Cheyenne Plains Expansion	CPG	70	To construct a new compression facility comprised of 10,310 horsepower at the Kirk Compressor Station in Yuma County, Colorado	July 2008
Cypress Phase II	SNG	114	To add 10,350 horsepower of additional compression on pipeline facilities extending southward from our Elba Island facility	May 2008
Cypress Phase III	SNG	161	To add 20,700 horsepower of additional compression on pipeline facilities extending southward from our Elba Island facility	January 2011
Southeast Supply Header (Phase I)	SNG	140	To construct 115 miles of pipeline to the western portion of our system and provide access through pipeline interconnects to several supply basins	June 2008

Intrastate Transmission Systems

CIG has a 50 percent interest in WYCO Development, L.L.C. (WYCO). WYCO owns a state regulated intrastate gas pipeline that extends from the Cheyenne Hub in northeast Colorado to Public Service Company of Colorado's (PSCo) Fort St. Vrain electric generation plant. WYCO also owns a compressor station on our WIC system's Medicine Bow lateral in Wyoming and leases these pipeline and compression facilities to PSCo and WIC, respectively, under long-term leases. WYCO currently has two expansion projects underway, the High Plains pipeline and Totem storage expansion projects, expected to be completed in 2008 and 2009. CIG will lease these facilities and will be the operator of these projects.

Underground Natural Gas Storage Facilities

In addition to the storage along our pipeline systems, we own or have interests in the following natural gas storage facilities:

	As of December 31, 2007		
Storage Entity	Ownership Interest	Storage Capacity (1)	Location
	(Percent)	(Bcf)	
Bear Creek Storage	100	58	Louisiana
Young Gas Storage	48	6	Colorado

(1) Approximately 58 Bcf is contracted to affiliates. Amounts are not adjusted for our ownership interest.

LNG Facility

We own an LNG receiving terminal located on Elba Island, near Savannah, Georgia with a peak sendout capacity of 1.2 Bcf/d and a base load sendout capacity of 0.8 Bcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas Group and Royal Dutch Shell PLC.

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In September 2007, we received FERC approval to expand the Elba Island LNG receiving terminal and construct the Elba Express Pipeline. The expansion is anticipated to increase the peak sendout capacity of the terminal from 1.2 Bcf/d to 2.1 Bcf/d. The Elba Express Pipeline will consist of approximately 190 miles of pipeline with a total capacity of 1.2 Bcf/d, which will transport natural gas from the Elba Island LNG terminal to markets in the southeastern and eastern United States. In February 2008, we completed our acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, which is constructing a FERC approved liquefied natural gas terminal in Pascagoula, Mississippi that is expected to be placed in service in late 2011.

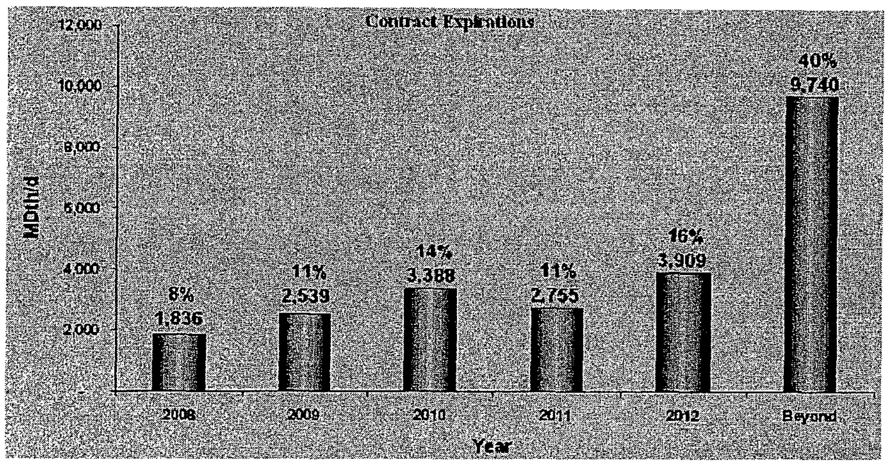
Markets and Competition

Our Pipelines segment provides natural gas services to a variety of customers, including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. In performing these services, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear energy, wind, hydroelectric power and fuel oil.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. LNG terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing their delivery capabilities and operational flexibility and complementing traditional supply transported into market areas. However, these LNG delivery systems may also compete with our pipelines for transportation of gas into the market areas we serve.

Electric power generation is the fastest growing demand sector of the natural gas market. The growth of the electric power industry potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power. This potential benefit is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity, increased natural gas prices and the use and availability of other fuel sources for power generation. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and electric transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm transportation contracts with natural gas pipelines.

Our existing contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our existing contracts or remarket expiring capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to recontract or remarket our capacity at the rates allowed under our tariffs although, at times, we discount these rates to remain competitive. The level of discount varies for each of our pipeline systems. The table below shows our firm transportation contracts as of December 31, 2007 for our wholly and majority owned systems that expire by year over the next five years and thereafter.



The following table details information related to our pipeline systems, including the customers, contracts, markets served and the competition faced by each as of December 31, 2007. Firm customers reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities and are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. Interruptible customers are customers without reserved capacity that pay usage charges based on the volume of gas they request to transport, store, inject or withdraw.

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TGP

Customer Information	Contract Information	Competition
Approximately 440 firm and interruptible customers.	Approximately 500 firm transportation contracts. Weighted average remaining contract term of approximately four years.	TGP faces competition in its northeast, Appalachian, midwest and southeast market areas. It competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on the TGP system competes with alternative energy sources such as electricity, hydroelectric power, coal and fuel oil. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and from the Canadian border.
Major Customer: National Grid USA and subsidiaries (722 BBtu/d)	Expire in 2009-2027.	
EPNG		
Approximately 140 firm and interruptible customers	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately four years.	EPNG faces competition in the west and southwest from other existing and proposed pipelines, from California storage facilities, and from alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil. In addition, construction of facilities to bring LNG into California and northern Mexico are underway.
Major Customers: Southern California Gas Company		
(187 BBtu/d)	Expires in 2009.	
(246 BBtu/d)	Expires in 2010.	
(323 BBtu/d)	Expires in 2011.	
Southwest Gas Corporation		
(11 BBtu/d)	Expires in 2008.	
(603 BBtu/d)	Expire in 2011-2015.	
MPC		
Approximately 20 firm and interruptible customers	Approximately five firm transportation contracts. Weighted average remaining contract term of approximately eight years.	MPC faces competition from other existing and proposed pipelines, and alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil. In addition, construction of facilities to bring LNG into California and northern Mexico are underway.
Major Customer: EPNG (312 BBtu/d)	Expires in 2015.	

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CPG

Customer Information	Contract Information	Competition
Approximately 50 firm and interruptible customers	Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately eight years.	CPG competes directly with other interstate pipelines serving the mid-continent region. Indirectly, CPG competes with pipelines that transport Rocky Mountain gas to other markets.
Major Customers:		
Oneok Energy Services Company L.P. (195 BBtu/d)	Expires in 2015.	
Encana Marketing (USA) Inc. (170 BBtu/d)	Expires in 2015.	
Anadarko Petroleum Corporation (195 BBtu/d)	Expire in 2015-2016.	
Coral Energy Resources, L.P. (125 BBtu/d)	Expires in 2019.	
SNG		
Approximately 280 firm and interruptible customers	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately six years.	SNG faces competition in a number of its key markets. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on SNG's system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil. SNG's four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, SNG competes with several pipelines for the transportation business of their other customers. In addition, SNG competes with pipelines and gathering systems for connection to new supply sources.
Major Customers:		
Atlanta Gas Light Company (981 BBtu/d)	Expire in 2008-2015.	
Southern Company Services (418 BBtu/d)	Expire in 2010-2018.	
Alabama Gas Corporation (413 BBtu/d)	Expire in 2010-2013.	
SCANA Corporation (315 BBtu/d)	Expire in 2010-2019.	

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CIG

Customer Information	Contract Information	Competition
Approximately 120 firm and interruptible customers	Approximately 180 firm transportation contracts. Weighted average remaining contract term of approximately five years.	CIG serves two major markets, an "on- system" market and an "off- system" market. Its 'on-system' market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Competitors in this market consist of an intrastate pipeline, an interstate pipeline, local production from the Denver-Julesburg basin, and long-haul shippers who elect to sell into this market rather than the off-system market. CIG's off-system market consists of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the midwest, the southwest, California and the Pacific northwest. Competition for this off-system market consists of interstate pipelines that are directly connected to its supply sources. CIG faces competition from other existing pipelines and alternative energy sources that are used to generate electricity such as hydroelectric power, wind, solar, coal and fuel oil.
Major Customers:		
PSCo		
(187 BBtu/d)	Expires in 2008.	
(9 BBtu/d)	Expires in 2009.	
(1,106 BBtu/d)	Expire in 2012-2014.	
Williams Gas Marketing, Inc.		
(53 BBtu/d)	Expires in 2009.	
(113 BBtu/d)	Expires in 2010.	
(350 BBtu/d)	Expire in 2011-2013.	
Anadarko Petroleum Corporation		
(70 BBtu/d)	Expires in 2008.	
(12 BBtu/d)	Expires in 2009.	
(80 BBtu/d)	Expires in 2010.	
(128 BBtu/d)	Expire in 2011-2015.	
WIC (1)		
Approximately 50 firm and interruptible customers	Approximately 50 firm transportation contracts. Weighted average remaining contract term of approximately ten years.	WIC competes with existing pipelines to provide transportation services from supply basins in northwest Colorado, eastern Utah and Wyoming to pipeline interconnects in northeast Colorado, and western Wyoming.
Major Customers:		
Williams Gas Marketing, Inc.		
(25 BBtu/d)	Expires in 2008.	
(84 BBtu/d)	Expires in 2010.	
(744 BBtu/d)	Expire in 2013-2021.	
Anadarko Petroleum Corporation		
(25 BBtu/d)	Expires in 2008.	
(810 BBtu/d)	Expire in 2009-2022.	

(1) Information included has been adjusted to reflect the completion of the Kanda expansion project placed in service in January 2008.

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Regulatory Environment. Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Each of our interstate pipeline systems and storage facilities operates under tariffs approved by the FERC that establish rates, cost recovery mechanisms, and terms and conditions for services to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage and related services;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipelines and certain affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

Our interstate pipeline systems are also subject to federal, state and local pipeline and LNG plant safety and environmental statutes and regulations of the U.S. Department of Transportation, the U.S. Department of Interior and the U.S. Coast Guard. We have ongoing inspection programs designed to keep our facilities in compliance with pipeline safety and environmental requirements, and we believe that our systems are in material compliance with the applicable regulations.

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Exploration and Production Segment

Our Exploration and Production segment's business strategy focuses on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States, Brazil and Egypt. As of December 31, 2007, we controlled over four million net leasehold acres and our proved natural gas and oil reserves at December 31, 2007, were approximately 2.9 Tcfe, which does not include 0.2 Tcfe related to our unconsolidated investment in Four Star Oil and Gas Company (Four Star). During 2007, daily equivalent natural gas production averaged approximately 792 MMcfe/d, not including 70 MMcfe/d from our equity investment in Four Star.

We completed the acquisition of Peoples Energy Production Company (Peoples) in September 2007 for $887 million. This acquisition upgraded our portfolio of assets across a number of our operating regions, primarily the Onshore and Texas Gulf Coast regions. We are also further upgrading our portfolio by selling selected non-core properties that no longer meet our strategic objectives. In January 2008, we entered into agreements to sell $517 million of certain non-core properties in our Onshore and Texas Gulf Coast regions with estimated proved reserves of 191 Bcfe at December 31, 2007. While we do not anticipate exiting any region, our divestitures will be weighted towards the Gulf of Mexico and south Texas areas. We have a balanced portfolio of development and exploration projects, including long-lived and shorter-lived properties divided into the following regions discussed below:

United States

Onshore. The Onshore region includes operations that are primarily focused on unconventional tight gas sands, coal bed methane and lower risk conventional producing areas, which are generally characterized by lower development costs, higher drilling success rates and longer reserve lives. We have a large inventory of drilling prospects in this region. During 2007, we invested $543 million on capital projects, not including acquisitions, and production averaged 374 MMcfe/d. The principal operating areas are listed below:

		2007		
Area	**Description**	**Net Acres**	**Capital Investment**	**Average Production (MMcfe/d)**
			(In millions)	
East Texas/North Louisiana (Arklatex)	Concentrated land positions primarily focused on tight gas sands production in the Travis Peak/Hosston, Bossier and Cotton Valley formations. The Peoples acquisition added to our existing asset in this area most notably in Logansport, Bald Prairie, Bethany, Minden and Bethany Longstreet fields. We also have land positions in the Mississippi area, primarily in Hub Field located on the southern edge of the Mississippi Salt Basin.	113,000	$260	136
Black Warrior Basin	Established shallow coal bed methane producing areas of northwestern Alabama. We have high average working interests in our operated properties in addition to an average 50 percent working interest covering approximately 46,000 net acres operated by Black Warrior Methane which produces from the Brookwood Field.	171,000	$ 51	62
Mid-Continent	Primarily in Oklahoma with a focus on development projects in the Arkoma Basin where we utilize horizontal drilling in the Hartshorne Coals area; West Verdon Field, an oil producing waterflood project and shallow natural gas production in the Hugoton field.	456,000	$ 40	30
Rocky Mountains (Rockies)	Primarily in Wyoming and Utah with a focus in the Powder River and Uinta basins, consisting predominantly of operated oil fields utilizing both primary and secondary recovery methods combined with non-operated coal bed methane fields. We operate the Altamont and Bluebell processing plants and related gathering systems in Utah. We also have a non-operated working interest primarily in the Stadium Unit in the Williston Basin of North Dakota, which is undergoing secondary recovery.	357,000	$ 79	71

Area	Description	2007 Net Acres	2007 Capital Investment (In millions)	2007 Average Production (MMcfe/d)
Raton Basin	Primarily focused on coal bed methane production in northern New Mexico and southern Colorado where we own the minerals and have a 100 percent working interest in the Vermejo Park Ranch. We also have working interests in land positions in the San Juan Basin primarily in the Fruitland Coal and Dakota formations and the tight gas formations in Pictured Cliffs and Mesaverde.	605,000	$113	75

Included in our Mid-Continent operating area are our interests in 127,000 net acres in West Virginia and 122,000 net acres in the Illinois Basin, primarily in the New Albany Shale area in southwestern Indiana. We are the operator of these properties and maintain a 50 percent working interest in this large emerging area which is still under evaluation. We have drilled 34 gross wells in this basin through the end of 2007.

Texas Gulf Coast. The Texas Gulf Coast region focuses on developing and exploring for tight gas sands in south Texas and the upper Gulf Coast of Texas. In this area, we have an inventory of over 10,000 square miles of three dimensional (3D) seismic data. During 2007, we acquired producing properties and undeveloped acreage in Zapata County, Texas for $254 million. During 2007, we also invested $327 million on capital projects and production averaged 213 MMcfe/d. The principal operating areas are listed below:

Area	Description	2007 Net Acres	2007 Capital Investment (In millions)	2007 Average Production (MMcfe/d)
Vicksburg/Frio Trends	Includes concentrated and contiguous assets, located in south Texas, including the Jeffress and Monte Christo fields primarily in Hidalgo County, in which we have an average 90 percent working interest. We also have assets in the Alvarado and Kelsey fields and in Starr and Brooks Counties with an average working interest of over 65 percent.	83,000	$128	132
Upper Gulf Coast Wilcox	Located onshore Texas Gulf Coast, including Renger, Dry Hollow, Brushy Creek and Speaks fields in Lavaca County and Graceland Field, located in Colorado, County.	37,000	$ 56	32
South Texas Wilcox	Includes positions in which we have working interests in Bob West, Jennings Ranch and Roleta fields in Zapata County. We also have working interests in the Laredo and Loma Novia fields in Webb and Duval counties.	79,000	$143	49

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Gulf of Mexico and south Louisiana. Our Gulf of Mexico and south Louisiana operations are generally characterized by relatively high initial production rates, resulting in near-term cash flows, and high decline rates. During 2007, we invested $309 million on drilling, workover and facilities projects and production averaged 191 MMcfe/d. The principal operating areas are listed below:

		2007		
Area	Description	Net Acres	Capital Investment (In millions)	Average Production (MMcfe/d)
Gulf of Mexico	Primarily drilling interests in 148 Blocks south of the Louisiana, Texas and Alabama shorelines focused on deep (greater than 12,000 feet) natural gas and oil reserves in relatively shallow water depths (less than 300 feet).	543,000	$281	174
South Louisiana	Primarily in Vermilion Parish and associated bays and inland waters in southwestern Louisiana covered by the Catapult 3D seismic project. We have internally processed 2,800 square miles of contiguous 3D seismic data in this project.	21,000	$ 28	17

Unconsolidated Investment in Four Star. During the third quarter of 2007, we increased our ownership interest in Four Star from 43 percent to 49 percent. Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama Basins and the Gulf of Mexico. During 2007, our proportionate share of Four Star's daily equivalent natural gas production averaged approximately 70 MMcfe/d and at December 31, 2007, proved natural gas and oil reserves, net to our interest, were 0.2 Tcfe.

International

Brazil. Our Brazilian operations cover approximately 361,000 net acres. During 2007, we invested $220 million on capital projects in Brazil. Our operations include interests in 13 concessions located in the Espirito Santo, Potiguar and Camamu Basins, including our 35 percent working interest in the Pescada-Arabaiana Fields in the Potiguar Basin. We currently own 100 percent of the BM-CAL-4 concession which includes the Pinauna project. During 2007, we completed drilling two successful exploratory wells that extended the southern limits of the Pinauna project. We are currently assessing development options and have a process underway to potentially market up to a 50 percent non-operating interest in this concession. In addition, we completed drilling and testing two exploratory wells with Petrobras in the ES-5 Block in the Espirito Basin. These wells confirmed the extension of an earlier discovery by Petrobras on a block to the south. Our production in Brazil, primarily attributable to the Pescada-Arabaiana Fields, averaged approximately 14 MMcfe/d in 2007.

Egypt. Our Egyptian operations include a 20 percent non-operated working interest in approximately 13,000 net acres in the South Feiran concession located in the Gulf of Suez. We are currently in the seismic, exploratory drilling and evaluation phases of the project. Our total funding commitment to the South Feiran concession is $3 million. In 2007, we received formal government approval and signed the concession agreement for the South Mariut Block. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta. We paid $3 million for the concession and agreed to a $22 million firm working commitment over three years. We are currently performing seismic evaluations on the block and expect to drill our first exploratory well in late 2008.

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Natural Gas and Oil Properties

Natural Gas, Oil and Condensate and NGL Reserves and Production

The table below presents our estimated proved reserves by region and classification as of December 31, 2007 based on an internal reserve report as well as our 2007 production by region. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

	Net Proved Reserves					2007
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe)	Total (Percent)	Production (MMcfe)
Reserves and Production by Region						
United States						
Onshore	1,567,666	36,308	301	1,787,318	63%	136,701
Texas Gulf Coast	471,448	3,806	9,205	549,513	19%	77,633
Gulf of Mexico and south Louisiana	207,546	9,560	608	268,555	9%	69,671
Total United States	2,246,660	49,674	10,114	2,605,386	91%	284,005
Brazil	51,206	32,710	—	247,468	9%	5,237
Total	2,297,866	82,384	10,114	2,852,854	100%	289,242
Unconsolidated investment in Four Star	200,109	2,858	6,411	255,722	100%	25,470
Reserves by Classification						
United States						
Producing	1,419,621	26,578	6,679	1,619,159	62%	
Non-Producing	318,475	8,492	1,453	378,147	15%	
Undeveloped	508,564	14,604	1,982	608,080	23%	
Total proved	2,246,660	49,674	10,114	2,605,386	100%	
Brazil						
Producing	15,229	342	—	17,281	7%	
Non-Producing	3,414	338	—	5,444	2%	
Undeveloped	32,563	32,030	—	224,743	91%	
Total proved	51,206	32,710	—	247,468	100%	
Worldwide						
Producing	1,434,850	26,920	6,679	1,636,440	58%	
Non-Producing	321,889	8,830	1,453	383,591	13%	
Undeveloped	541,127	46,634	1,982	832,823	29%	
Total proved	2,297,866	82,384	10,114	2,852,854	100%	
Unconsolidated investment in Four Star						
Producing	167,114	2,804	5,316	215,828	85%	
Non-Producing	3,072	—	29	3,246	1%	
Undeveloped	29,923	54	1,066	36,648	14%	
Total Four Star	200,109	2,858	6,411	255,722	100%	

Our consolidated reserves in the table above are consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

Ryder Scott Company, L.P. (Ryder Scott), an independent reservoir engineering firm that reports to the Audit Committee of our Board of Directors, conducted an audit of the estimates of 84 percent of our consolidated proved natural gas and oil reserves as of December 31, 2007. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising greater than 80 percent of our total worldwide present value of future cash flows (pretax). The specific fields included in Ryder Scott's audit represented the largest fields based on value. Ryder Scott also conducted an audit of the estimates of 75 percent of the proved natural gas and oil reserves of Four Star, our unconsolidated affiliate. Our estimates of Four Star's proved natural gas and oil reserves are prepared by our internal reservoir engineers and do not reflect

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those prepared by the engineers of Four Star. Based on the amount of proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable. Ryder Scott's reports are included as exhibits to this Annual Report on Form 10-K.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production costs, and projecting the timing of development expenditures, including many factors beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The reserve data represents only estimates which are often different from the quantities of natural gas and oil that are ultimately recovered. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based, and on engineering and geological interpretations and judgment.

All estimates of proved reserves are determined according to the rules currently prescribed by the Securities and Exchange Commission (SEC). These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive or upward revision is more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate.

In general, the volume of production from natural gas and oil properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with proved reserves, or both, our proved reserves will decline as reserves are produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of proved undeveloped reserves and proved non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2007, (ii) our interest in natural gas and oil wells at December 31, 2007 and (iii) our exploratory and development wells drilled during the years 2005 through 2007. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Acreage						
United States						
Onshore	1,026,566	627,034	1,524,237	1,075,443	2,550,803	1,702,477
Texas Gulf Coast	173,282	119,025	114,842	80,396	288,124	199,421
Gulf of Mexico and south Louisiana	517,597	376,378	220,314	187,506	737,911	563,884
Total United States	1,717,445	1,122,437	1,859,393	1,343,345	3,576,838	2,465,782
Brazil	49,262	17,242	1,158,643	343,563	1,207,905	360,805
Egypt	—	—	1,247,064	1,195,272	1,247,064	1,195,272
Worldwide Total	1,766,707	1,139,679	4,265,100	2,882,180	6,031,807	4,021,859

(1) Gross interest reflects the total acreage we participated in, regardless of our ownership interest in the acreage.

(2) Net interest is the aggregate of the fractional working interests that we have in the gross acreage.

In the United States, our net developed acreage is concentrated primarily in the Gulf of Mexico (33 percent), Texas (13 percent), Utah (11 percent), New Mexico (10 percent), Alabama (8 percent), Oklahoma (8 percent) and Louisiana (7 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (34 percent), the Gulf of Mexico (14 percent), Wyoming (10 percent), West Virginia (10 percent), Indiana (8 percent), Alabama (6 percent) and Texas (6 percent). Approximately 14 percent, 8 percent and 5 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2008, 2009 and 2010. Approximately 17 percent, 14 percent and 17 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2008, 2009 and 2010. Approximately 30 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2010. We employ various techniques to manage the expiration of leases, including extending lease terms, drilling the acreage ourselves, or through farm-out agreements with other operators.

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	Natural Gas		Oil		Total		Wells Being Drilled at December 31, 2007	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)(3)	Gross (1)	Net (2)
Productive Wells								
United States								
Onshore	4,901	3,627	658	495	5,559	4,122	74	61
Texas Gulf Coast	1,643	1,167	—	—	1,643	1,167	8	7
Gulf of Mexico and south Louisiana	193	127	56	31	249	158	2	1
Total	6,737	4,921	714	526	7,451	5,447	84	69
Brazil	4	1	6	2	10	3	—	—
Worldwide Total	6,741	4,922	720	528	7,461	5,450	84	69

	Net Exploratory (2)(4)			Net Development (2)(4)		
	2007	2006	2005	2007	2006	2005
Wells Drilled						
United States						
Productive	214	106	86	238	319	279
Dry	12	6	2	1	2	4
Total	226	112	88	239	321	283
Brazil						
Productive	3	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	3	—	—	—	—	—
Worldwide						
Productive	217	106	86	238	319	279
Dry	12	6	2	1	2	4
Total	229	112	88	239	321	283

(1) Gross interest reflects the total wells we participated in, regardless of our ownership interest.

(2) Net interest is the aggregate of the fractional working interests that we have in the gross wells or gross wells drilled.

(3) At December 31, 2007, we operated 4,905 of the 5,450 net productive wells.

(4) In 2007, there was a reduction in the number of non-operated development wells drilled in the Rockies and an increase in the number of exploration wells drilled in the Raton Basin.

The drilling performance above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

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Net Production, Sales Prices, Transportation and Production Costs

The following table details our net production volumes, average sales prices received, average transportation costs and average production costs (including production taxes) associated with the sale of natural gas and oil for each of the three years ended December 31:

	2007	2006	2005
Consolidated Volumes, Prices, and Costs per Unit			
Net Production Volumes			
United States			
Natural gas (MMcf)	238,021	213,262	206,714
Oil, condensate and NGL (MBbls)	7,664	7,439	7,516
Total (MMcfe)	284,005	257,899	251,807
Brazil (1)			
Natural gas (MMcf)	4,295	7,140	15,578
Oil, condensate and NGL (MBbls)	157	247	620
Total (MMcfe)	5,237	8,619	19,300
Worldwide			
Natural gas (MMcf)	242,316	220,402	222,292
Oil, condensate and NGL (MBbls)	7,821	7,686	8,136
Total (MMcfe)	289,242	266,518	271,107
Total (MMcfe/d)	792	730	743
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Excluding hedges	$ 6.60	$ 6.77	$ 7.92
Including hedges	$ 7.36	$ 6.50	$ 6.69
Brazil			
Excluding hedges	$ 2.61	$ 2.61	$ 2.33
Including hedges	$ 2.61	$ 2.61	$ 2.33
Worldwide			
Excluding hedges	$ 6.53	$ 6.64	$ 7.53
Including hedges	$ 7.28	$ 6.38	$ 6.39
Oil, Condensate and NGL Average Realized Sales Price ($/Bbl)			
United States			
Excluding hedges	$ 63.56	$ 55.95	$ 45.86
Including hedges	$ 63.56	$ 55.95	$ 45.86
Brazil			
Excluding hedges	$ 70.86	$ 64.02	$ 53.42
Including hedges	$ 41.27	$ 54.48	$ 42.42
Worldwide			
Excluding hedges	$ 63.71	$ 56.21	$ 46.43
Including hedges	$ 63.11	$ 55.90	$ 45.60
Average Transportation Costs			
United States			
Natural gas ($/Mcf)	$ 0.27	$ 0.24	$ 0.20
Oil, condensate and NGL ($/Bbl)	$ 0.83	$ 0.85	$ 0.69
Worldwide			
Natural gas ($/Mcf)	$ 0.27	$ 0.23	$ 0.18
Oil, condensate and NGL ($/Bbl)	$ 0.81	$ 0.82	$ 0.63

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	2007	2006	2005
Average Production Costs ($/Mcfe)			
United States			
Lease operating costs	$ 0.86	$ 0.97	$ 0.73
Production taxes	0.31	0.28	0.27
Total production costs	$ 1.17	$ 1.25	$ 1.00
Brazil			
Lease operating costs	$ 1.63	$ 0.28	$ 0.42
Production taxes	0.51	0.53	—
Total production costs	$ 2.14	$ 0.81	$ 0.42
Worldwide			
Lease operating costs	$ 0.88	$ 0.95	$ 0.72
Production taxes	0.31	0.29	0.24
Total production costs	$ 1.19	$ 1.24	$ 0.96
Unconsolidated affiliate volumes (Four Star) (2)			
Natural gas (MMcf)	19,380	18,140	6,689
Oil, condensate and NGL (MBbls)	1,015	1,087	359
Total equivalent volumes			
MMcfe	25,470	24,663	8,844
MMcfe/d	70	68	24

(1) Production volumes in Brazil decreased due to a contractual reduction of our ownership interest in the Pescada-Arabaiana Fields in early 2006.

(2) Includes our proportionate share of volumes in Four Star which was acquired in 2005. In the third quarter of 2007, we increased our ownership interest in Four Star from 43 percent to 49 percent.

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Acquisition, Development and Exploration Expenditures

The following table details information regarding the costs incurred in our acquisition, development and exploration activities for each of the three years ended December 31:

	2007	2006	2005
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 964	$ 2	$ 643
Unproved	262	34	143
Development Costs	735	738	503
Exploration Costs:			
Delay rentals	6	6	3
Seismic acquisition and reprocessing	19	23	7
Drilling	373	294	133
Asset Retirement Obligations	38	3	1
Total full cost pool expenditures	2,397	1,100	1,433
Non-full cost pool expenditures	13	8	22
Total costs incurred (1)	$ 2,410	$ 1,108	$ 1,455
Acquisition of unconsolidated investment in Four Star (2)	$ 27	$ —	$ 769
Brazil and Other International (1)			
Acquisition Costs:			
Proved	$ —	$ 2	$ 8
Unproved	5	1	1
Development Costs	26	40	6
Exploration Costs:			
Seismic acquisition and reprocessing	6	7	7
Drilling	193	46	8
Asset Retirement Obligations	7	—	—
Total full cost pool expenditures	237	96	30
Non-full cost pool expenditures	1	—	—
Total costs incurred	$ 238	$ 96	$ 30
Worldwide			
Acquisition Costs:			
Proved	$ 964	$ 4	$ 651
Unproved	267	35	144
Development Costs	761	778	509
Exploration Costs:			
Delay rentals	6	6	3
Seismic acquisition and reprocessing	25	30	14
Drilling	566	340	141
Asset Retirement Obligations	45	3	1
Total full cost pool expenditures	2,634	1,196	1,463
Non-full cost pool expenditures	14	8	22
Total costs incurred (1)	$ 2,648	$ 1,204	$ 1,485
Acquisition of unconsolidated investment in Four Star (2)	$ 27	$ —	$ 769

(1) Costs incurred for Egypt were $10 million and $4 million for the years ended December 31, 2007 and 2006.

(2) In 2005, amount includes deferred tax adjustments of $179 million related to the acquisition of full-cost pool properties and $217 million related to the acquisition of our unconsolidated investment in Four Star.

We spent approximately $200 million in 2007, $192 million in 2006 and $247 million in 2005 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

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Markets and Competition

We primarily sell our domestic natural gas and oil to third parties through our Marketing segment at spot market prices, subject to customary adjustments. We sell our NGL at market prices under monthly or long-term contracts, subject to customary adjustments. In Brazil, we sell the majority of our natural gas and oil to Petrobras, Brazil's state-owned energy company. We also enter into derivative contracts on our natural gas and oil production to stabilize our cash flows, reduce the risk and financial impact of downward commodity price movements and to protect the economic assumptions associated with our capital investment programs. As of December 31, 2007, our Exploration and Production segment had entered into derivative swap and option contracts on approximately 141 TBtu of our anticipated 2008 natural gas production, 16 TBtu of our total anticipated 2009-2012 natural gas production, basis swaps on 97 TBtu of our anticipated 2008 production and 15 TBtu of our total anticipated 2009-2012 natural gas production and fixed price swaps on 2,498 MBbls of our anticipated 2008 oil production. For a further discussion of these contracts, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. Our Marketing segment has also entered into additional production related derivative contracts as further described below.

The exploration and production business is highly competitive in the search for and acquisition of additional natural gas and oil reserves and in the sale of natural gas, oil and NGL. Our competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price and contract terms, our ability to access drilling and other equipment and our ability to hire and retain skilled personnel on a timely and cost effective basis. Ultimately, our future success in the exploration and production business will be dependent on our ability to find or acquire additional reserves at costs that yield acceptable returns on the capital invested.

Regulatory Environment. Our natural gas and oil exploration and production activities are regulated at the federal, state and local levels, in the United States, Brazil and Egypt. These regulations include, but are not limited to, those governing the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to governmental safety regulations in the jurisdictions in which we operate.

Our domestic operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. Our exploration and production operations in Brazil and Egypt are subject to environmental regulations administered by those governments, which include political subdivisions in those countries. These domestic and international laws and regulations affect the construction and operation of facilities, water disposal rights, drilling operations, production or the delay or prevention of future offshore lease sales. In addition, we maintain insurance to limit exposure to sudden and accidental pollution liability exposures.

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Marketing Segment

Our Marketing segment's primary focus is to market our Exploration and Production segment's natural gas and oil production and to manage the Company's overall price risk, primarily through the use of natural gas and oil derivative contracts. In addition, we continue to manage and liquidate various natural gas supply, transportation, power and other natural gas related contracts remaining from our legacy trading activities, which were primarily entered into prior to the deterioration of the energy trading environment in 2002. As of December 31, 2007, we managed the following types of contracts:

- *Production-Related Natural Gas and Oil Derivative Contracts.* Includes options that provide price protection on our Exploration and Production segment's natural gas and oil production.
- *Natural Gas Transportation-Related Contracts.* Includes contracts that provide transportation capacity primarily with our affiliates.
- *Legacy Natural Gas and Power Contracts.* Includes a variety of natural gas derivative contracts and long-term supply obligations, including our Midland Cogeneration Venture (MCV) supply agreement and power contracts in the Pennsylvania-New Jersey-Maryland (PJM) region.

Production-Related Natural Gas and Oil Derivative Contracts

Our natural gas and oil contracts include options designed to provide price protection to El Paso from fluctuations in natural gas and oil prices. These contracts are in addition to contracts entered into by our Exploration and Production segment described in that segment. For a further discussion of the entirety of El Paso's production-related price risk management activities, refer to Item 7, Management's Discussion and Analysis of Financial Condition, Results of Operations and Liquidity and Capital Resources. As of December 31, 2007, our Marketing segment's contracts provided El Paso with price protection on the following quantities of future natural gas and oil production:

	2008	2009
Natural Gas (TBtu)		
Volumes with floor and ceiling prices	—	17
Oil (MBbls)		
Volumes with floor and ceiling prices	930	—

Contracts Related to Legacy Trading Operations

Natural gas transportation-related contracts. Our transportation contracts give us the right to transport natural gas using pipeline capacity for a fixed reservation charge plus variable transportation costs. Our ability to utilize our transportation capacity under these contracts is dependent on several factors, including the difference in natural gas prices at receipt and delivery locations along the pipeline system, the amount of working capital needed to use this capacity and the capacity required to meet our other long-term obligations. The following table details our transportation contracts as of December 31, 2007:

	Affiliated Pipelines [1]	Other Pipelines
Daily capacity (MMBtu/d)	521,000	63,000
Expiration	2009 to 2028	2012 to 2026
Receipt points	Various	Various
Delivery points	Various	Various

(1) Primarily consists of contracts with TGP and EPNG.

Other natural gas contracts. As of December 31, 2007, we had eight significant physical natural gas contracts with power plants associated with our legacy trading activities, including MCV. We sold our equity investment in the MCV power facility in 2006. These contracts obligate us to sell gas to these plants and have various expiration dates ranging from 2008 to 2028, with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 130,000 MMBtu/d.

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Power contracts. As of December 31, 2007, we had four derivative contracts that require us to swap locational differences in power prices between four power plants in the PJM eastern region with the PJM west hub. In total, these contracts require us annually to swap locational differences in power prices on approximately 4,000 GWh of power through 2008; 3,700 GWh from 2009 to 2012; 2,400 GWh for 2013 and 1,700 GWh from 2014 to 2016. Additionally, these contracts require us to provide installed capacity of approximately 71 GWh per year in the PJM power pool through 2016. While we have basis and capacity risk associated with the contracts, we do not have commodity risk associated with these contracts due to positions we put in place prior to 2007.

Markets, Competition and Regulatory Environment

Our Marketing segment operates in a highly competitive environment, competing on the basis of price, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served is influenced directly or indirectly by energy market economics. Our primary competitors include major oil and natural gas producers and their affiliates, large domestic and foreign utility companies, large local distribution companies and their affiliates, other interstate and intrastate pipelines and their affiliates, and independent energy marketers and financial institutions. Our marketing activities are subject to the regulations of among others, the FERC and the Commodity Futures Trading Commission.

Power Segment

As of December 31, 2007, our Power segment primarily included the ownership and operation of our remaining investments in international power generation facilities listed below. These facilities primarily sell power under long-term power purchase agreements with power transmission and distribution companies owned by local governments. As a result, we are subject to certain political risks related to these facilities. We continue to pursue the sale of our remaining power investments.

Project	Area	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Brazil						
Manaus (1)	Brazil	100	238	Manaus Energia	2008	Oil
Porto Velho (2)	Brazil	50	404	Eletronorte	2010, 2023	Oil
Rio Negro (1)	Brazil	100	158	Manaus Energia	2008	Oil
Asia & Central America						
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
Khulna Power Co.	Bangladesh	74	113	BPDB	2013	Heavy Fuel Oil
Tipitapa (3)	Nicaragua	60	51	Union Fenosa	2014	Heavy Fuel Oil

(1) Ownership of these plants transferred to the power purchaser in January 2008.

(2) In the third quarter of 2007, we received an offer from our partners to purchase this investment. For further discussion, see Item 8, Financial Statements, Note 17.

(3) In December 2007, we signed an agreement to sell this facility which is expected to close in the first half of 2008.

In addition to the international power plants above, we also have investments in two operating pipelines in South America with a total design capacity and average 2007 throughput of 1,197 MMcf/d and 1,162 BBtu/d, unadjusted for our ownership interest.

Regulatory Environment. Our remaining international power generation activities are regulated by governmental agencies in the countries in which these projects are located. Many of these countries have developed or are developing new regulatory and legal structures for private and foreign-owned businesses. These regulatory and legal structures are subject to change over time.

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Employee Stock Purchase Plan. Our employee stock purchase plan allows participating employees the right to purchase our common stock at 95 percent of the market price on the last trading day of each month. This plan is non-compensatory under the provisions of SFAS No. 123 (R). Shares issued under this plan were insignificant during 2007, 2006 and 2005.

16. Business Segment Information

As of December 31, 2007, our business consists of two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. Prior to 2006, we also had a Field Services segment. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as other miscellaneous businesses and various other contracts and assets, all of which are immaterial. A further discussion of each segment follows.

Pipelines. Provides natural gas transmission, storage, and related services, primarily in the United States. As of December 31, 2007, we conducted our activities primarily through seven wholly or majority owned interstate pipeline systems and equity interests in three interstate transmission systems, along with two underground natural gas storage entities and an LNG terminalling facility.

Exploration and Production. Engaged in the exploration for and the acquisition, development and production of natural gas, oil and NGL, primarily in the United States, Brazil and Egypt.

Marketing. Markets and manages the price risks associated with our natural gas and oil production as well as our remaining legacy trading portfolio.

Power. Manages the risks associated with our remaining international power assets, primarily in Brazil, Asia and Central America. We continue to pursue the sale of these assets.

Prior to January 1, 2006, we had a Field Services segment which conducted midstream activities. We have disposed of substantially all of the assets in this segment.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2007, 2006 and 2005.

Our management uses earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income or loss adjusted for (i) items that do not impact our income or loss from continuing operations, such as discontinued operations and the impact of accounting changes, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income from continuing operations for the periods ended December 31:

	2007	2006 (In millions)	2005
Segment EBIT	$ 1,935	$ 1,838	$ 979
Corporate and other	(283)	(88)	(521)
Interest and debt expense	(994)	(1,228)	(1,295)
Income taxes	(222)	9	331
Income (loss) from continuing operations	$ 436	$ 531	$ (506)

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The following tables reflect our segment results as of and for each of the three years ended December 31:

	As of or for the Year Ended December 31, 2007					
	Segment					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other [1]	Total
			(In millions)			
Revenue from external customers						
Domestic	$ 2,429	$1,123[2]	$ 814	$ —	$ 54	$ 4,420
Foreign	11	17[2]	163	—	37	228
Intersegment revenue	54	1,160[2]	(1,196)	—	(18)	—
Operation and maintenance	753	439	11	17	113	1,333
Depreciation, depletion and amortization	373	780	3	1	19	1,176
Earnings (losses) from unconsolidated affiliates	105	11	—	(15)	—	101
EBIT	1,265	909	(202)	(37)	(283) [5]	1,652
Discontinued operations, net of income taxes	674	—	—	—	—	674
Assets of continuing operations						
Domestic	13,764	7,404	506	5	1,482	23,161
Foreign [3]	175	625	31	526	61	1,418
Capital expenditures and investments in and advances to unconsolidated affiliates, net [4]	1,059	2,613	—	(34)	7	3,645
Total investments in unconsolidated affiliates	759	704	—	151	—	1,614

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $19 million and an operation and maintenance expense elimination of $1 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Of total foreign assets, approximately $0.6 billion relates to property, plant and equipment, and approximately $0.6 billion relates to investments in and advances to unconsolidated affiliates.

(4) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

(5) Includes debt extinguishment costs of $86 million related to refinancing EPEP's $1.2 billion notes.

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	As of or for the Year Ended December 31, 2006					
	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate [1] and Other	Total
			(In millions)			
Revenue from external customers						
Domestic	$ 2,331	$ 645[2]	$ 1,012	$ 4	$ 116	$ 4,108
Foreign	10	32[2]	131	—		173
Intersegment revenue	61	1,177[2]	(1,201)	2	(39)	—
Operation and maintenance	743	410	28	57	99	1,337
Depreciation, depletion and amortization	370	645	4	2	26	1,047
Earnings from unconsolidated affiliates	90	10	—	45	—	145
EBIT	1,187	640	(71)	82	(88)	1,750
Discontinued operations, net of *income taxes*	118	—	—	(27)	(147)	(56)
Assets of continuing operations [3]						
Domestic	12,958	5,858	1,115	—	1,950	21,881
Foreign [4]	147	404	28	618	50	1,247
Capital expenditures, and investments in and advances to unconsolidated affiliates, net [5]	1,023	1,113	—	(44)	14	2,106
Total investments in unconsolidated affiliates	757	729	—	221	—	1,707

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $37 million and an operation and maintenance expense elimination of $13 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Excludes assets of discontinued operations of $4,133 million (see Note 2).

(4) Approximately $0.4 billion of total foreign assets relates to property, plant and equipment and approximately $0.7 billion relates to investments in and advances to unconsolidated affiliates.

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

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	As of or for the Year Ended December 31, 2005						
	Segments						
	Pipelines	Exploration and Production	Marketing	Power	Field Services	Corporate [1] and Other	Total
	(In millions)						
Revenue from external customers							
Domestic	$ 2,094	$ 466[2]	$ 411	$ 71	$ 96	$ 85	$ 3,223
Foreign	7	54[2]	3	—	—	—	64
Intersegment revenue	70	1,267[2]	(1,210)	11	27	(93)	72[3]
Operation and maintenance	772	383	54	122	37	567	1,935
Depreciation, depletion and amortization	343	612	4	2	3	42	1,006
Earnings (losses) from unconsolidated affiliates	100	19	—	(139)	301	—	281
EBIT	924	696	(837)	(89)	285	(521)	458
Discontinued operations, net of income taxes	154	9	—	(476)	251	(34)	(96)
Assets of continuing operations [4]							
Domestic	12,264	5,215	3,786	70	99	4,081	25,515
Foreign [5]	125	355	33	1,106	—	57	1,676
Capital expenditures, and investments in and advances to unconsolidated affiliates, net [6]	780	1,851	—	5	8	14	2,658
Total investments in unconsolidated affiliates	734	761	—	670	—	—	2,165

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $91 million and an operation and maintenance expense elimination of $2 million, which is included in the "Corporate" column, to remove *intersegment transactions.*

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $4,649 million.

(5) Of total foreign assets, approximately $0.3 billion relates to property, plant and equipment and approximately $1.0 billion relates to investments in and advances to unconsolidated affiliates.

(6) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

Enbridge Energy Partners, L.P.
2007 Form 10-K

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended DECEMBER 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.
(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**39-1715850** (I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, Texas 77002
(Address of principal executive offices and zip code)

(713) 821-2000
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Registrant's Class A Common Units held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2007, was $3,067,260,854.

As of February 20, 2008 the Registrant has 55,238,834 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

PART I

Item 1.—Business

OVERVIEW

In this report, unless the context requires otherwise, references to "we," "us," "our," or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We are a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transportation and marketing assets in the United States of America. Our Class A common units are traded on the NYSE under the symbol "EEP."

We were formed in 1991 by our general partner to own and operate the Lakehead system, which is the U.S. portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada. A subsidiary of Enbridge owns the Canadian portion of the System. Enbridge, which is based in Calgary, Alberta, provides energy transportation, distribution and related services in North America and internationally. Enbridge is the ultimate parent of our general partner.

We are a geographically and operationally diversified partnership consisting of interests and assets relating to the midstream energy sector. As of December 31, 2007, our portfolio of assets include the following:

- Approximately 5,000 miles of crude oil gathering and transportation lines and 28.9 million barrels, or Bbl, of crude oil storage and terminaling capacity.
- Natural gas gathering and transportation lines totaling approximately 11,500 miles.
- Ten active natural gas treating and 24 active natural gas processing facilities with an aggregate capacity of approximately 2,800 million cubic feet per day, or MMcf/d.
- Trucks, trailers and railcars for transporting natural gas liquids, or NGLs, crude oil and carbon dioxide.
- Marketing assets that provide natural gas supply, transmission, storage and sales services.

Enbridge Management is a Delaware limited liability company that was formed in May 2002 to manage our business and affairs. Under a delegation of control agreement, our general partner delegated substantially all of its power and authority to manage our business and affairs to Enbridge Management. Our general partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management is the sole owner of a special class of our limited partner interests, which we refer to as "i-units."

Our ownership at December 31, 2007 is comprised of the following:

	2007
Class A common units owned by the public	59.6%
Class B common units owned by our general partner	4.2%
Class C units owned by our general partner	6.4%
Class C units owned by institutional investors	13.1%
i-units owned by Enbridge Management	14.7%
General Partner interest	2.0%
	100.0%

BUSINESS STRATEGY

Our primary objective is to provide stable and sustainable cash distributions to our unitholders, while maintaining a relatively low investment risk profile. Our business strategies focus on creating value for our customers, which we believe is the key to creating value for our investors. To accomplish our objective, we focus on the following key strategies:

1. Expand existing core asset platforms

    - We intend to develop and acquire energy transportation assets and related facilities that are complementary to our existing systems. Our core businesses provide plentiful opportunities to achieve our primary business objectives.

2. Develop new asset platforms

    - We plan to develop new gathering, processing, transportation and storage assets to meet customer needs, by expanding capacity into new markets with favorable supply and demand fundamentals.

3. Focus on operational excellence

    - We will continue to operate our existing infrastructure to maximize cost efficiencies, provide flexibility for our customers and ensure the capacity is reliable and available when required. We will focus on safety, environmental integrity, innovation and effective stakeholder relations.

In our current environment, our primary focus is on expanding and developing our existing assets. We continue to place relatively less emphasis on acquisitions than we have in past years due to:

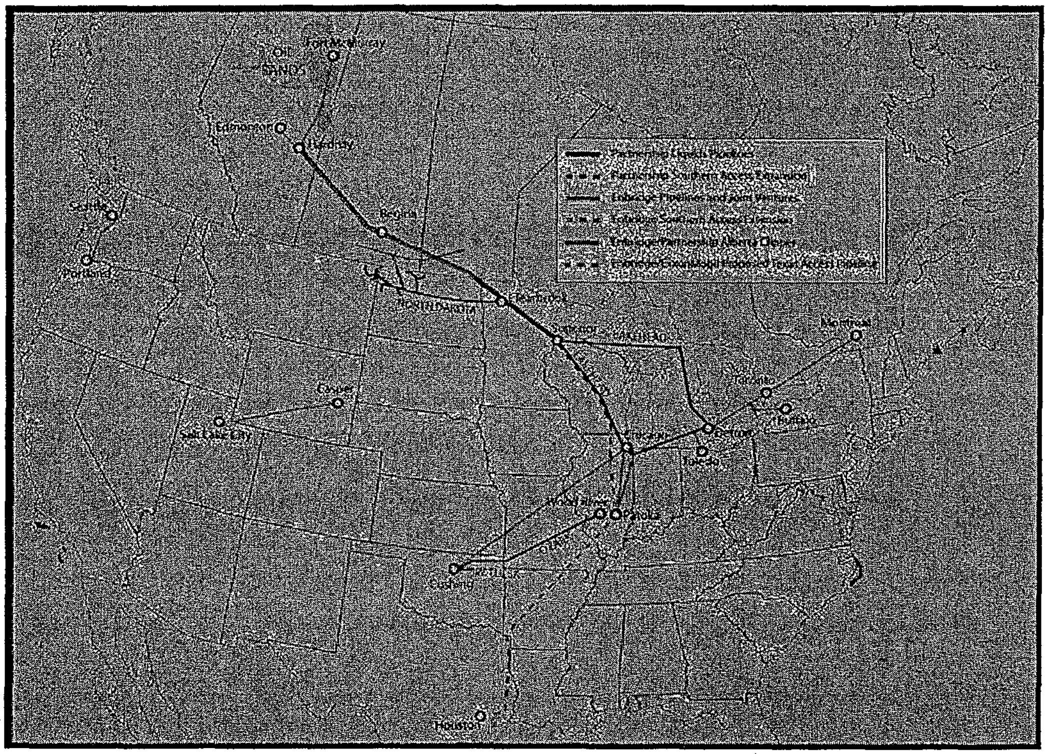
- Acquisition prices for the stable energy assets we seek continue to be inflated; and
- The expansion and diversification of our asset base over the past few years has created opportunities for internal growth projects that are expected to enhance the value of services we provide to our customers and returns to our investors.

While purchase prices remain high, our acquisitions will likely be limited to situations where we have natural advantages, through reduced costs or increased utilization of our services.

Our planned internal growth for both our liquids and natural gas businesses will require a significant investment of expansion capital over the next few years. While these major projects are under construction, we will bear the associated capital costs for these investments before we begin to realize a return on them. We expect our larger growth projects will be accretive to distributable cash flow when placed into service. These projects are discussed below in the respective business section.

Liquids

The following map presents the locations of our current Liquids systems assets and projects being constructed:



This map depicts some assets owned by Enbridge and projects being constructed to provide an understanding of how they interconnect with our Liquids systems.

Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2007 from the U.S. Department of Energy's Energy Information Administration, Canada supplied approximately 1.7 million barrels per day, or Bpd, of crude oil to the U.S., the largest source of U.S. imports. Approximately 67 percent of the Canadian crude oil moving into the U.S. was transported on the System, the primary pipeline from western Canada to the U.S. We are well positioned to develop additional infrastructure to deliver growing volumes of crude oil that are expected from the Alberta oil sands. With an estimated $110 billion in Canadian dollars, or CAD, of active or planned projects in the Alberta oil sands, new production is expected to grow steadily during the next five years, with an additional 2.3 million Bpd of incremental supply available by 2015, according to the Canadian Association of Petroleum Producers, or CAPP.

Our Southern Access project is the cornerstone of our mainline expansion initiatives to address the expected increase in supply of Western Canadian crude oil. Our $2.1 billion project will provide an additional 400,000 Bpd of heavy crude oil capacity to the Chicago market and beyond by early 2009, with nearly half of this capacity available in early 2008. The design will also permit a further 800,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior. The Southern Access project involves new pipeline construction on our Lakehead system along with expansion on the Canadian portion of the pipeline by Enbridge.

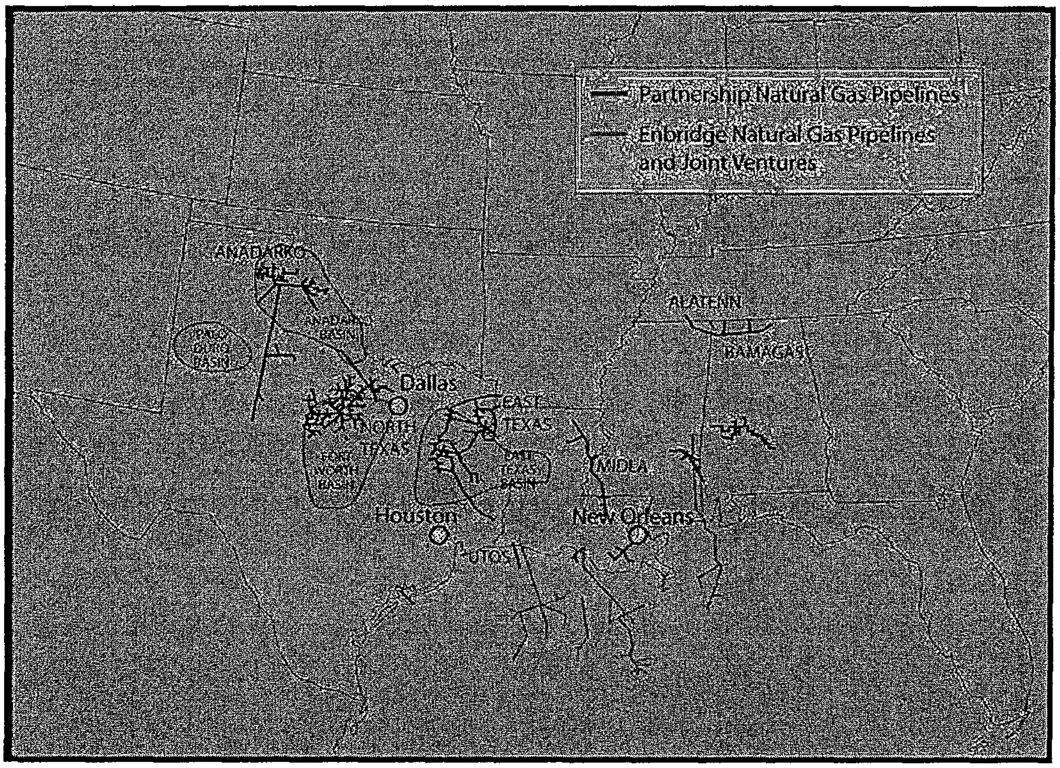
Additionally, we and Enbridge are developing the Alberta Clipper pipeline project, which will involve construction of a 1,000 mile, 36-inch diameter, heavy crude oil pipeline from Hardisty, Alberta to Superior, Wisconsin with an initial capacity of 450,000 Bpd that is expandable to 800,000 Bpd. Our share of the cost of this project as currently proposed will be approximately $1.0 billion in 2007 dollars, excluding capitalized interest. Alberta Clipper is expected to be in-service by the middle of 2010. Regulatory applications were filed with the National Energy Board in May 2007 for the Canadian segment of the project, and the hearings were concluded in the fourth quarter of 2007. In the United States, regulatory and permit applications are in progress at state and federal levels, and engineering and public consultations are underway.

Along with Enbridge, we are actively working with our customers to develop options that will allow Canadian crude oil to access new markets. The market strategy we are undertaking is to provide timely, economical, integrated transportation solutions to connect growing supplies of production from the Alberta oil sands to key refinery markets in the United States. The strategy involves further penetration into PADD II as well as entry into the vast refining center of the U.S. Gulf Coast. In December 2007, Enbridge and ExxonMobil Pipeline Company announced the two companies will conduct a Solicitation for Binding Shipper Commitment (Commitment Solicitation) for a proposed new pipeline system to transport crude oil from Patoka, Illinois, to the Texas Gulf Coast. The new pipeline to be called the "Texas Access Pipeline," would transport crude oil sourced from the Canadian oil sands region in Alberta, Canada, and from the upper Midwest to refiners in the Nederland and Houston, Texas areas. The proposed project includes a new 768-mile, 30-inch diameter pipeline, which would transport crude oil from Patoka, Illinois, southward to Nederland, Texas. Also proposed is an 88-mile, 24-inch pipeline to transport crude oil onward from Nederland to a delivery point in the east Houston area. The Commitment Solicitation is for shipper interest in executing binding commitments to transport specified volumes of crude oil on the new pipeline, which is expected to be completed in 2011. The results of the Commitment Solicitation will guide and determine the further development of the proposed joint venture pipeline.

The strategy of further penetration into PADD II is also evidenced by the Enbridge expansion of the Spearhead pipeline system from 125,000 Bpd to 190,000 Bpd. Our Lakehead system carries Western Canadian crude oil as far as Chicago, where it is transferred to the Spearhead pipeline that runs from Chicago, Illinois to the refinery and storage hub located at Cushing, Oklahoma.

Natural Gas

The following map presents the locations of assets for our Natural Gas systems:



This map depicts some assets owned by Enbridge to provide an understanding of how they relate to our Natural Gas systems.

Our natural gas assets are primarily located in the U.S. Gulf Coast region, one of the most active natural gas producing areas in the United States. Three of our larger systems in Texas are located in basins that are experiencing consistent drilling and production growth. These core basins are known as the East Texas basin, the Fort Worth Basin and the Anadarko basin. Our focus has been on expanding the service capability of our existing assets and acquiring assets with strong growth prospects located in or near these areas where we already operate or have a competitive advantage.

One of our key goals is to become the premier midstream energy company in the U.S. Gulf Coast region. To achieve this end, the operations and commercial activities of our gathering and processing assets and intrastate pipelines are integrated to provide better service to our customers. From an operations perspective, our key strategies are to provide safe and reliable service at reasonable costs to our customers, enhance our reputation and capitalize on opportunities for attracting new customers. From a commercial perspective, our focus is to provide our customers with a greater value for their commodity. This latter objective we intend to achieve by increasing customer access to preferred natural gas markets. We have made significant progress on attaining this objective with construction of our East Texas Expansion project, otherwise known as Clarity, which includes an intrastate pipeline connecting our East Texas system at Bethel, Texas to multiple downstream interconnects and by physically connecting a number of our systems.

The aim is to be able to move significant quantities of natural gas from our Anadarko, North Texas and East Texas systems to the major market hubs in Texas and Louisiana, which Clarity provides. From these market hubs, natural gas can be used in the local Texas markets or transported to consumers in the Midwest, Northeast and Southeast United States.

Our Natural Gas business also includes trucking operations that we use to enhance the value of the NGLs produced at our processing plants by ensuring ready access to strategic markets. Our Marketing business provides us with the ability to maximize the value received for the natural gas we transport and purchase by identifying customers with consistent demand for natural gas.

The growth prospects in our core areas are primarily a result of strong commodity prices, rig utilization rates and improvements in technology to produce natural gas from tight sand and shale formations. As a result, many expansions and extensions have been made on three of our main gathering and processing systems in Texas, including well-connects, processing plant re-activations, new plant construction, added compression, new pipelines and treating plant re-activations.

We continue to work closely with our customers to provide natural gas transportation solutions to avoid shut-in natural gas production from insufficient transportation capacity. In January 2006, we announced an expansion and extension of our East Texas system to handle the strong growth occurring in East Texas natural gas production, particularly from the Bossier Sands and other regional producing formations. We coordinated extensively with our customers to develop and enhance access for growing Texas natural gas production to major markets in southeast Texas. We have firm volume commitments and acreage dedications on our Clarity project, which we believe by the end of 2008 will approximate 600 MMcf/d. The intrastate pipeline has 700 MMcf/day of capacity that will be available when construction is completed in early 2008 and additional compression is added in mid-2008. The project is designed to be expandable and is positioned for potential upstream and downstream extension.

In addition to the expansion of our transportation capacity to meet the needs of our customers, we have also expanded our processing and treating capacity on our three major systems to meet the growing demand for these services and to capture the additional revenue these services provide. In 2007 we added 195 MMcf/d of processing capacity with the commissioning of the Hidetown plant on our Anadarko system and the expansions of the Weatherford plant on our North Texas system. We added three hydrocarbon dewpoint control facilities with total capacity of 550 MMcf/d on our East Texas system at Carthage, Grapeland and Henderson, Texas to meet the increasingly more stringent natural gas pipeline transportation specifications. Lastly, we enhanced the ability of our 275 MMcf/d treating facility at Aker, Texas to handle additional sour gas being produced in the southeast Texas area and we commissioned our 200 MMcf/d treating facility at Marquez, Texas which feeds directly into the intrastate pipeline we are constructing in connection with our Clarity project.

BUSINESS SEGMENTS

We conduct our business through three business segments:

- Liquids;
- Natural Gas; and
- Marketing.

These segments have unique business activities that require different operating strategies. For information relating to revenues from external customers, operating income and total assets for each segment, refer to Note 16 of our consolidated financial statements beginning on page F-1 of this report.

Liquids Segment

Lakehead system

The Lakehead system consists primarily of a crude oil and liquid petroleum common carrier pipeline and terminal assets in the Great Lakes and Midwest regions of the United States. This system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. The System, which spans approximately 3,300 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The System serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. We and Enbridge have undertaken the Southern Access, Alberta Clipper and other expansion projects to increase the capacity of the Lakehead and Enbridge mainline systems in an effort to capitalize on the expected increases in crude oil supplies from previously announced heavy crude oil and oil sands projects in the Province of Alberta, Canada.

Our Lakehead system is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission, or FERC. The Lakehead system spans a distance of approximately 1,900 miles, and consists of approximately 3,500 miles of pipe with diameters ranging from 12 inches to 48 inches, 60 pump station locations with a total of approximately 846,450 installed horsepower and 64 crude oil storage tanks with an aggregate capacity of approximately 11.6 million barrels. The System operates in a segregation, or batch mode, allowing the transport of 43 crude oil commodities including light, medium and heavy crude oil (including bitumen, which is a naturally occurring tar-like mixture of hydrocarbons), condensate and NGLs.

Customers. Our Lakehead system operates under month-to-month transportation arrangements with our shippers. During 2007, approximately 30 shippers tendered crude oil and liquid petroleum for delivery through the Lakehead system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Lakehead system. Our customers include integrated oil companies, major independent oil producers, refiners and marketers.

Supply and Demand. Our Lakehead system is well positioned as the primary transporter of western Canadian crude oil and continues to benefit from the growing production of crude oil from the Alberta oil sands. Similar to U.S. domestic conventional crude oil production, western Canada's conventional crude oil production is declining. Over the last several years, development of the Alberta oil sands resource has more than offset declining conventional production. The NEB estimated that total production in 2007 from the Western Canadian Sedimentary Basin, or WCSB, averaged approximately 2.4 million Bpd compared with 2.3 million bpd in 2006. WCSB crude oil production is comparable with production from key OPEC members Kuwait and Venezuela.

Remaining established conventional oil reserves in western Canada were estimated to be approximately 3.7 billion barrels at the end of 2006. During 2006, the latest period for which data is available, approximately 66 percent of conventional production was replaced with reserve additions. Remaining established reserves from the Alberta oil sands as of the end of 2006 stand at approximately 173 billion barrels. Combined conventional and oil sands established reserves of approximately 179 billion barrels compares with Saudi Arabia's proved reserves of approximately 264 billion barrels.

According to the CAPP, an estimated $60 billion CAD has been spent on oil sands development from 1996 through 2006. A survey of CAPP members and oil sands developers estimate that oil producers may spend an additional $110 billion CAD by 2011, including all announced and planned oil sands projects. Although it is unlikely that all projects will proceed as planned, the investment already in place and the number and size of companies involved provides strong evidence of ongoing oil sands industry expansion. CAPP estimates future production from the Alberta oil sands will increase by more than 2.3 million barrels per day by 2015 based on a subset of currently approved applications and announced expansions.

The near-term growth in crude oil supply comes from the completion and consolidation of major expansion projects at existing synthetic crude oil upgraders and growth of bitumen production from both existing and new Steam Assisted Gravity Drainage, or SAGD facilities currently under construction. Over the next year, synthetic crude oil production is expected to increase by approximately 315,800 Bpd from the following sources:

- 46,300 Bpd from the start up of the first phase of the Heartland Upgrader by BA Energy Inc.
- 114,000 Bpd from the phase 1 start up by Canadian Natural Resources Limited of its Horizon Project Upgrader.
- 58,500 Bpd from the phase 1 start up the Long Lake Project upgrader by joint venture partners Nexen Inc. and OPTI Canada Inc.
- 97,000 Bpd from start up of the Millennium coker unit by Suncor Energy Inc.

Syncrude completed a 100,000 Bpd Stage 3 expansion in 2006, increasing total production capacity to 350,000 Bpd. However, the new Stage 3 coker suffered from a number of start-up issues that prevented Syncrude from attaining full utilization of its production capacity, even through 2007. Production for the year averaged approximately 304,000 Bpd. Syncrude's next expansion will de-bottleneck the current system to increase synthetic production by approximately 40,000 Bpd to approximately 390,000 Bpd by 2012.

Suncor completed its 35,000 Bpd expansion in late 2005 resulting in total upgrading capacity of 260,000 Bpd. Average synthetic production from the upgrader was 229,000 Bpd in 2007, lower than capacity as a result of the scheduled shutdown of one of two upgraders to allow the tie-in of new facilities related to a planned expansion. Suncor also received conditional approval from the AEUB for its proposed Voyageur expansion, which will increase synthetic production capacity to 550,000 Bpd by 2012. Over the next year, Suncor is planning to complete construction of an additional coker unit as part of its Millennium project, bringing an additional 97,000 Bpd of synthetic production to the market.

The Athabasca Oil Sands Project, or AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Marathon Oil Corporation (20%), is another oil sands project that reached full production capacity in 2004. The AOSP project moved forward with AEUB's conditional approval of the proposed AOSP Expansion 1 project in 2006. The AOSP Expansion 1 project aims to achieve an expansion from the current production capacity of 158,000 Bpd of synthetic crude oil to more than 249,000 Bpd by 2010.

Over the next two years, unblended bitumen production is expected to start, or increase, from more than ten individual projects that are coming on line. Notable projects include the expansions at Canadian Natural's Wolf Lake/Primrose area, ConocoPhillips' Surmont, Devon's Jackfish, EnCana's Foster Creek and Christiana Lake, Husky's Sunrise, Suncor's Firebag and Total's Josyln project. Based on the AEUB forecast, unblended bitumen production is expected to increase by roughly 38,000 Bpd by the end of 2008, more than offsetting the decline in conventional crude production.

Although the crude oil and liquid petroleum delivered through the Lakehead system primarily originates in oilfields in western Canada, the Lakehead system also receives approximately five percent of its receipts from domestic sources including:

- U.S. production at Clearbrook, Minnesota through a connection with the North Dakota system;
- U.S. production at Lewiston, Michigan; and
- both U.S. and offshore production in the Chicago area.

Based on forecasted growth in western Canadian crude oil production and completion of upgrader expansions and increased bitumen production, Lakehead system deliveries are expected to average 1.69 million Bpd in 2008 compared with 1.54 million Bpd in 2007. The estimated deliveries for 2008 are part of a forecast representing forward-looking information and are subject to risks, uncertainties, and factors beyond our control.

Our ability to increase deliveries and to expand our Lakehead system in the future will ultimately depend upon numerous factors. The investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices, future operating costs, and availability of markets for produced crude. Higher crude oil production from the WCSB should result in higher deliveries on the Lakehead system. Deliveries on the Lakehead system are also affected by periodic maintenance, turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, our Lakehead system.

We expect the demand for WCSB crude oil production will continue to increase in PADD II. Refinery configurations and crude oil requirements in PADD II continue to be an attractive market for Western Canadian supply. According to the U.S. Department of Energy's Energy Information Administration, 2007 demand for crude oil in PADD II declined slightly from 2006 with an average of 3.2 million Bpd. At the same time, production of crude oil within PADD II increased marginally by 12,000 Bpd to 469,000 Bpd. With the proximity of the WCSB to PADD II, the availability of capacity on the Lakehead system and limited alternative markets for WCSB production, we expect deliveries on the Lakehead system to increase along with increases in WCSB supply. Based on our industry survey, we expect refineries in the PADD II market to compete aggressively with new markets for access to the growing supply of crude oil from the WCSB.

In conjunction with Enbridge, we continue to progress on schedule with construction of the 400,000 Bpd Southern Access expansion project. We are undertaking the United States portion of the expansion on our Lakehead system. The first stage of construction is on schedule for completion in the first half of 2008 that will add approximately 190,000 Bpd. This stage of the project includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment. The second stage of the Southern Access expansion project will provide capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in the first half of 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

On March 16, 2006, the Federal Energy Regulatory Commission ("FERC") approved an Offer of Settlement with respect to rate principles for the Southern Access expansion, which were negotiated with CAPP. In July 2006, support from shippers and CAPP was obtained to increase the diameter of the new pipeline segment of the project from 36 inches to 42 inches. The larger diameter will not provide increased capacity in the near term but does increase the ultimate expansion capacity of the line from 800,000 Bpd to 1,200,000 Bpd with additional pumping horsepower. This improves future expansion opportunities for our Lakehead system. In the interim, shippers will absorb all of the incremental operating costs of the larger diameter pipe but will benefit from reduced power costs at higher throughput levels.

We anticipate the ultimate cost to complete our portion of the Southern Access project to approximate $2.1 billion. This estimate reflects our cost experience to date for labor, materials and rights-of-way. The risk to our unitholders resulting from any escalation of costs is largely mitigated by the cost of service tolling arrangement used for the project. Approximately 88 percent of cost overages will be included in the rate base, which forms the basis for determining our tariff rates for transportation. The remaining 12 percent of the project cost relates to installing larger pipe than required under current agreements, which we are financing in anticipation of future expansion opportunities.

In July 2006, Enbridge announced that it had received support from shippers and CAPP for its 36-inch diameter, 400,000 Bpd Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. The project will be undertaken by Enbridge; however, we will benefit from the incremental volumes moving through our Lakehead system to connect with this extension. The initial FERC Offer of Settlement filed in September 2006 was rejected by the FERC due to the rolled in rate design contained in the Offer of Settlement. However, as a result of the strong support for the project, Enbridge filed a second application with the FERC in the latter half of 2007 with an alternative tolling structure to address the initial opposition from the intervening parties. A decision by the FERC is expected in early 2008 to allow the project to continue on schedule, with a 2009 in-service date.

Forecasts of oil sands production growth developed by Enbridge, as well as by CAPP, indicate that additional export pipeline capacity out of Western Canada will be needed over and above projects currently under construction. As a result of these forecasts and support received from shippers, we and Enbridge are developing the Alberta Clipper project. This project involves construction of a 36-inch diameter 1,000 mile heavy crude oil pipeline from Hardisty, Alberta to Superior generally within or adjacent to our and Enbridge's existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior, and at the request of our customers, we have revised the scope to include a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pumping stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the United States segment of the project will approximate $1.0 billion (in 2007 dollars excluding capitalized interest). Alberta Clipper is expected to be in service by mid-2010.

In May 2007, Enbridge filed an application with Canada's National Energy Board, or NEB, for the construction and operation of the Canadian segment of the project. In June 2007 Enbridge filed supplements to this application setting forth the tolling principles of the Canadian portion of the project, which are supported by CAPP and the hearings were concluded in the forth quarter of 2007. The United States regulatory and permit applications are in progress at state and federal levels. Enbridge is also progressing with land access, engineering and initial procurement commitments to facilitate commencement of project construction.

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Chicago to Cushing. The pipeline, renamed Spearhead, began delivering Canadian crude oil to the major oil hub at Cushing in March 2006 and has operated at or near its capacity of 125,000 Bpd. We have benefited from Western Canadian crude oil being carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline. On March 2, 2007, Enbridge initiated a binding open season for expansion of the pipeline to 190,000 Bpd, which was successfully concluded in late April with receipt of binding commitments for capacity in excess of 30,000 Bpd. Preliminary engineering design has been completed, and the expansion is expected to be completed by early 2009. This project will be complementary to our Lakehead system.

In April 2006, ExxonMobil announced it had completed the reversal of two of its crude oil pipelines allowing up to 66,000 Bpd of Canadian crude oil to flow from Patoka, Illinois to the U.S. Gulf Coast. The pipeline is linked to our Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka, Illinois. The Mustang system is 30% owned by an affiliate of Enbridge. ExxonMobil has received firm commitments from Canadian shippers for an average of 50,000 Bpd of capacity on the lines from Patoka, to Nederland, Texas for the next five years. The connection of our Lakehead system with this new market should also support increased throughput on our Lakehead system, although the reversed ExxonMobil system is also capable of transporting western Canadian crude oil moved via other competing pipelines into the Patoka market.

In December 2007, Enbridge and ExxonMobil Pipeline Company announced that they will jointly conduct a Solicitation for Binding Shipper Commitment for a proposed new pipeline system, to transport crude oil from Patoka, Illinois, to the Texas Gulf Coast. The new pipeline, to be called the "Texas Access

Pipeline," will transport crude oil sourced from the Canadian oil sands region in Alberta, Canada, and from the upper Midwest to refiners in the Nederland and Houston, Texas areas. The proposed project includes a new 768-mile, 30-inch diameter pipeline, which would transport crude oil from Patoka, Illinois, southward to Nederland, Texas. Also proposed is an 88-mile, 24-inch pipeline to transport crude oil onward from Nederland to a delivery point in the east Houston area. The Commitment Solicitation is for shipper interest in executing binding commitments to transport specified volumes of crude oil on the new pipeline, which is expected to be completed in 2011. The results of the Commitment Solicitation will guide and determine the further development of the proposed joint venture pipeline project.

Competition. Our Lakehead system, along with the Enbridge system, is the main crude oil export route from the WCSB. WCSB production in excess of western Canadian demand moves on existing pipelines into the Midwest area of the United States (PADD II), the Rocky Mountain states (PADD IV), the Anacortes area of Washington State (PADD V), and the U.S. Gulf Coast (PADD III). In each of these regions, WCSB crude oil competes with local and imported crude oil. As local crude oil production declines and refineries demand more imported crude oil, imports from the WCSB should increase.

For 2007, the latest data available shows that PADD II total demand was 3.2 million Bpd while it produced only 469,000 Bpd, and thus imported 2.7 million Bpd. The latest available data for 2007 indicate PADD II imported approximately 1.1 million Bpd of crude oil from Canada, a majority of which was transported on our Lakehead system to destinations in PADD II and to other pipeline systems with PADD III destinations. The remaining 1.6 million Bpd was imported from PADDs III and IV as well as from offshore sources through the U.S. Gulf Coast. Lakehead system deliveries of Canadian crude oil to PADD II were level with delivery volumes for 2006. Total deliveries on our Lakehead system averaged 1.53 million Bpd in 2007, meeting approximately 71 percent of Minnesota refinery capacity; 60 percent of the greater Chicago area; and 67 percent of Ontario's refinery demand.

Considering all of the pipeline systems that transport western Canadian crude oil out of Canada, the System transported approximately 67 percent of the total western Canadian crude oil exports in 2007 to the United States. The remaining production was transported by systems serving the British Columbia, PADD II, PADD IV, and PADD V markets.

Given the expected increase in crude oil production from the Alberta oil sands over the next 10 years, alternative transportation proposals have been presented to crude oil producers. These proposals range from expansions of existing pipelines that currently transport western Canadian crude oil, to new pipelines and extensions of existing pipelines. These proposals are in various stages of development, with some at the concept stage and others that are proceeding with regulatory approval. Some of these proposals could be in direct competition with our Lakehead system.

Enbridge has proposed construction of the Gateway Pipeline with an in-service date in the 2012 to 2014 timeframe, which includes both a condensate import pipeline and a petroleum export pipeline. The condensate line would transport imported diluent from Kitimat, British Columbia to the Edmonton, Alberta area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat and would compete with our Lakehead system for production from the Alberta oil sands.

We and Enbridge believe that the Southern Access Expansion Program, the Alberta Clipper Project, and other initiatives to provide access to new markets in the Midwest, Mid-continent and Gulf Coast, offer flexible solutions to future transportation requirements of western Canadian crude oil producers, and the in-service timing of these solutions is in line with prospective shipper needs.

The following provides an overview of other proposals put forth by competing pipeline companies that are not affiliated with Enbridge:

- The construction of a new 24-inch pipeline alongside an existing pipeline which begins in Clearbrook, Minnesota and transports western Canadian crude oil to St. Paul, Minnesota. This expansion will have 165,000 Bpd initial capacity and 350,000 Bpd ultimate capacity. Construction began in summer 2007, with an anticipated completion date in 2008. While throughput on our Lakehead system would benefit from this expansion, volumes moving on our Lakehead system could be negatively impacted if the geographic reach of this pipeline were extended by reversing an existing Wood River to St. Paul pipeline.

- The expansion of an existing pipeline that runs from Alberta to British Columbia and Washington State. The first phase of this expansion to add 35,000 Bpd of capacity was approved by the NEB in 2005 and was recently completed. The second phase received NEB approval in October 2006, and would further increase capacity by another 40,000 Bpd by the end of 2008. Additional phases have also been proposed which would add substantial additional capacity, however, these proposed phases have not yet received shipper support.

- Construction of a new 435,000 Bpd crude oil pipeline from Hardisty, Alberta to Wood River and Patoka, with an expected in-service date of late 2009. This proposal has support of long-term contracts for a total of 340,000 Bpd. The sponsor company filed applications with the NEB in June 2006 to convert part of its mainline gas transmission facilities, and in December 2006, for approval to operate and construct facilities in Canada. Public hearings on the gas line transfer application were held in mid-November 2006 and in early 2007 the NEB approved transfer of the gas transmission facilities to crude oil service, and in September 2007 the NEB approved the application to construct and operate a 435,000 Bpd crude oil pipeline. Additional approvals will be required from United States and Canadian regulatory authorities before the project can proceed. A successful open season was held in the early part of 2007 for an expansion to 590,000 Bpd and an extension to Cushing, Oklahoma. A variety of regulatory approvals will be required in the United States at state and local levels before the proposal can proceed.

- Construction of new crude oil pipelines from northern Alberta directly to the U.S. Gulf Coast have been proposed by several different companies including Enbridge. These conceptual pipeline proposals are subject to shipper support and regulatory approval.

These competing alternatives for delivering western Canadian crude oil into the United States and other markets could erode shipper support for further expansion of our Lakehead system beyond the Southern Access Expansion and Extension projects and the Alberta Clipper Project. They could also affect throughput on and utilization of the System. However, the Lakehead and Enbridge systems offer significant cost savings and flexibility advantages, which are expected to continue to favor the System as the preferred alternative for meeting shipper transportation requirements to the Midwest United States and beyond.

The following table sets forth average deliveries per day and barrel miles of our Lakehead system for each of the periods presented.

	Deliveries				
	2007	2006	2005	2004	2003
	(thousands of Bpd)				
United States					
Light crude oil	346	327	241	275	258
Medium and heavy crude oil	852	872	791	785	741
NGL	4	5	4	4	4
Total United States	1,202	1,204	1,036	1,064	1,003
Ontario					
Light crude oil	184	160	146	174	174
Medium and heavy crude oil	62	63	59	81	68
NGL	95	90	98	103	109
Total Ontario	341	313	303	358	351
Total Deliveries	1,543	1,517	1,339	1,422	1,354
Barrel miles (billions per year)	408	400	338	367	345

Mid-Continent system

Our Mid-Continent system, which we acquired in the first quarter of 2004, is located within the PADD II district and is comprised of our Ozark pipeline, our West Tulsa pipeline and storage terminals at Cushing and El Dorado, Kansas. It includes over 480 miles of crude oil pipelines and 16.7 million barrels of crude oil storage capacity. Our Ozark pipeline transports crude oil from Cushing to Wood River where it delivers to ConocoPhillips' Wood River refinery and interconnects with the WoodPat Pipeline, and the Wood River Pipeline, each owned by unrelated parties. Our West Tulsa pipeline moves crude oil from Cushing to Tulsa, Oklahoma where it delivers to Sinclair Oil Corporation's Tulsa refinery.

The storage terminals consist of 104 individual storage tanks ranging in size from 55,000 to 575,000 barrels. We added a net of 7 new tanks during 2007 to our existing storage facilities in Cushing, which increased our crude oil storage capacity to 16.7 million. A portion of the storage facilities are used for operational purposes while we contract the remainder of the facilities with various crude oil market participants for their term storage requirements. Contract fees include fixed monthly capacity fees as well as utilization fees, which we charge for injecting crude oil into and withdrawing crude oil from the storage facilities.

Customers. Our Mid-Continent system operates under month-to-month transportation arrangements and both long-term and spot storage arrangements with its shippers. During 2007, approximately 40 shippers tendered crude oil for service by the Mid-Continent system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Average deliveries on the system were 236,000 Bpd for 2007 and 244,000 Bpd for 2006.

Supply and Demand. The Mid-Continent system is positioned to capitalize on increasing near-term demand for imported crude oil from west Texas and the U.S. Gulf Coast as well as third-party storage demand. In 2007, PADD II imported 2.7 million Bpd from outside of the PADD II region. The Lakehead system supplied roughly 1.1 million Bpd of crude from Canada leaving 1.6 million Bpd imported from PADDs III and IV as well as offshore sources. We expect the gap between local supply and demand for crude oil in PADD II to continue to widen, encouraging imports of crude oil from Canada, PADD III, and foreign sources.

Competition. Our Ozark pipeline system currently serves an exclusive corridor between Cushing and Wood River. However, refineries connected to Wood River have crude supply options available from Canada via the Lakehead system, with a connection to the Mustang pipeline, an Enbridge affiliated system, and through a third party pipeline, which runs from western Canada and PADD IV. These same refineries also have access to U.S. Gulf Coast and foreign supply through the Capline pipeline system, which is an undivided joint interest pipeline that is owned by unrelated parties. In addition, refineries located east of Patoka with access to crude through the Ozark system, also have access to west Texas supply through the Texas Gulf pipeline owned by unrelated parties. The Ozark pipeline system could face a significant increase in competition if a proposed new pipeline from Hardisty, Alberta to Patoka is completed in 2009. However, if that situation occurs, we would consider potential alternative uses for our Ozark system.

In addition to movements into Wood River, crude oil in Cushing is transported to Chicago and El Dorado on third-party pipeline systems. With the reversal of the Spearhead pipeline, western Canadian crude oil moving on Spearhead is increasing the importance of Cushing as a terminal and pipeline origination area.

The storage terminals rely on demand for storage service from numerous oil market participants. Producers, refiners, marketers and traders rely on storage capacity for a number of different reasons: batch scheduling, stream quality control, inventory management, and speculative trading opportunities. Competitors to our storage facilities at Cushing include large integrated oil companies and other midstream energy partnerships.

North Dakota system

Our North Dakota system is a crude oil gathering and interstate transportation system servicing the Williston Basin in North Dakota and Montana. Its crude oil gathering pipelines collect crude oil from points near producing wells in approximately 22 oil fields in North Dakota and Montana. Most deliveries from the North Dakota system are made at Clearbrook, Minnesota, to the Lakehead system and to a third-party pipeline system. The North Dakota system includes approximately 330 miles of crude oil gathering lines connected to a transportation line that is approximately 620 miles long, with a capacity of approximately 110,000 Bpd. We recently completed a 30,000 Bpd increase in capacity resulting from a $78.2 million expansion of the system we began in 2006 and completed in December 2007. This expansion was necessary to meet increased crude oil production from the Montana and North Dakota region. We have also proposed an approximate $150 million additional expansion to further increase system capacity to 161,000 Bpd. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing tariff rates. The proposed surcharge is similar to the structure being used on the recently completed expansion project and is subject to approval from the FERC. The North Dakota system also has 21 pump stations, one delivery station, and 11 terminaling facilities with an aggregate working storage capacity of approximately 745,000 barrels.

Customers. Customers of the North Dakota system include producers of crude oil and purchasers of crude oil at the wellhead, such as marketers, that require crude oil gathering and transportation services. Producers range in size from small independent owner/operators to the largest integrated oil companies.

Supply and Demand. Like the Lakehead system, the North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States, and the ability of crude oil producers to maintain their crude oil production and exploration activities.

Competition. Competitors of the North Dakota system include integrated oil companies, interstate and intrastate pipelines or their affiliates and other crude oil gatherers. Many crude oil producers in the oil fields served by the North Dakota system have alternative gathering facilities available to them or have the ability to build their own facilities.

Natural Gas Segment

We own and operate natural gas gathering, treating, processing and transportation systems as well as trucking operations. We purchase and gather natural gas from the wellhead, deliver it to plants for treating and/or processing and to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies.

Natural gas treating involves the removal of hydrogen sulfide, carbon dioxide, water and other substances from raw natural gas so that it will meet the standards for pipeline transportation. Natural gas processing involves the separation of raw natural gas into residue gas and NGLs. Residue gas is the processed natural gas that ultimately is consumed by end users. NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a process known as fractionation, and sold as their individual components, including ethane, propane, butanes and natural gasoline. At December 31, 2007, we have 10 active treating plants and 24 active processing plants, including three hydrocarbon dewpoint control facilities, or HCDP plants. Our treating facilities have a combined capacity exceeding 1,050 MMcf/d while the combined capacity of our processing facilities approximates 1,800 MMcf/d, including 550 MMcf/d provided by the HCDP plants.

Our natural gas segment consists of the following systems:

- East Texas system: Includes approximately 3,800 miles of natural gas gathering and transportation pipelines, eight natural gas treating plants and seven natural gas processing plants, including three HCDP plants and approximately 250 miles associated with completed sections of our Clarity project.
- Anadarko system: Consists of approximately 1,700 miles of natural gas gathering and transportation pipelines in southwest Oklahoma and the Texas panhandle, one natural gas treating plant and six natural gas processing plants. The Anadarko system includes the Palo Duro system, which we acquired in March 2004.
- North Texas system: Includes approximately 4,500 miles of natural gas gathering pipelines and ten natural gas processing plants.
- Our transportation operations include three FERC-regulated natural gas interstate pipeline systems which include the Midla, AlaTenn and UTOS pipelines. Each of these natural gas pipeline systems typically consists of a natural gas pipeline, compression, and various interconnects to other pipelines that serve wholesale customers.
- Our transportation operations also include a number of smaller non-FERC regulated natural gas pipelines and plants as well as trucking operations which are discussed below.

Customers. Customers of our natural gas pipeline systems include both purchasers and producers of natural gas. Purchasers are comprised of marketers, including our Marketing business, and large users of natural gas, such as power plants, industrial facilities and local distribution companies. Producers served by our systems consist of small, medium and large independent operators and large integrated energy companies. We sell NGLs resulting from our processing activities to a variety of customers ranging from large petrochemical and refining companies to small regional retail propane distributors.

Our natural gas pipelines serve customers predominantly in the Gulf Coast and southeastern regions of the United States. Customers include large users of natural gas, such as power plants, industrial facilities, local distribution companies, large consumers seeking an alternative to their local distribution company, and shippers of natural gas, such as natural gas producers and marketers.

Supply and Demand. Demand for our gathering, treating and processing services primarily depends upon the supply of natural gas reserves and the drilling rate of new wells. The level of impurities in the natural gas gathered also affects treating services. Demand for these services also depends upon overall economic conditions and the prices of natural gas and NGLs. Our larger systems, Anadarko, East Texas and North Texas, are located in basins that continue to experience growth in natural gas drilling and production.

Our East Texas system is primarily located in the East Texas Basin. The Bossier trend, which is located on the western side of our East Texas system within the East Texas Basin, continues to experience substantial growth. Production in the Bossier trend has grown from under 390 MMcf/d in 1997 to over 1,500 MMcf/d in August 2007. During 2006, the link between our North Texas and East Texas systems became fully operational and increased the utilization of the 500 MMcf/d intrastate pipeline that we placed in service in June 2005 on our East Texas system by providing additional market access to customers of our North Texas system. In a further effort to address the continuing strong growth in natural gas production occurring in East Texas, in early 2006 we initiated a $635 million expansion and extension of our East Texas system named the Clarity project. During 2007, we completed the following segments of this expansion project:

- A 24-inch diameter pipeline that runs from the Marquez treating facility to Crockett, Texas and the 36-inch diameter pipeline that runs from Crockett to Goodrich, Texas were both completed and placed into service in late March 2007;
- The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed into service in March 2007;
- A 36-inch diameter pipeline that extends from an interconnect with our existing pipeline at Bethel, Texas to Crockett was completed and placed into service in late July 2007; and
- A 36-inch diameter pipeline that extends from Goodrich to Kountze, Texas, which enables deliveries into a major interstate pipeline was completed in October 2007.

We expect construction of the remaining segments that will connect natural gas supply from Bethel to Orange, Texas will be completed in the first quarter of 2008. Additional capacity to downstream interconnects will increase as compression is added through mid-2008. Completion of our Clarity project will provide service to major industrial companies in Southeast Texas with interconnects to interstate pipelines, intrastate pipelines and wholesale customers. We have firm volume commitments and acreage dedications which we believe will approximate 600 MMcf/d of the 700 MMcf/d of capacity by the end of 2008 and we continue to pursue additional commitments for capacity on the pipeline. The Clarity project is designed to be expandable and is positioned for potential upstream and downstream extension to meet the growing demand for natural gas transportation capacity.

We have also completed significant expansion of our treating and processing capacity in the region, which began in 2006 with the completion of our 120 MMcf/d Henderson natural gas processing facility. We completed the following additional facilities during 2007:

- Enhancement of our existing 275 MMcf/d Aker treating facility was completed in 2007 and additional expansions are underway at this facility in 2008;
- Construction of the Weatherford gas processing facility within our North Texas system was completed in September 2007 with a processing capacity of approximately 35 MMcf/d. At the end of 2007, additional processing capacity was added to increase its capacity from 35 MMcf/day to 75/MMcf/day.
- In the second half of 2007 we completed three HCDP plants totaling 550 MMcf/d of capacity within our East Texas system.

The gathering, treating, processing and transportation assets we have placed in service over the past several years on our East Texas system are well positioned to capture the growing supply of natural gas being produced in the region as a result of the improved access to primary natural gas markets provided by our Clarity project.

A substantial portion of natural gas on our North Texas system is produced in the Barnett Shale area within the Fort Worth Basin Conglomerate. The Fort Worth Basin Conglomerate is a mature zone that is experiencing slow production decline. In contrast, the Barnett Shale area is one of the most active natural gas plays in North America. While abundant natural gas reserves have been known to exist in the Barnett Shale area since the early 1980s, technological developments in fracturing the shale formation allows commercial production of these natural gas reserves. Based on the latest information available for 2007, Barnett Shale production has risen from approximately 110 MMcf/d in 1999 to over 2,900 MMcf/d in 2007, with the drilling of over 6,600 wells. We anticipate that throughput on the North Texas system will increase modestly in each of the next several years as a result of Barnett Shale development.

Our Anadarko system is located within the Anadarko basin and continues to experience considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. We have expanded our natural gas processing capacity to approximately 445 MMcf/d at the end of 2007, with the addition of the Hidetown processing facility with 120 MMcf/d of capacity. We also continue to add field compression to accommodate the volume growth on this system.

We intend to expand our natural gas gathering and processing services primarily through internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value for our existing assets.

Our natural gas pipelines generally serve different geographical areas, with differing supply and demand characteristics in each market. We believe demand and competition for natural gas in the areas served by our natural gas assets will generally remain strong as a result of being located in areas where industrial, commercial or residential growth is occurring. The greatest demand for services in the markets served by our natural gas assets occurs in the winter months.

The table below indicates the capacity in MMcf/d of the transportation and wholesale customer pipelines with firm transportation contracts and the amount of capacity that is reserved under those contracts as of that date.

Major System	Capacity MMcf/d	Percentage Reserved Under Contract as of December 31, 2007
UTOS system	1,200	0%
Midla system	200	74%
AlaTenn system	200	28%
Bamagas system	450	61%

Our UTOS system transports natural gas from offshore platforms on a fee for service basis to other pipelines onshore for further delivery and does not have long-term contracts. The average daily throughput on our UTOS system during 2007 was 192,000 MMBtu/d. The FERC approved our negotiated settlement with UTOS shippers, keeping our current rates in effect under our 2003 FERC Order, through 2006. In February 2007, the FERC approved our application for an extension of that Order to keep the settlement rates in effect for an additional 3-year term through 2009.

Our Midla, AlaTenn and Bamagas systems primarily serve industrial corridors and power plants in Louisiana, Alabama and Tennessee. Industries in the area include energy intensive segments of the petrochemical and pulp and paper industries. We market the unused capacity on these systems under both short-term firm and interruptible transportation contracts and long-term firm transportation contracts. These systems are located in areas where opportunities exist to serve new industrial facilities and to make delivery interconnects to alleviate capacity constraints on other third-party pipeline systems. As of December 31, 2007, approximately 74 percent of contracted capacity of the Midla system and approximately 15 percent of the AlaTenn system is under contract to our marketing business. We recently initiated negotiations with a major customer of our Midla mainline transmission system for the renewal of a contract that is set to expire in August 2008. Although the ultimate outcome of these negotiations is uncertain, we may incur a non-cash impairment charge for this asset, if the customer elects not to renew the contract, or renews the contract on less favorable terms. We are also exploring alternative uses for this pipeline system.

The Bamagas system in northern Alabama is contiguous with our AlaTenn system and serves two power plants that are indirectly owned by Calpine Corporation ("Calpine"). In December 2005, Calpine Corporation ("Calpine") and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. Since filing for bankruptcy, Calpine has continued to perform under the terms of its agreements with Bamagas. In June 2007, Calpine and certain of its subsidiaries filed a Joint Plan of Reorganization and Disclosure Statement with the United States Bankruptcy Court. On December 19, 2007, the U.S. Bankruptcy Court for the Southern District of New York issued a decision confirming Calpine's reorganization plan. In addition, the Bamagas contracts with Calpine have been reaffirmed. Calpine announced at the end of January 2008 that it has emerged from Bankruptcy.

Our long-term financial condition depends on the continued availability of natural gas for transportation to the markets served by our systems. Existing customers may not extend their contracts if the availability of natural gas from the Mid-continent and Gulf Coast producing regions was to decline and if the cost of transporting natural gas from other producing regions through other pipelines into the areas we serve were to render the delivered cost of natural gas uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Competition. Competition from other pipeline companies is significant in all the markets we serve. Competitors of our gathering, treating and processing systems include interstate and intrastate pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs. Some of these competitors are substantially larger than we are. Competition for the services we provide varies based upon the location of gathering, treating and processing facilities. Most natural gas producers and owners have alternate gathering, treating and processing facilities available to them. In addition, they have alternatives such as building their own gathering facilities or in some cases, selling their natural gas supplies without treating and processing. In addition to location, competition also varies based upon pricing arrangements and reputation. On the sour gas systems, such as our East Texas system, competition is more limited due to the infrastructure required to treat sour gas.

Competition for customers in the marketing of residue gas is based primarily upon the price of the delivered gas, the services offered by the seller and the reliability of the seller in making deliveries. Residue gas also competes on a price basis with alternative fuels such as crude oil and coal, especially for customers that have the capability of using these alternative fuels, and on the basis of local environmental considerations. Competition in the marketing of NGLs comes from other NGL marketing companies, producers, traders, chemical companies and other asset owners.

Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers we serve have multiple pipelines connected or adjacent to their facilities. Accordingly, many of these customers have the ability to purchase natural gas directly from a number of pipelines or third parties that may hold capacity on the various pipelines. In addition, a number of new interstate natural gas pipelines are being constructed in areas currently served by some of our intrastate and interstate pipelines. When completed, these new pipelines may compete for customers with our existing pipelines.

Trucking and Liquids Marketing Operations

We also include our trucking and liquids marketing operations in our Natural Gas segment. Trucking and liquids marketing operations include the transportation of NGLs, crude oil and carbon dioxide by truck and railcar from wellheads and treating, processing and fractionation facilities and to wholesale customers, such as distributors, refiners and chemical facilities. In addition, our trucking and liquids marketing operations resell these products. A key component of our business is ensuring market access for the liquids extracted at our processing facilities. On average this accounts for approximately 43% of the volume transported by our trucking and liquids marketing business and is a major source of its growth in this area.

Our services are provided using trucks, trailers and rail cars, product treating and handling equipment and NGL storage facilities. In addition, our CO_2 plant, with 250 tons per day of capacity, takes excess CO_2 from hydrogen producers which we then sell to a variety of customers. We also have 50% ownership of an underground propane storage facility in Petal, Mississippi, which augments the services we provide to our customers in the region. The total capacity of this facility is 5.6 million Bbls which increases our storage capabilities.

We have increased the size of our truck fleet by approximately 25 percent since 2005 to meet the growing supply of NGLs, crude oil and carbon dioxide from our processing facilities, as well as to capitalize on the opportunity to better serve our Gulf Coast customers.

Customers. Most of the customers of our trucking and liquids marketing operations are wholesale customers, such as refineries and propane distributors. Our trucking and liquids marketing operations also market products to wholesale customers such as petrochemical plants.

Supply and Demand. The areas served by our trucking and liquids marketing operations are geographically diverse, and the forces that affect the supply of the products transported vary by region. Crude oil and natural gas prices and production levels affect the supply of these products. The demand for services is affected by the demand for NGLs and crude oil by large industrial refineries, and similar customers in the regions served by this business.

Competition. Our trucking and liquids marketing operations have a number of competitors, including other trucking and railcar operations, pipelines, and, to a lesser extent, marine transportation and alternative fuels. In addition, the marketing activities of our trucking and liquids marketing operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Marketing Segment

Our Marketing segment's primary objectives are to mitigate financial risk and maximize the value of the natural gas purchased by our gathering systems and the throughput on our gathering and intrastate wholesale customer pipelines. To achieve this objective, our Marketing segment transacts with various counterparties to provide natural gas supply, transportation, balancing, storage and sales services.

Since our gathering and intrastate wholesale customer pipeline assets are geographically located within Texas, Oklahoma, Alabama, Mississippi and Louisiana, the majority of activities conducted by our Marketing segment are focused within these areas.

Customers. Natural gas purchased by our Marketing segment is sold to industrial, utility and power plant end use customers. In addition, gas is sold to marketing companies at various market hubs. These sales are typically priced based upon a published daily or monthly price index. Sales to end-use customers incorporate a pass-through charge for costs of transportation and additional margin to compensate us for associated services.

Supply and Demand. Supply for our Marketing business depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our Natural Gas segment. Demand is typically driven by weather-related factors with respect to power plant and utility customers, and industrial demand.

Our Marketing business uses third-party storage capacity to balance supply and demand factors within its portfolio. Marketing pays third-party storage facilities and pipelines for the right to store gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities. Due to the increased volumes from our gathering assets, our Marketing business leases third-party pipeline capacity downstream from our Natural Gas assets under firm transportation contracts following specific, controlled guidelines. This capacity is leased for various lengths of time and at rates that allow our Marketing business to diversify its customer base by expanding its service territory. Additionally, this transportation capacity provides assurance that our natural gas will not be shut in, which can result from capacity constraints on downstream pipelines.

Competition. Our Marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and gas producers, independent aggregators and regional marketing companies.

REGULATION

FERC Allowance for Income Taxes in Interstate Common Carrier Pipeline Rates

In a 1995 decision involving our Lakehead system, which we refer to as the *Lakehead ruling*, the FERC partially disallowed the inclusion of income taxes in the cost of service for the Lakehead system. In its *Lakehead ruling*, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. A subsequent appeal of the *Lakehead ruling* was resolved by settlement and therefore was not adjudicated. In another FERC proceeding involving Santa Fe Pacific Pipeline, L.P. (SFPP), an unrelated pipeline entity, the FERC initially relied on its previous *Lakehead ruling* to hold that SFPP could not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. SFPP and other parties to the proceeding appealed the FERC's orders to the United States Court of Appeals for the District of Columbia Circuit, or the D.C. Circuit Court.

In a decision issued in July 2004, in *BP West Coast Products, LLC v. FERC*, which we refer to as the *BP West Coast decision*, the D.C. Circuit Court vacated the portion of the FERC decision regarding the proper tax allowance for SFPP and remanded the case to the FERC for further proceedings.

In May and June 2005, the FERC issued a policy statement, as well as an order on remand of *BP West* Coast (the SFPP order), respectively, in which it stated it will permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be determined by the FERC on a case-by-case basis. The new policy entails rate risk due to the case-by-case review requirement.

In December 2005, the FERC issued its first case-specific review of the income tax allowance issue reaffirming its income tax allowance policy and directing the pipeline to provide certain evidence necessary to determine its income tax allowance. The FERC's *BP West Coast* remand decision and the new tax allowance policy were appealed to the D.C. Circuit Court.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment. The tax effects of significant temporary differences representing deferred tax assets and liabilities are as follows:

Net book basis of assets in excess of tax basis	$ (1.3)
Net book losses on derivatives not recognized for tax purposes	1.9
Net deferred tax asset	$ 0.6

Accounting for Uncertainty in Income Taxes

In July 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement 109,* or FIN 48. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes* . We implemented FIN 48 during the first quarter of 2007. Our adoption of FIN 48 did not materially affect our operating results, financial position or cash flows. As of December 31, 2007, we have no liability reported for unrecognized tax benefits.

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ending December 2006, 2005, and 2004.

16. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following table presents certain financial information relating to our business segments as of and for the years ended December 31, 2007, 2006 and 2005.

	As of and for the Year Ended December 31, 2007				
	Liquids	Natural Gas	Marketing	Corporate [1]	Total
			(in millions)		
Total revenue	$ 548.1	$ 5,807.3	$ 3,527.5	$ —	$ 9,882.9
Less: Intersegment revenue	—	2,363.3	237.0	—	2,600.3
Operating revenue	548.1	3,444.0	3,290.5	—	7,282.6
Cost of natural gas	—	2,990.0	3,256.9	—	6,246.9
Operating and administrative	156.1	266.7	8.0	3.5	434.3
Power	117.0	—	—	—	117.0
Depreciation and amortization	67.9	96.1	1.6	—	165.6
Operating income	207.1	91.2	24.0	(3.5)	318.8
Interest expense	—	—	—	99.8	99.8
Other income	—	—	—	3.0	3.0
Income from continuing operations before income tax expense	207.1	91.2	24.0	(100.3)	222.0
Income tax expense	—	—	—	5.1	5.1
Income from continuing operations	207.1	91.2	24.0	(105.4)	216.9
Income from discontinued operations	—	32.6	—	—	32.6
Net income	$ 207.1	$ 123.8	$ 24.0	$ (105.4)	$ 249.5
Total assets	$ 2,976.9	$ 3,461.1	$ 349.6	$ 104.0	$ 6,891.6
Capital expenditures (excluding acquisitions)	$ 1,218.8	$ 747.9	$ 1.6	$ 11.9	$ 1,980.2

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

	As of and for the Year Ended December 31, 2006				
	Liquids	Natural Gas	Marketing	Corporate [1]	Total
			(in millions)		
Total revenue	$ 512.8	$ 5,404.1	$ 3,182.3	$ —	$ 9,099.2
Less: Intersegment revenue	—	2,383.4	206.8	—	2,590.2
Operating revenue	512.8	3,020.7	2,975.5	—	6,509.0
Cost of natural gas	—	2,601.1	2,913.5	—	5,514.6
Operating and administrative	141.3	215.4	5.4	2.7	364.8
Power	107.6	—	—	—	107.6
Depreciation and amortization	64.1	70.3	0.5	0.2	135.1
Operating income	199.8	133.9	56.1	(2.9)	386.9
Interest expense	—	—	—	110.5	110.5
Other income	—	—	—	8.5	8.5
Income from continuing operations before income taxes	199.8	133.9	56.1	(104.9)	284.9
Income tax expense	—	—	—	—	—

Income from continuing operations		199.8		133.9		56.1		(104.9)		284.9
Income from discontinued operations		—		—		—		—		—
Net income	$	199.8	$	133.9	$	56.1	$	(104.9)	$	284.9
Total assets	$	1,816.4	$	2,797.3	$	366.9	$	243.2	$	5,223.8
Capital expenditures (excluding acquisitions)	$	237.2	$	614.8	$	1.9	$	10.5	$	864.4

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

	As of and for the Year Ended December 31, 2005				
	Liquids	Natural Gas	Marketing	Corporate [(1)]	Total
			(in millions)		
Total revenue	$ 418.0	$ 4,945.1	$ 3,884.2	$ —	$ 9,247.3
Less: Intersegment revenue	—	2,593.0	177.4	—	2,770.4
Operating revenue	418.0	2,352.1	3,706.8	—	6,476.9
Cost of natural gas	—	2,018.7	3,744.6	—	5,763.3
Operating and administrative	144.2	175.0	4.1	3.5	326.8
Power	74.8	—	—	—	74.8
Depreciation and amortization	71.7	66.0	0.5	—	138.2
Gain on sale of assets	—	(18.1)	—	—	(18.1)
Operating income	127.3	110.5	(42.4)	(3.5)	191.9
Interest expense	—	—	—	107.7	107.7
Other income	—	—	—	5.0	5.0
Income from continuing operations before income taxes	127.3	110.5	(42.4)	(106.2)	89.2
Income tax expense	—	—	—	—	—
Income from continuing operations	127.3	110.5			
Income from discontinued operations	—	—	—	—	—
Net income	$ 127.3	$ 110.5	$ (42.4)	$ (106.2)	$ 89.2
Total assets	$ 1,664.0	$ 2,145.9	$ 512.3	$ 106.2	$ 4,428.4
Capital expenditures (excluding acquisitions)	$ 77.0	$ 263.8	$ 0.2	$ 3.8	$ 344.8

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

17. SUBSEQUENT EVENTS

On January 28, 2008, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2008. The distribution was paid to unitholders of record as of February 6, 2008, of our available cash of $96.7 million at December 31, 2007, or $0.950 per limited partner unit. Of this distribution, $66.0 million was paid in cash, $12.9 million was distributed in i-units to our i-unitholder, $17.2 million was distributed in Class C units to the holders of our Class C units and $0.6 million was retained from the General Partner in respect of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

Enterprise Products Partners L.P.
2007 Form 10-K

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ___to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0568219** (I.R.S. Employer Identification No.)
1100 Louisiana, 10 th Floor, Houston, Texas (Address of Principal Executive Offices)	**77002** (Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	New York Stock Exchange

Securities to be registered pursuant to Section 12(g) of the Act : None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of the common units of *Enterprise Products Partners L.P.* ("EPD") held by non-affiliates at June 30, 2007, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange, was approximately $9.1 billion. This figure excludes common units beneficially owned by certain affiliates, including (i) Dan L. Duncan, (ii) Enterprise GP Holdings L.P. and (iii) certain trusts established for the benefit of Mr. Duncan's family. There were 435,297,303 common units of EPD outstanding at February 1, 2008.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.

PART I

Items 1 and 2. *Business and Properties* .

General

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through EPO. Our principal executive offices are located at 1100 Louisiana, 10 th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website is www.epplp.com .

We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We are owned 98% by our limited partners and 2% by our general partner, EPGP. Our general partner is owned by a publicly traded affiliate, Enterprise GP Holdings, the common units of which are listed on the NYSE under the ticker symbol "EPE."

Business Strategy

We operate an integrated network of midstream energy assets that includes: natural gas gathering, treating, processing, transportation and storage; NGL fractionation (or separation), transportation, storage and import and export terminalling; crude oil transportation; offshore production platform services; and petrochemical transportation and services. Our business strategies are to:

- capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains and U.S. Gulf Coast regions, including the Gulf of Mexico;
- capitalize on expected demand growth for natural gas, NGLs, crude oil and refined products;
- maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;
- share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth projects or purchase the project's end products; and
- increase fee-based cash flows by investing in pipelines and other fee-based businesses.

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As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. For information regarding our growth capital projects, see "Capital Spending" included under Item 7 of this annual report.

Financial Information by Business Segment

For information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Recent Developments

For information regarding our recent developments, see "Overview of Business -- Recent Developments" included under Item 7 of this annual report, which is incorporated by reference into this Item 1.

Segment Discussion

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments:

- NGL Pipelines & Services;
- Onshore Natural Gas Pipelines & Services;
- Offshore Pipelines & Services; and
- Petrochemical Services.

Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced, services rendered, seasonality, competition and regulation. Our results of operations and financial condition are subject to a variety of risks. For information regarding our key risk factors, see Item 1A of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "Regulation" and "Environmental and Safety Matters" included within this Item 1.

Our revenues are derived from a wide customer base. During 2007, 2006 and 2005, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9%, 6.1% and 6.8%, respectively, of our consolidated revenues.

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As generally used in the energy industry and in this document, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet

The following discussion of our business segments provides information regarding our principal plants, pipelines and other assets. For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, see Item 7 of this annual report.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 13,758 miles including our 7,808-mile Mid-America Pipeline System, (iii) NGL and related product storage facilities and (iv) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, principally for use in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives, and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing and related NGL marketing activities . At the core of our natural gas processing business are 26 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Natural gas produced at the wellhead especially in association with crude oil contains varying amounts of NGLs. This "rich" natural gas in its raw form is usually not acceptable for transportation in the nation's major natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove the NGLs from the natural gas stream, enabling the natural gas to meet transmission pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemical and motor gasoline production than their value as components of the natural gas stream. After extraction, we typically transport the mixed NGLs to a centralized facility for fractionation (or separation) into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

When operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted from a stream of natural gas, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we earn and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract and generally bears the natural gas cost for shrinkage and plant fuel. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs of which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our margin-band and keepwhole gas processing contracts to compensate the producer for the natural gas equivalent energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, our margin band contracts contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity financial instruments. For information regarding our use of commodity financial instruments, see "Quantitative and Qualitative Disclosures About Market Risks" included under Item 7A of this annual report.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and purchases from third parties on the open market. These sales contracts may also include forward product sales contracts. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

NGL pipelines, storage facilities and import/export terminals. Our NGL pipeline, storage and terminalling operations include approximately 13,758 miles of NGL pipelines, 154.9 million barrels of working capacity for underground NGL and related product storage and two import/export facilities.

Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; distribute and collect NGL products to and from petrochemical plants and refineries; and deliver propane to customers along the Dixie Pipeline and certain sections of the Mid-America Pipeline System. Revenue from our NGL pipeline transportation agreements is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged to our NGL and petrochemical marketing activities, which are eliminated in consolidation). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Typically, we do not take title to the products transported in our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

Our NGL and related product storage facilities are integral parts of our operations. In general, our underground storage wells are used to store our and our customers' mixed NGLs, NGL products and petrochemical products. Under our NGL and related product storage agreements, we charge customers

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monthly storage reservation fees to reserve storage capacity in our underground caverns. The customers pay reservation fees based on the quantity of capacity reserved rather than the actual quantity utilized. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge our customers throughput fees based on volumes injected and withdrawn from the storage facility. Accordingly, the profitability of our storage operations is dependent upon the level of capacity reserved by our customers, the volume of product injected and withdrawn from our underground caverns and the level of fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas. Our import facility is primarily used to offload volumes for delivery to our NGL storage and fractionation facilities near Mont Belvieu, Texas. Our export facility includes an NGL products chiller and related equipment used for loading refrigerated marine tankers for third-party export customers. Revenues from our import and export services are primarily based on fees per unit of volume loaded or unloaded and may also include demand payments. Accordingly, the profitability of our import and export activities primarily depends on the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in eight NGL fractionation facilities located in Texas and Louisiana. NGL fractionation facilities separate mixed NGL streams into purity NGL products. The three primary sources of mixed NGLs fractionated in the United States are (i) domestic natural gas processing plants, (ii) domestic crude oil refineries and (iii) imports of butane and propane mixtures. The mixed NGLs delivered from domestic natural gas processing plants and crude oil refineries to our NGL fractionation facilities are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck.

Extraction of mixed NGLs by natural gas processing plants represents the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast and Rocky Mountain natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities by joint owners and third-party customers.

The majority of our NGL fractionation facilities process mixed NGL streams for third-party customers and support our NGL marketing activities under fee-based arrangements. These fees (typically in cents per gallon) are subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco facility, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). We are exposed to fluctuations in NGL prices to the extent we fractionate volumes for customers under percent-of-liquids arrangements. Our fee-based customers generally retain title to the NGLs that we process for them.

Seasonality. Our natural gas processing and NGL fractionation operations exhibit little to no seasonal variation. Likewise, our NGL pipeline operations have not exhibited a significant degree of seasonality overall. However, propane transportation volumes are generally higher in the October through March timeframe in connection with increased use of propane for heating in the upper Midwest and southeastern United States. Our facilities located in the southern United States may be affected by weather events such as hurricanes and tropical storms originating in the Gulf of Mexico.

We operate our NGL and related product storage facilities based on the needs and requirements of our customers in the NGL, petrochemical, heating and other related industries. We usually experience an increase in the demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn for heating needs. In general, our import volumes peak during the spring and summer months and our export volumes are at their highest levels during the winter months.

In support of our commercial goals, our NGL marketing activities rely on inventories of mixed NGLs and purity NGL products. These inventories are the result of accumulated equity NGL production volumes, imports and other spot and contract purchases. Our inventories of ethane, propane and normal butane are typically higher on a seasonal basis from March through November as each are normally in higher demand and at higher price levels during winter months. Isobutane and natural gasoline inventories are generally stable throughout the year. Our inventory cycle begins in late-February to mid-March (the seasonal low point); builds through September; remains level until early December; before being drawn through winter until the seasonal low is reached again.

Competition . Our natural gas processing business and NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of our competitors has varying levels of financial and personnel resources, and competition generally revolves around price, service and location.

In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate liquids pipelines companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and service.

Our competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies primarily in terms of loading and offloading volumes per hour.

We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Although competition for NGL fractionation services is primarily based on the fractionation fee charged, the ability of an NGL fractionator to receive mixed NGLs, store and distribute NGL products is also an important competitive factor and is a function of the existence of the necessary pipeline and storage infrastructure.

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Properties. The following table summarizes the significant natural gas processing assets of our NGL Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:				
Pioneer (2)	Wyoming	100%	1.35	1.35
Meeker (3)	Colorado	100%	0.75	0.75
Toca	Louisiana	63.9%	0.70	1.10
Chaco	New Mexico	100%	0.65	0.65
North Terrebonne	Louisiana	48.8%	0.63	1.30
Calumet	Louisiana	32.0%	0.51	1.60
Neptune	Louisiana	66%	0.43	0.65
Pascagoula	Mississippi	40%	0.40	1.50
Yscloskey	Louisiana	18.3%	0.34	1.85
Thompsonville	Texas	100%	0.30	0.30
Shoup	Texas	100%	0.29	0.29
Gilmore	Texas	100%	0.26	0.26
Armstrong	Texas	100%	0.25	0.25
Matagorda	Texas	100%	0.25	0.25
Others (11 facilities) (4)	Texas, New Mexico, Louisiana	Various (5)	1.27	3.44
Total processing capacities			8.38	15.54

(1) The approximate net natural gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

(2) We acquired a silica gel natural gas processing facility from TEPPCO in March 2006 and subsequently increased the processing capacity from 0.3 Bcf/d to 0.6 Bcf/d. In addition, we constructed a new cryogenic processing facility having 0.75 Bcf/d of processing capacity, which became operational in February 2008.

(3) In October 2007, we commenced natural gas processing operations at our Meeker facility. Phase II of the Meeker facility, which is under construction and expected to be completed in the third quarter of 2008, will double the natural gas processing capacity to 1.5 Bcf/d at this facility.

(4) Includes our Venice, Blue Water, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin and Carlsbad facilities located in New Mexico; and San Martin, Delmita, Sonora, Shilling and Indian Springs facilities located in Texas. We acquired the Indians Springs facility in January 2005. Our ownership in the Venice plant is through our 13.1% equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").

(5) Our ownership in these facilities ranges from 7.4% to 100%.

At the core of our natural gas processing business are 26 processing plants located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate the Toca, Chaco, North Terrebonne, Calumet, Neptune, Carlsbad, Meeker and Pioneer plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 63%, 56% and 53% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 445 railcars, the majority of which are leased. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the United States and parts of Canada. We have rail loading and unloading facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

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The following table summarizes the significant NGL pipelines and related storage assets of our NGL Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100%	7,808	
Dixie Pipeline	South and Southeastern U.S.	74.2% (1)	1,371	
Seminole Pipeline	Texas	90% (2)	1,342	
EPD South Texas NGL System	Texas	100%	1,039	
Louisiana Pipeline System	Louisiana	Various (3)	612	
Promix NGL Gathering System	Louisiana	50%	364	
DEP South Texas NGL Pipeline System	Texas	100% (4)	286	
Houston Ship Channel	Texas	100%	266	
Lou-Tex NGL	Texas, Louisiana	100%	205	
Others (5 systems) (5)	Various	Various	465	
Total miles			13,758	
NGL and related product storage facilities by state:				
Texas (6)				124.5
Louisiana				15.3
Mississippi				5.7
Others (Arizona, Georgia, Iowa, Kansas, Nebraska, Oklahoma)				9.4
Total capacity (7)				154.9

(1) We hold a 74.2% interest in this system through a majority owned subsidiary, Dixie Pipeline Company ("Dixie").

(2) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company ("Seminole").

(3) Of the 612 total miles for this system, we own 100% of 559 miles and 43.5% of the remaining 53 miles.

(4) Reflects consolidated ownership of this system by EPO (34%) and Duncan Energy Partners (66%).

(5) Includes our Tri-States, Belle Rose, Wilprise, and Chunchula pipelines located in the coastal regions of Alabama, Louisiana, and Mississippi and our Meeker pipeline in Colorado. We completed the Meeker pipeline in 2007, which transports NGLs from our Meeker natural gas processing facility to the Mid-America Pipeline System.

(6) The amount shown for Texas includes 33 underground caverns with an aggregate useable storage capacity of approximately 100 MMBbls that we own jointly with Duncan Energy Partners. These caverns are located in Mont Belvieu, Texas.

(7) The 154.9 MMBbls of total useable storage capacity includes 20.8 MMBbls held under operating leases. The leased facilities are located in Texas, Louisiana and Kansas.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our ownership interest). Total net throughput volumes for these pipelines were 1,583 MBPD, 1,450 MBPD and 1,360 MBPD during the years ended December 31, 2007, 2006 and 2005, respectively.

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of Tri-States and a small portion of the Louisiana Pipeline System.

- The *Mid-America Pipeline System* is a regulated NGL pipeline system consisting of three primary segments: the 2,785-mile Rocky Mountain pipeline, the 2,771-mile Conway North pipeline and the 2,252-mile Conway South pipeline. This system covers thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. During 2007, the Rocky Mountain pipeline's capacity was increased by 50 MBPD. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the

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Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third-party connections. The Conway South pipeline, which completed an expansion in 2007, connects the Conway hub with Kansas refineries and transports NGLs to and from Conway, Kansas to the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionator and storage facility at the Hobbs hub. We also own fifteen unregulated propane terminals that are an integral part of the Mid-America Pipeline System.

During 2007, approximately 51% of the volumes transported on the Mid-America Pipeline System were mixed NGLs originating from natural gas processing plants located in the Permian Basin in west Texas, the Hugoton Basin of southwestern Kansas, the San Juan Basin of northwest New Mexico, the Piceance Basin of Colorado, the Uintah Basin of Colorado and Utah and the Greater Green River Basin of southwestern Wyoming. The remaining volumes are generally purity NGL products originating from NGL fractionators in the mid-continent areas of Kansas, Oklahoma, and Texas, as well as deliveries from Canada.

- The *Dixie Pipeline* is a regulated propane pipeline extending from southeast Texas and Louisiana to markets in the southeastern United States. Propane supplies transported on this system primarily originate from southeast Texas, southern Louisiana and Mississippi. This system operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina.

- The *Seminole Pipeline* is a regulated pipeline that transports NGLs from the Hobbs hub and the Permian Basin area of west Texas to markets in southeastern Texas. NGLs originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

- The *EPD South Texas NGL System* is a network of NGL gathering and transportation pipelines located in south Texas. The system includes 379 miles of pipeline used to gather and transport mixed NGLs from our south Texas natural gas processing facilities to our south Texas NGL fractionation facilities. The pipeline system also includes approximately 660 miles of pipelines that deliver NGLs from our south Texas fractionation facilities to refineries and petrochemical plants located between Corpus Christi and Houston, Texas and within the Texas City-Houston area, as well as to common carrier NGL pipelines.

- The *Louisiana Pipeline System* is a network of NGL pipelines located in Louisiana. This system transports NGLs originating in southern Louisiana and Texas to refineries and petrochemical companies along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other facilities located in Louisiana.

- The *Promix NGL Gathering System* is a NGL pipeline system that gathers mixed NGLs from natural gas processing plants in Louisiana for delivery to an NGL fractionator owned by K/D/S Promix, L.L.C. ("Promix"). This gathering system is an integral part of the Promix NGL fractionation facility. Our ownership interest in this pipeline is held indirectly through our equity method investment in Promix.

- The *DEP South Texas NGL Pipeline System* transports NGLs from our Shoup and Armstrong fractionation facilities in south Texas to Mont Belvieu, Texas. This system became operational in January 2007.

  We contributed a direct 66% equity interest in South Texas NGL Pipelines, LLC ("South Texas NGL"), our subsidiary that owns the DEP South Texas NGL Pipeline System, to Duncan Energy Partners effective February 1, 2007. We own the remaining 34% direct equity interest in South Texas NGL. For additional information regarding Duncan Energy Partners, see "Other Items – Initial Public Offering of Duncan Energy Partners" included under Item 7 of this annual report.

- The *Houston Ship Channel* pipeline system is a collection of pipelines extending from our Houston Ship Channel import/export facility and Morgan's Point facility to Mont Belvieu, Texas.

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This system is used to deliver NGL products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities.

- The *Lou-Tex NGL* pipeline system is used to provide transportation services for NGLs and refinery grade propylene between the Louisiana and Texas markets. We also use this pipeline to transport mixed NGLs from certain of our Louisiana gas processing plants to our Mont Belvieu NGL fractionation facility.

Our NGL and related product storage facilities are integral parts of our pipeline and other operations. In general, these underground storage facilities are used to store NGLs and petrochemical products for us and our customers. Our underground storage facilities include locations in Arizona and Kansas that were acquired in July 2005. We operate these facilities, with the exception of certain storage locations operated for us by a third party in Louisiana.

We contributed a direct 66% equity interest in our subsidiary, Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"), to Duncan Energy Partners on February 5, 2007. We own the remaining 34% direct equity interest in Mont Belvieu Caverns. Mont Belvieu Caverns owns 33 underground storage caverns with an aggregate underground storage capacity of approximately 100 MMBbls, and a brine system with approximately 20 MMBbls of above-ground storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast. In 2007, we modified certain wells at our Mont Belvieu Caverns' facility to enable us to also store refined products such as motor gasoline and diesel fuel. For information regarding our ongoing Mont Belvieu storage well optimization projects, see "Liquidity and Capital Resources – Capital Spending" included under Item 7 of this annual report.

The following table summarizes the significant NGL fractionation assets of our NGL Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu	Texas	75%	178	230
Shoup and Armstrong	Texas	100%	87	87
Hobbs	Texas	100%	75	75
Norco	Louisiana	100%	75	75
Promix	Louisiana	50%	73	145
BRF	Louisiana	32.2%	19	60
Tebone	Louisiana	43.5%	12	30
Total plant capacities			519	702

(1) The approximate net NGL fractionation capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities.

- Our *Mont Belvieu* NGL fractionation facility is located at Mont Belvieu, Texas, which is a key hub of the domestic and international NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountain Overthrust, East Texas and the Gulf Coast.

- Our *Shoup* and *Armstrong* NGL fractionation facilities fractionate mixed NGLs supplied by our south Texas natural gas processing plants. The Shoup and Armstrong facilities supply NGLs transported by the DEP South Texas NGL Pipeline System.

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- The *Hobbs* NGL fractionation facility is located in Gaines County, Texas, where it serves petrochemical end users and refineries in West Texas, New Mexico and California. In addition, the Hobbs facility can supply exports to northern Mexico through existing pipeline infrastructure. The Hobbs facility receives mixed NGLs from several major supply basins including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountain Overthrust. The facility is strategically located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, providing us flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.
- The *Norco* NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Yscloskey, Pascagoula, Venice and Toca facilities.
- The *Promix* NGL fractionation facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including our Calumet, Neptune, Burns Point and Pascagoula facilities. In addition to the 364-mile Promix NGL Gathering System, Promix owns five NGL storage caverns and a barge loading facility that is integral to its operations.
- The *BRF* facility fractionates mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 80%, 75% and 74% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such facilities. We own direct consolidated interests in all of our NGL fractionation facilities with the exception of a 50% interest in a facility owned by Promix and a 32.2% interest in a facility owned by Baton Rouge Fractionators LLC ("BRF").

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP ("OTTI"). In June 2007, we completed an expansion of our OTTI facilities, which significantly increased our loading and offloading capabilities. Our OTTI import facility can now offload NGLs from tanker vessels at rates up to 20,000 barrels per hour depending on the product. Our OTTI export facility can now load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. Previously, our offloading rate was up to 10,000 barrels per hour (depending on product) and our maximum loading rate was 5,000 barrels per hour. In addition to our OTTI facilities, we own a barge dock that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. Our average combined NGL import and export volumes were 84 MBPD, 127 MBPD and 119 MBPD for 2007, 2006 and 2005, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 17,758 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Onshore natural gas pipelines and related natural gas marketing. Our onshore natural gas pipeline systems provide for the gathering and transmission of natural gas from onshore developments, such as the San Juan, Barnett Shale, Permian, Piceance and Greater Green River supply basins in the Western U.S., and from offshore developments in the Gulf of Mexico through connections with offshore pipelines. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers or to other onshore pipelines.

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Certain of our onshore natural gas pipelines generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Intrastate natural gas pipelines (such as our Acadian Gas and Alabama Intrastate systems) may also purchase natural gas from producers and suppliers and resell such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers.

We entered the natural gas marketing business in 2001 when we acquired the Acadian Gas System. In 2007, we initiated an expansion of this marketing business to leverage off our other natural gas pipeline assets. Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained primarily from (i) third party well-head purchases, (ii) our natural gas processing plants or (iii) the open market. In general, our natural gas sales contracts utilize market-based pricing and can incorporate pricing differentials for factors such as delivery location. We expect our natural gas marketing business to continue to grow in the future. Our consolidated revenues from this business were $1.6 billion, $1.2 billion and $1.1 billion for the years ended December 31, 2007, 2006 and 2005, respectively.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes through our natural gas marketing activities or through certain contracts on our intrastate natural gas pipelines. In addition, our San Juan, Waha, Carlsbad and Jonah pipelines provide aggregating and bundling services, in which we purchase and resell natural gas for certain small producers. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to commodity prices through transportation arrangements with shippers. For example, approximately 95% of the fee-based gathering arrangements of our San Juan Gathering System are calculated using a percentage of a regional price index for natural gas. We use commodity financial instruments from time to time to mitigate our exposure to risks related to commodity prices. For information regarding our use of commodity financial instruments, see "Quantitative and Qualitative Disclosures About Market Risks" included under Item 7A of this annual report.

Underground natural gas storage . We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that are ideally situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. On a combined basis, these facilities (our Petal Gas Storage ("Petal") and Hattiesburg Gas Storage ("Hattiesburg") locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

The ability of salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities. Our salt dome storage facilities permit sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal.

Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage, and (ii) storage fees per unit of volume stored at our facilities.

Seasonality . Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation facilities increase output to meet residential and commercial demand for electricity for air conditioning and in the winter months natural gas is needed as fuel for residential and commercial heating. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities.

Competition . Within their market areas, our onshore natural gas pipelines compete with other onshore natural gas pipelines on the basis of price (in terms of transportation fees and/or natural gas selling

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prices), service and flexibility. Our competitive position within the onshore market is enhanced by our longstanding relationships with customers and the limited number of delivery pipelines connected (or capable of being economically connected) to the customers we serve.

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. We believe that the locations of our natural gas storage facilities allow us to compete effectively with other companies who provide natural gas storage services.

Properties. The following table summarizes the significant assets of our Onshore Natural Gas Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:					
Texas Intrastate System	Texas	100% (1)	6,976	5,155	
Piceance Creek Gathering System	Colorado	100%	48	1,600	
San Juan Gathering System	New Mexico, Colorado	100%	6,065	1,200	
Acadian Gas System	Louisiana	Various (2)	1,042	1,149	
Jonah Gathering System	Wyoming	19.4%	643	387	
Waha Gathering System	Texas, New Mexico	100%	465	380	
Carlsbad Gathering System	Texas, New Mexico	100%	919	220	
Alabama Intrastate System	Alabama	100%	408	200	
Encinal Gathering System	Texas	100%	449	143	
Other (6 systems) (3)	Texas, Mississippi	Various (4)	743		
Total miles			17,758		
Natural gas storage facilities:					
Petal	Mississippi	100%			14.1
Hattiesburg	Mississippi	100%			4.0
Wilson	Texas	Leased (5)			6.4
Acadian	Louisiana	Leased (6)			3.0
Total gross capacity					27.5

(1) We own a 50% undivided interest in the 641-mile Channel pipeline system, which is a component of the Texas Intrastate System. The remaining 50% is owned by affiliates of Energy Transfer Equity. In addition, we own less than a 100% undivided interest in certain segments of the Enterprise Texas pipeline system.

(2) Reflects consolidated ownership of Acadian Gas by EPO (34%) and Duncan Energy Partners (66%). Also includes the 49.5% equity investment that Acadian Gas has in the Evangeline pipeline.

(3) Includes the Delmita, Big Thicket, Indian Springs and Canales gathering systems located in Texas and the Petal and Hattiesburg pipelines located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. We acquired the Canales gathering system in connection with the Encinal acquisition in July 2006. The Petal and Hattiesburg pipelines are integral components of our natural gas storage operations.

(4) We own 100% of these assets with the exception of the Indian Springs system, in which we own an 80% undivided interest through a consolidated subsidiary.

(5) This facility is held under an operating lease that expires in January 2028.

(6) We hold this facility under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 64%, 71% and 73% during the years ended December 31, 2007, 2006 and 2005, respectively. The utilization rate for 2007 excludes our Piceance Creek Gathering System, which operated at an average utilization rate of 24% during 2007 as volumes ramped-up on this system. Our utilization rates reflect the periods in which we owned an interest in such assets, or, for recently constructed assets, since the dates such assets were placed into service.

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The following information highlights the general use of each of our principal onshore natural gas pipelines and storage facilities, all of which we operate.

- The *Texas Intrastate System* gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. This system serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area, the Houston area, and the Houston Ship Channel industrial market. The Texas Intrastate System is comprised of the 6,106-mile Enterprise Texas pipeline system, the 229-mile TPC Offshore gathering system and the 641-mile Channel pipeline system. The leased Wilson natural gas storage facility is an integral part of the Texas Intrastate System.

  In November 2006, we announced an expansion of our Texas Intrastate System with the construction of the Sherman Extension that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. For information regarding this expansion projects, see "Liquidity and Capital Resources — Capital Spending" included under Item 7 of this annual report.

- The *Piceance Creek Gathering System* consists of a recently constructed natural gas gathering pipeline located in the Piceance Basin of northwestern Colorado. We acquired this pipeline from EnCana Oil & Gas ("EnCana") in December 2006. The Piceance Creek Gathering System extends from a connection with EnCana's Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.5 Bcf/d Meeker natural gas treating and processing complex, which completed its first phase of construction in October 2007. We placed the Piceance Creek Gathering System into service in January 2007 and it currently transports approximately 520 MMcf/d of natural gas. With connectivity to EnCana's Great Divide Gathering System, our Piceance Creek Gathering System has access to natural gas production from the southern portion of the Piceance basin, including production from EnCana's Mamm Creek field.

- The *San Juan Gathering System* serves natural gas producers in the San Juan Basin of New Mexico and Colorado. This system gathers natural gas production from over 10,630 producing wells in the San Juan Basin and delivers the natural gas to natural gas processing facilities, including our Chaco facility.

  In November 2007, we and the Jicarilla Apache Nation announced the formation of a joint venture to own and operate natural gas gathering assets located on or near Jicarilla Apache Nation reservation lands. For additional information regarding this new joint venture, see "Recent Developments" included under Item 7 of this annual report.

- The *Acadian Gas System* purchases, transports, stores and sells natural gas in Louisiana. The Acadian Gas System is comprised of the 577-mile Cypress pipeline, 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The leased Acadian natural gas storage facility is an integral part of the Acadian Gas System.

  We contributed a direct 66% equity interest in Acadian Gas, LLC ("Acadian Gas"), which is a subsidiary that owns the Cypress and Acadian pipelines, to Duncan Energy Partners on February 5, 2007. We own the remaining 34% direct equity interest in Acadian Gas. For additional information regarding Duncan Energy Partners, see "Other Items — Initial Public Offering of Duncan Energy Partners" included under Item 7 of this annual report. Acadian Gas owns a 49.5% indirect interest in the Evangeline pipeline.

- The *Jonah Gathering System* is located in the Greater Green River Basin of southwestern Wyoming. This system gathers natural gas from the Jonah and Pinedale fields for delivery to regional natural gas processing plants, including our Pioneer facility, and major interstate pipelines. Our ownership in this gathering system is through our 19.4% equity method investment in Jonah Gas Gathering Company, which we acquired from TEPPCO in August 2006. We completed the first portion of the Phase V expansion the Jonah Gathering System in July 2007.

Currently the gross gathering capacity of this system is 2.0 Bcf/d (net to our interest, 387 MMcf/d) and is expected to increase to 2.4 Bcf/d upon the completion of the final stage of this expansion in April 2008. For additional information regarding this joint venture arrangement with TEPPCO, see Item 13 of this annual report.

- The *Waha and Carlsbad Gathering Systems* (formerly our Permian Basin System) gather natural gas from wells in the Permian Basin region of Texas and New Mexico and deliver natural gas into the El Paso Natural Gas, Transwestern and Oasis pipelines.
- The *Alabama Intrastate System* mainly gathers coal bed methane from wells in the Black Warrior Basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.
- The *Encinal Gathering System* gathers natural gas from the Olmos and Wilcox formations in south Texas and delivers into our Texas Intrastate System, which delivers the natural gas into our south Texas facilities for processing. We acquired this gathering system in connection with the Encinal acquisition in July 2006.
- Our *Petal* and *Hattiesburg* underground storage facilities are strategically situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets and are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems.

We are developing a new natural gas storage cavern located at our Petal facility. The new cavern is designed to store approximately 7.9 Bcf of natural gas, of which approximately 5.0 Bcf will be working gas capacity and 2.9 Bcf will be the base gas requirements needed to support minimum pressures. This expansion project was approved by the FERC and is projected to commence operations during the second quarter of 2008. We have long-term, binding precedent agreements on the majority of the new capacity.

We are developing additional natural gas storage capacity at our Wilson facility. In addition, we are constructing various natural gas gathering pipelines and related assets in the Rocky Mountains region in support of long-term service agreements with major producers. For information regarding these expansion projects, see "Liquidity and Capital Resources — Capital Spending" included under Item 7 of this annual report.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment includes (i) approximately 1,555 miles of offshore natural gas pipelines strategically located to serve production areas including some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 914 miles of offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities.

Offshore natural gas pipelines . Our offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from production developments located in the Gulf of Mexico, primarily offshore Louisiana and Texas. Typically, these systems receive natural gas from producers, other pipelines and shippers through system interconnects and transport the natural gas to various downstream pipelines, including major interstate transmission pipelines that access multiple markets in the eastern half of the United States.

Our revenues from offshore natural gas pipelines are derived from fee-based agreements and are typically based on transportation fees per unit of volume transported (generally in MMBtus) multiplied by the volume delivered. These transportation agreements tend to be long-term in nature, often involving life-of-reserve commitments with firm and interruptible components. We do not take title to the natural gas volumes that are transported on our natural gas pipeline systems; rather, the shipper retains title and the associated commodity price risk.

Offshore oil pipelines. We own interests in several offshore oil pipeline systems, which are located in the vicinity of oil-producing areas in the Gulf of Mexico. Typically, these systems receive crude oil from offshore production developments, other pipelines or shippers through system interconnects and deliver the oil to either onshore locations or to other offshore interconnecting pipelines.

The majority of revenues from our offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points along our crude oil pipelines for an index-based price (less a price differential) and sell the oil back to the shippers at various redelivery points at the same index-based price. Net revenue recognized from such arrangements is based on a price differential per unit of volume (typically in barrels) multiplied by the volume delivered. In addition, certain of our offshore crude oil pipelines generate revenues based upon a transportation fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to (i) production from reserves committed under long-term contracts for the productive life of the relevant field or (ii) contracts for the purchase and sale of crude oil with terms from two to twelve months. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the amount and term of the reserve commitment by the customer.

Offshore platforms. We have ownership interests in six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities. Offshore platforms are critical components of the offshore infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to: (i) interconnect with the offshore pipeline grid; (ii) provide an efficient means to perform pipeline maintenance; (iii) locate compression, separation, production handling and other facilities; (iv) conduct drilling operations during the initial development phase of an oil and natural gas property; and (v) process off-lease production.

Revenues from offshore platform services generally consist of demand payments and commodity charges. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn $55.2 million of demand revenues annually through March 2012. The Marco Polo platform will earn $25.2 million of demand revenues annually through April 2009.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Competition. Within their market area, our offshore natural gas and oil pipelines compete with other pipelines (both regulated and unregulated systems) primarily on the basis of price (in terms of transportation fees), available capacity and connections to downstream markets. To a limited extent, our competition includes other offshore pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. We compete with other platform service providers on the basis of proximity and access to existing reserves and pipeline systems, as well as costs and rates. Furthermore, our competitors may possess greater capital resources than we have available, which could enable them to address business opportunities more quickly than us.

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Properties. The following table summarizes the significant assets of our Offshore Pipelines & Services business segment at February 1, 2008, all of which are located in the Gulf of Mexico primarily offshore Louisiana and Texas.

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Crude Oil (MPBD)
Offshore natural gas pipelines:					
High Island Offshore System	100%	291		1,800	
Viosca Knoll Gathering System	100%	172		1,000	
Independence Trail (1)	100%	134		1,000	
Green Canyon Laterals	Various (2)	95		599	
Anaconda Gathering System (3)	100%	137		550	
Phoenix Gathering System	100%	77		450	
Falcon Natural Gas Pipeline	100%	14		400	
Manta Ray Offshore Gathering System	25.7%	250		206	
Nautilus System	25.7%	101		154	
VESCO Gathering System	13.1%	260		105	
Nemo Gathering System	33.9%	24		102	
Total miles		1,555			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline	50%	374			250
Poseidon Oil Pipeline System	36%	372			144
Allegheny Oil Pipeline	100%	43			140
Marco Polo Oil Pipeline	100%	37			120
Constitution Oil Pipeline	100%	67			80
Typhoon Oil Pipeline	100%	17			80
Tarantula Oil Pipeline	100%	4			30
Total miles		914			
Offshore platforms:					
Independence Hub (1)	80%		8,000	800	NA
Marco Polo	50%		4,300	150	60
Viosca Knoll 817	100%		671	145	5
Garden Banks 72	50%		518	40	18
East Cameron 373	100%		441	195	3
Falcon Nest	100%		389	400	3

(1) In July 2007, the Independence Hub platform and Independence Trail pipeline received first production from deepwater production wells connected to the Independence Hub platform. The Independence Hub platform began earning demand revenues in March 2007.

(2) Our ownership interests in the Green Canyon Laterals ranges from 0% to 100%.

(3) Data shown for the Anaconda Gathering System includes the 30-mile Constitution natural gas pipeline, which we constructed and placed into service in 2006. The Constitution natural gas pipeline has a net capacity of approximately 200 MMcf/d.

We operate our offshore natural gas pipelines, with the exception of the VESCO Gathering System, Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 24%, 26% and 30% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such assets.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines.

- The *High Island Offshore System* ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system, Tennessee Gas Pipeline and the U-T Offshore System. The HIOS pipeline system includes eight pipeline junction and service platforms. This system also includes the 86-mile East Breaks System that connects the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25 to the HIOS pipeline system.

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- The *Viosca Knoll Gathering System* transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas to several major interstate pipelines, including the Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.
- The *Independence Trail* natural gas pipeline transports natural gas from our Independence Hub platform to the Tennessee Gas Pipeline. Natural gas transported on the Independence Trail comes from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. This pipeline includes one pipeline junction platform at West Delta 68. We completed construction of the Independence Trail natural gas pipeline during 2006. In July 2007, the Independence Trail pipeline received first production from deepwater wells connected to the Independence Hub platform.
- The *Green Canyon Laterals* consist of 20 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including the HIOS.
- The *Anaconda Gathering System* connects our Marco Polo platform and the third-party owned Constitution platform to the ANR pipeline system. The Anaconda Gathering System includes our wholly-owned Typhoon, Marco Polo and Constitution natural gas pipelines. The Constitution natural gas pipeline serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico.
- The *Phoenix Gathering System* connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.
- The *Falcon Natural Gas Pipeline* delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located on the Brazos Addition Block 133 platform.
- The *Manta Ray Offshore Gathering System* transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System. Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune").
- The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant on the Louisiana gulf coast. Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune.
- The *VESCO Gathering System* is a 260-mile regulated natural gas pipeline system associated with the Venice natural gas processing plant in Louisiana. This pipeline is an integral part of the natural gas processing operations of VESCO. Our 13.1% interest in this system is held through our equity method investment in VESCO.
- The *Nemo Gathering System* transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System. Our ownership interest in this pipeline is held indirectly through our equity method investment in Nemo Gathering Company, LLC.

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The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 19%, 18% and 17% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such assets.

- The *Cameron Highway Oil Pipeline* gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. This pipeline includes one pipeline junction platform. Our 50% joint control ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
- The *Poseidon Oil Pipeline System* gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana. This system includes one pipeline junction platform. Our ownership interest in this pipeline is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC.
- The *Allegheny Oil Pipeline* connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.
- The *Marco Polo Oil Pipeline* transports crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.
- The *Constitution Oil Pipeline* serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. For information regarding this project, see "Liquidity and Capital Resources — Capital Spending" included under Item 7 of this annual report.

The following information highlights the general use of each of our principal Gulf of Mexico offshore platforms. We operate these offshore platforms with the exception of the Marco Polo platform, Independence Hub platform and East Cameron 373.

On a weighted-average basis, utilization rates with respect to natural gas processing capacity of our offshore platforms were approximately 29%, 17% and 27% during the years ended December 31, 2007, 2006 and 2005, respectively. Likewise, utilization rates for our offshore platforms were approximately 26%, 19% and 9%, respectively, in connection with platform crude oil processing capacity. These rates reflect the periods in which we owned an interest in such assets. In addition to the offshore platforms we identified in the preceding table, we own or have an ownership interest in fourteen pipeline junction and service platforms. Our pipeline junction and service platforms do not have processing capacity.

- The *Independence Hub* platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. We successfully installed the Independence Hub platform and began earning demand revenues in March 2007. In July 2007, the Independence Hub platform received first production from deepwater wells connected to the platform. Currently, the platform is receiving approximately 900 MMcf/d of natural gas from fifteen wells.
- The *Marco Polo* platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2, K2 North and Genghis Khan fields. These fields are located

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in the South Green Canyon area of the Gulf of Mexico. Our 50% joint control ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C.

- The *Viosca Knoll 817* platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.
- The *Garden Banks 72* platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.
- The *East Cameron 373* platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.
- The *Falcon Nest* platform, which is located in the Mustang Island Block 103 area of the Gulf of Mexico, currently processes natural gas from the Falcon field.

Petrochemical Services

Our Petrochemical Services business segment includes five propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes approximately 683 miles of petrochemical pipeline systems.

Propylene fractionation. Our propylene fractionation business consists primarily of five propylene fractionation facilities located in Texas and Louisiana, and approximately 613 miles of various propylene pipeline systems. These operations also include an export facility located on the Houston Ship Channel and our petrochemical marketing activities.

In general, propylene fractionation plants separate refinery grade propylene (a mixture of propane and propylene) into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade propylene can also be produced from chemical grade propylene feedstock. Chemical grade propylene is also a by-product of olefin (ethylene) production. The demand for polymer grade propylene is attributable to the manufacture of polypropylene, which has a variety of end uses, including packaging film, fiber for carpets and upholstery and molded plastic parts for appliance, automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations. Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our processing activities and purchases from third parties on the open market. In general, we sell our petrochemical products at market-related prices, which may include pricing differentials for such factors as delivery location.

As part of our petrochemical marketing activities, we have several long-term polymer grade propylene sales agreements. To meet our petrochemical marketing obligations, we have entered into several agreements to purchase refinery grade propylene. To limit the exposure of our petrochemical marketing activities to price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Isomerization. Our isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial

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isomerization complex in the United States. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. The primary uses of isobutane are currently for the production of propylene oxide, isooctane and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. Our isomerization facility provides processing services to meet the needs of third-party customers and our other businesses, including our NGL marketing activities and octane additive production facility.

Octane enhancement . We own and operate an octane additive production facility located in Mont Belvieu, Texas designed to produce isooctane, which is an additive used in reformulated motor gasoline blends to increase octane, and isobutylene. The facility produces isooctane and isobutylene using feedstocks of high-purity isobutane, which is supplied using production from our isomerization units. Prior to mid-2005, the facility produced methyl tertiary butyl ether ("MTBE"). We modified the facility to produce isooctane and isobutylene. Depending on the outcome of various factors, the facility may be further modified in the future to produce alkylate, another motor gasoline additive.

Seasonality . Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher demand in the spring and summer months due to the demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, isooctane prices have been stronger during the April to September period of each year, which corresponds with the summer driving season.

Competition . We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies on the Gulf Coast. Generally, the propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, service, logistics and location.

In the isomerization market, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage infrastructure. We also compete with other octane additive manufacturing companies primarily on the basis of price.

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Properties. The following table summarizes the significant assets of our Petrochemical Services segment at February 1, 2008, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (4 plants)	Texas	Various (1)	73	87	
BRPC	Louisiana	30% (2)	7	23	
Total capacity			80	110	
Isomerization facility:					
Mont Belvieu (3)	Texas	100%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100% (4)			284
Texas City RGP Gathering System	Texas	100%			105
Lake Charles	Texas, Louisiana	50%			83
Others (6 systems) (5)	Texas	Various (6)			211
Total miles					683
Octane additive production facilities:					
Mont Belvieu	Texas	100%	12	12	

(1) We own a 54.6% interest and lease the remaining 45.4% of a facility having 17 MBPD of plant capacity. We own a 66.7% interest in a second facility having 41 MBPD of total plant capacity. We own 100% of the remaining two facilities, which have 14 MBPD and 15 MBPD of plant capacity, respectively.

(2) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").

(3) On a weighted-average basis, utilization rates for this facility were approximately 78%, 70% and 70% during 2007, 2006 and 2005, respectively.

(4) Reflects consolidated ownership of these pipelines by EPO (34%) and Duncan Energy Partners (66%).

(5) Includes our Texas City PGP Delivery System and Port Neches, Bay Area, La Porte, Port Arthur and Bayport petrochemical pipelines.

(6) We own 100% of these pipelines with the exception of the 17-mile La Porte pipeline, in which we hold an aggregate 50% indirect interest through our equity method investments in La Porte Pipeline Company L.P. and La Porte Pipeline GP, L.L.C.

We produce polymer grade propylene at our Mont Belvieu location and chemical grade propylene at our BRPC facility. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of ExxonMobil Corporation into chemical grade propylene. The production of polymer grade propylene from our Mont Belvieu plants is primarily used in our petrochemical marketing activities. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 86%, 86% and 83% during the years ended December 31, 2007, 2006 and 2005, respectively. This business segment also includes an above-ground polymer grade propylene storage and export facility located in Seabrook, Texas. This facility can load vessels at rates up to 5,000 barrels per hour.

The Lou-Tex propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana. We own these pipelines through our subsidiaries, Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene") and Sabine Propylene Pipeline L.P. ("Sabine Propylene"). On February 5, 2007, we contributed a direct 66% equity interest in our subsidiaries that own the Lou-Tex Propylene and Sabine Propylene pipelines to Duncan Energy Partners. We own the remaining 34% direct interest in these subsidiaries. For additional information regarding Duncan Energy Partners, see "Other Items - Initial Public Offering of Duncan Energy Partners" included under Item 7 of this annual report.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance

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with our ownership interest). Total net throughput volumes for these pipelines were 105 MBPD, 97 MBPD and 64 MBPD during the years ended December 31, 2007, 2006 and 2005, respectively.

Our octane additive facility currently has an isooctane production capacity of 12 MBPD. The facility was capable of producing only MTBE prior to mid-2005 at a rate up to 15.5 MBPD. On a weighted-average combined product basis, utilization rates for this facility were approximately 58%, 58% and 29% during the years ended December 31, 2007, 2006 and 2005, respectively.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionator is constructed) and (ii) parcels in which our interests and those of our unconsolidated affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our unconsolidated affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Capital Spending

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from such areas as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, the Barnett Shale in North Texas, and the deepwater Gulf of Mexico. For a discussion of our capital spending program, see "Capital Spending" included under Item 7 of this annual report.

Regulation

Interstate Regulation

Liquids Pipelines . Certain of our crude oil and NGL pipeline systems (collectively referred to as "liquids pipelines") are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to investigate such rates and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it may require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deemed liquids pipeline rates that were in effect for the twelve months preceding enactment and that had not been subject to complaint, protest or investigation, just and reasonable under the Energy Policy Act (i.e., "grandfathered"). Some, but not all, our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our

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Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

- 2% of quarterly cash distributions up to $0.253 per unit;
- 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and
- 25% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $107.4 million, $86.7 million and $63.9 million to EPGP during the years ended December 31, 2007, 2006 and 2005, respectively.

The following table presents our declared quarterly cash distribution rates per unit since the first quarter of 2006 and the related record and distribution payment dates. The quarterly cash distribution rates per unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	Distribution per Unit	Record Date	Payment Date
2006			
1st Quarter	$0.4450	Apr. 28, 2006	May 10, 2006
2nd Quarter	$0.4525	Jul. 31, 2006	Aug. 10, 2006
3rd Quarter	$0.4600	Oct. 31, 2006	Nov. 8, 2006
4th Quarter	$0.4675	Jan. 31, 2007	Feb. 8, 2007
2007			
1st Quarter	$0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter	$0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter	$0.4900	Oct. 31, 2007	Nov. 8, 2007
4th Quarter	$0.5000	Jan. 31, 2008	Feb. 7, 2008

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income at the dates indicated:

	At December 31, 2007	At December 31, 2006
Commodity financial instruments (1)	$(21,619)	$(3,622)
Interest rate financial instruments (1)	34,980	26,034
Foreign currency hedges (1)	1,308	—
Foreign currency translation adjustment (1)	1,200	(807)
Pension and postretirement benefit plans (2)	588	(464)
Total accumulated other comprehensive income	$ 16,457	$21,141

(1) See Note 2 for additional information regarding these components of accumulated other comprehensive income.

(2) See Note 6 for additional information regarding pension and postretirement benefit plans.

Note 16. Business Segments

We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of change in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, substantially all of our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico and Wyoming. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations.

The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

		For the Year Ended December 31, 2007	2006	2005
Revenues (1)		$ 16,950,125	$ 13,990,969	$ 12,256,959
Less:	Operating costs and expenses (1)	(16,009,051)	(13,089,091)	(11,546,225)
Add:	Equity in income of unconsolidated affiliates (1)	29,658	21,565	14,548
	Depreciation, amortization and accretion in operating costs and expenses (2)	513,840	440,256	413,441
	Operating lease expenses paid by EPCO (2)	2,105	2,109	2,112
	Loss (gain) on sale of assets in operating costs and expenses (2)	5,391	(3,359)	(4,488)
Total segment gross operating margin		$ 1,492,068	$ 1,362,449	$ 1,136,347

(1) These amounts are taken from our Statements of Consolidated Operations.

(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows:

	For the Year Ended December 31, 2007	2006	2005
Total segment gross operating margin	$1,492,068	$1,362,449	$1,136,347
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(513,840)	(440,256)	(413,441)
Operating lease expense paid by EPCO	(2,105)	(2,109)	(2,112)
Gain (loss) on sale of assets in operating costs and expenses	(5,391)	3,359	4,488
General and administrative costs	(87,695)	(63,391)	(62,266)
Consolidated operating income	883,037	860,052	663,016
Other expense, net	(303,463)	(229,967)	(225,178)
Income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 579,574	$ 630,085	$ 437,838

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Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments					
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:						
Year ended December 31, 2007	$12,101,715	$1,788,219	$ 222,642	$2,184,833	$ —	$16,297,409
Year ended December 31, 2006	10,079,534	1,407,872	144,065	1,956,268	—	13,587,739
Year ended December 31, 2005	9,006,730	1,185,577	110,100	1,587,037	—	11,889,444
Revenues from related parties:						
Year ended December 31, 2007	369,654	281,876	1,169	17	—	652,716
Year ended December 31, 2006	110,409	291,023	1,798	—	—	403,230
Year ended December 31, 2005	16,689	350,025	696	105	—	367,515
Intersegment and intrasegment revenues:						
Year ended December 31, 2007	5,346,571	191,741	1,959	514,852	(6,055,123)	—
Year ended December 31, 2006	4,131,776	113,132	1,679	383,754	(4,630,341)	—
Year ended December 31, 2005	3,334,763	41,576	1,353	346,458	(3,724,150)	—
Total revenues:						
Year ended December 31, 2007	17,817,940	2,261,836	225,770	2,699,702	(6,055,123)	16,950,125
Year ended December 31, 2006	14,321,719	1,812,027	147,542	2,340,022	(4,630,341)	13,990,969
Year ended December 31, 2005	12,358,182	1,577,178	112,149	1,933,600	(3,724,150)	12,256,959
Equity in income of unconsolidated affiliates:						
Year ended December 31, 2007	6,031	9,540	12,628	1,459	—	29,658
Year ended December 31, 2006	5,715	2,872	11,909	1,069	—	21,565
Year ended December 31, 2005	5,553	2,384	6,125	486	—	14,548
Gross operating margin by individual business segment and in total:						
Year ended December 31, 2007	812,521	335,683	171,551	172,313	—	1,492,068
Year ended December 31, 2006	752,548	333,399	103,407	173,095	—	1,362,449
Year ended December 31, 2005	579,706	353,076	77,505	126,060	—	1,136,347
Segment assets:						
At December 31, 2007	4,570,555	3,702,297	1,452,568	687,856	1,173,988	11,587,264
At December 31, 2006	3,249,486	3,611,974	734,659	502,345	1,734,083	9,832,547
Investments in and advances to unconsolidated affiliates (see Note 11):						
At December 31, 2007	117,089	239,327	484,588	17,335	—	858,339
At December 31, 2006	111,229	124,591	310,136	18,603	—	564,559
Intangible Assets (see Note 13):						
At December 31, 2007	373,071	354,152	133,058	56,719	—	917,000
At December 31, 2006	417,950	386,149	152,376	47,480	—	1,003,955
Goodwill (see Note 13):						
At December 31, 2007	153,706	282,121	82,135	73,690	—	591,652
At December 31, 2006	152,595	282,121	82,135	73,690	—	590,541

In general, our historical operating results and/or financial position have been affected by business combinations and other acquisitions. The operating results of entities and assets we acquire are included in our financial results prospectively from their purchase dates.

Kinder Morgan Energy Partners, L.P.
2007 Form 10-K

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-11234

Kinder Morgan Energy Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0380342**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

500 Dallas, Suite 1000, Houston, Texas 77002
(Address of principal executive offices)(zip code)

Registrant's telephone number, including area code: 713-369-9000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Units	New York Stock Exchange

Securities registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 29, 2007 was approximately $8,185,538,074. As of January 31, 2008, the registrant had 170,224,734 Common Units outstanding.

PART I

Items 1 and 2. ***Business and Properties.***

In this report, unless the context requires otherwise, references to "we," "us," "our," "KMP" or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P., a Delaware limited partnership formed in August 1992, our operating limited partnerships and their subsidiaries. Our common units, which represent limited partner interests in us, trade on the New York Stock Exchange under the symbol "KMP." The address of our principal executive offices is 500 Dallas, Suite 1000, Houston, Texas 77002, and our telephone number at this address is (713) 369-9000. You should read the following discussion and analysis in conjunction with our consolidated financial statements included elsewhere in this report. All dollars in this report are United States dollars, except where stated otherwise. Canadian dollars are designated as C$.

(a) General Development of Business

Organizational Structure

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America. We own an interest in or operate more than 25,000 miles of pipelines and approximately 165 terminals. Our pipelines transport natural gas, gasoline, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals and handle bulk materials like coal and petroleum coke. We are also the leading provider of carbon dioxide, commonly called "CO_2," for enhanced oil recovery projects in North America. As one of the largest publicly traded pipeline limited partnerships in America, we have an enterprise value of approximately $20 billion.

Our general partner is Kinder Morgan G.P., Inc., a Delaware corporation. On July 27, 2007, our general partner issued and sold 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us, or two of our subsidiaries: SFPP, L.P. and Calnev Pipe Line LLC.

Knight Inc., a Kansas corporation and a private company formerly known as Kinder Morgan, Inc., indirectly is the sole owner of the common stock of our general partner. On August 28, 2006, Kinder Morgan, Inc., a Kansas corporation referred to as "KMI" in this report, entered into an agreement and plan of merger whereby generally each share of KMI common stock would be converted into the right to receive $107.50 in cash without interest. KMI in turn would merge with a wholly owned subsidiary of Knight Holdco LLC, a privately owned company in which Richard D. Kinder, Chairman and Chief Executive Officer of KMI, would be a major investor. On May 30, 2007, the merger closed, with KMI continuing as the surviving legal entity and subsequently renamed "Knight Inc.," referred to as "Knight" in this report. Additional investors in Knight Holdco LLC include the following: other senior members of Knight management, most of whom are also senior officers of Kinder Morgan G.P., Inc. (our general partner) and of Kinder Morgan Management, LLC (our general partner's delegate); KMI co-founder William V. Morgan; KMI board members Fayez Sarofim and Michael C. Morgan; and affiliates of (i) Goldman Sachs Capital Partners; (ii) American International Group, Inc.; (iii) The Carlyle Group; and (iv) Riverstone Holdings LLC. This transaction is referred to in this report as the "going-private transaction."

As of December 31, 2007, Knight and its consolidated subsidiaries owned, through its general and limited partner interests, an approximately 13.9% interest in us. In addition to the distributions it receives from its limited and general partner interests, Knight also receives an incentive distribution from us as a result of its ownership of our general partner. This incentive distribution is calculated in increments based on the amount by which quarterly distributions to our unitholders exceed specified target levels as set forth in our partnership agreement, reaching a maximum of 50% of distributions allocated to the general partner for distributions above $0.23375 per limited partner unit per quarter. Including both its general and limited partner interests in us, at the 2007 distribution level, Knight received approximately 49% of all quarterly "Available Cash" distributions (as defined in our partnership agreement) from us, with approximately 43% and 6% of all quarterly distributions from us attributable to Knight's general partner and limited partner interests, respectively. The actual level of distributions Knight will receive in the future will vary with the level of distributions to our limited partners determined in accordance with our partnership agreement.

Kinder Morgan Management, LLC, referred to as "KMR" in this report, is a Delaware limited liability company formed in February 2001. Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, our general partner has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. Under the delegation of control agreement, KMR, as the delegate of our general partner, manages and controls our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Furthermore, in accordance with its limited liability company agreement, KMR's activities are limited to being a limited partner in, and managing and controlling the business and affairs of us, our operating limited partnerships and their subsidiaries.

KMR's shares represent limited liability company interests and trade on the New York Stock Exchange under the symbol "KMR." Since its inception, KMR has used substantially all of the net proceeds received from the public offerings of its shares to purchase i-units from us. The i-units are a separate class of limited partner interests in us and are issued only to KMR. Under the terms of our partnership agreement, the holders of our i-units are entitled to vote on all matters on which the holders of our common units are entitled to vote.

In general, our limited partner units, consisting of i-units, common units and Class B units (the Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange), will vote together as a single class, with each i-unit, common unit and Class B unit having one vote. We pay our quarterly distributions from operations and interim capital transactions to our common and Class B unitholders in cash, and we pay our quarterly distributions to KMR in additional i-units rather than in cash. As of December 31, 2007, KMR, through its ownership of our i-units, owned approximately 29.2% of all of our outstanding limited partner units.

Recent Developments

The following is a brief listing of significant developments since December 31, 2006. Additional information regarding most of these items may be found elsewhere in this report.

- Effective January 1, 2007, we acquired the remaining approximate 50.2% interest in the Cochin pipeline system that we did not already own from affiliates of BP for an aggregate consideration of approximately $47.8 million, consisting of $5.5 million in cash and a note payable having a fair value of $42.3 million. As part of the transaction, the seller also agreed to reimburse us for certain pipeline integrity management costs over a five-year period in an aggregate amount not to exceed $50 million. Upon closing, we became the operator of the pipeline;

- On January 17, 2007, we announced that our CO_2 business segment will invest approximately $120 million to further expand its operations and enable it to meet the increased demand for carbon dioxide in the Permian Basin. The expansion activities will take place in southwest Colorado and include developing a new carbon dioxide source field (named the Doe Canyon Deep Unit that went in service during the first quarter of 2008) and adding infrastructure at both the McElmo Dome Unit and the Cortez Pipeline. The entire expansion is expected to be completed by the middle of 2008;

- On January 30, 2007, we completed a public offering of senior notes. We issued a total of $1.0 billion in principal amount of senior notes, consisting of $600 million of 6.00% notes due February 1, 2017, and $400 million of 6.50% notes due February 1, 2037. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $992.8 million, and we used the proceeds to reduce the borrowings under our commercial paper program;

- On February 14, 2007, the first phase of the Rockies Express pipeline system, the 327-mile REX-Entrega Project, was placed in service at a cost of approximately $745 million and provided up to 500 million cubic feet of natural gas capacity from the Meeker Hub in Rio Blanco County, Colorado and Wamsutter Hub in Sweetwater County, Wyoming to the Cheyenne Hub in Weld County, Colorado.

  The Rockies Express pipeline project is an approximate $4.9 billion, 1,679-mile natural gas pipeline system which is owned and currently being developed by Rockies Express Pipeline LLC. The Rockies Express pipeline project is to be completed in three phases: (i) a 327-mile, $745 million pipeline running from the Meeker Hub to the Cheyenne Hub with a nominal capacity of 500 million cubic feet per day; (ii) a 713-mile, $1.6 billion pipeline from the Cheyenne Hub to an interconnect in Audrain County, Missouri, transporting up to 1.5 billion cubic feet per day; and (iii) a 639-mile, $2.6 billion pipeline from Audrain County, Missouri to Clarington, located in Monroe County, Ohio. When fully completed, the Rockies Express pipeline system will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for all of the pipeline capacity. On January 12, 2008, interim service on the REX-West Project (second phase) commenced. Full service on the REX-West system for 1.5 billion cubic feet per day of contracted capacity is expected to commence in mid-March 2008. See "—(c) Narrative Description of Business—Business Segments—Natural Gas Pipelines—Rockies Express Pipeline" for more information;

- On February 28, 2007, we announced plans to invest up to $100 million to expand our liquids terminal facilities in order to help serve the growing biodiesel market. We entered into long-term agreements as lessors with Green Earth Fuels, LLC to build tankage that will handle biodiesel at our Houston Ship Channel liquids facility. Green Earth Fuels completed construction of an 86 million gallon biodiesel production facility at our Galena Park, Texas liquids terminal in the fourth quarter of 2007;

- On April 30, 2007, we acquired the Trans Mountain pipeline system from Knight for $549.1 million. The Trans Mountain pipeline system, which transports crude oil and refined products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington, currently transports approximately 260,000 barrels per day. An additional expansion that will increase capacity of the pipeline to 300,000 barrels per day is expected to be in service by November 2008. Current accounting principles require our consolidated financial statements and all other financial information included in this report to be stated to assume that the transfer of Trans Mountain net assets from Knight to us had occurred at the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006). As a result, financial statements and financial information presented for prior periods in this report have been restated to reflect our acquisition. In addition, due to the fact that Trans Mountain's operations are managed separately, involve different products and marketing strategies, and produce discrete financial information that is separately evaluated internally by our management, we have identified our Trans Mountain pipeline system as a separate reportable business segment. For additional information regarding this acquisition, see Note 3 to our consolidated financial statements;

- On May 14, 2007, we announced plans to construct a $72 million natural gas pipeline designed to bring new supplies out of East Texas to markets in the Houston and Beaumont, Texas areas. The new pipeline will consist of approximately 63 miles of 24-inch diameter pipe and multiple interconnections with other pipelines. It will connect our Kinder Morgan Tejas system in Harris County, Texas to our Kinder Morgan Texas Pipeline system in Polk County near Goodrich, Texas. In addition, we entered into a long-term binding agreement with CenterPoint Energy Services, Inc. to provide firm transportation for a significant portion of the initial project capacity, which will consist of approximately 225 million cubic feet per day of natural gas using existing compression and be expandable to over 400 million cubic feet per day with additional compression;

- On May 17, 2007, KMR closed the public offering of 5,700,000 of its shares at a price of $52.26 per share. The net proceeds from the offering were used by KMR to buy additional i-units from us. We used the proceeds of $297.9 million from our i-unit issuance to reduce the borrowings under our commercial paper program;

- On May 30, 2007, we purchased the Vancouver Wharves bulk marine terminal from British Columbia Railway Company, a crown corporation owned by the Province of British Columbia, for an aggregate consideration of $57.2 million, consisting of $38.8 million in cash and $18.4 million in assumed liabilities. The Vancouver Wharves facility is located on the north shore of the Port of Vancouver's main harbor, and includes five deep-sea vessel berths situated on a 139-acre site. The terminal assets include significant rail infrastructure, dry bulk and liquid storage, and material handling systems which allow the terminal to handle over 3.5 million tons of cargo annually;

- On June 21, 2007, we closed a public offering of $550 million in principal amount of 6.95% senior notes. The notes are due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $543.9 million, and we used the proceeds to reduce our commercial paper debt;

- On June 22, 2007, the Federal Energy Regulatory Commission, referred to in this report as the FERC, issued an order granting construction and operation of our Kinder Morgan Louisiana Pipeline project, and we officially accepted the order on July 10, 2007. The Kinder Morgan Louisiana Pipeline is expected to cost approximately $510 million and will provide approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal, located in Cameron Parish, Louisiana, to various delivery points in Louisiana and will provide interconnects with many other natural gas pipelines, including Natural Gas Pipeline Company of America. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total and is expected to be in service by January 1, 2009;

- On July 10, 2007, we announced a combined $41 million investment for two terminal expansions to help meet the growing need for terminal services in key markets along the Gulf Coast. The investment consists of (i) the construction of a terminal that will include liquids storage, transfer and packaging facilities at the Rubicon Plant site in Geismar, Louisiana; and (ii) the purchase of liquids storage tanks from Royal Vopak in Westwego, Louisiana. The tanks have a storage capacity of approximately 750,000 barrels for vegetable oil, biodiesel, ethanol and other liquids products. The new terminal being built in Geismar will be capable of handling inbound and outbound material via pipeline, rail, truck and barge/vessel. Construction is expected to be complete by the fourth quarter of 2008;

- On July 23, 2007, following the FERC's expedited approval of our CALNEV Pipeline's proposed tariff rate structure, we announced our continuing development of the approximate $426 million expansion of the pipeline system into Las Vegas, Nevada. The expansion involves the construction of a new 16-inch diameter pipeline, which will parallel existing utility corridors between Colton, California and Las Vegas in order to minimize environmental impacts. System capacity would increase to approximately 200,000 barrels per day upon completion of the expansion, and could be increased as necessary to over 300,000 barrels per day with the addition of pump stations. The CALNEV expansion is expected to be complete in early 2011;

- On August 6, 2007, Kinder Morgan Interstate Gas Transmission LLC, referred to in this report as KMIGT, filed for regulatory approval to construct and operate a 41-mile, $29 million natural gas pipeline from the Cheyenne Hub to markets in and around Greeley, Colorado. When completed, the Colorado Lateral expansion project will provide firm transportation of up to 55 million cubic feet per day to a local utility under long-term contract. On February 21, 2008, the FERC granted the certification application;

- On August 23, 2007, we announced that we have begun construction on the approximately C$467 million Anchor Loop project, the second phase of the Trans Mountain pipeline system expansion that will increase pipeline capacity from approximately 260,000 to 300,000 barrels of crude oil per day. The project is expected to be complete in November 2008. In April 2007, we commissioned 10 new pump stations which boosted capacity on Trans Mountain from 225,000 to approximately 260,000 barrels per day. The pipeline is currently operating at full capacity;

- On August 28, 2007, we closed a public offering of $500 million in principal amount of 5.85% senior notes. The notes are due September 15, 2012. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $497.8 million, and we used the proceeds to reduce our commercial paper debt;

- Effective September 1, 2007, we acquired five bulk terminal facilities from Marine Terminals, Inc. for an aggregate consideration of approximately $101.5 million, consisting of $100.3 million in cash and an assumed liability of $1.2 million. The acquired assets and operations are primarily involved in the handling and storage of steel and alloys, and also provide stevedoring and harbor services, scrap handling, and scrap processing services to customers in the steel and alloys industry. The operations are located in Blytheville, Arkansas; Decatur, Alabama; Hertford, North Carolina; and Berkley, South Carolina. Combined, the five facilities handled approximately 13.7 million tons of steel products in 2007. Under long-term contracts, the acquired terminal facilities will continue to provide handling, processing, harboring and warehousing services to Nucor Corporation, one of the nation's largest steel and steel products companies;

- Effective October 5, 2007, we sold our North System natural gas liquids and refined petroleum products pipeline system and our 50% ownership interest in the Heartland Pipeline Company to ONEOK Partners, L.P. for approximately $298.6 million in cash. Our investment in net assets, including all transaction related accruals, was approximately $145.8 million, most of which represented property, plant and equipment, and we recognized approximately $152.8 million of gain on the sale of these net assets. In accordance with generally accepted accounting principles, we accounted for the North System business as a discontinued operation for all periods presented in this report, and we reported the gain with the caption as "Gain on disposal of North System" on our accompanying consolidated statement of income;

- On October 9, 2007, Midcontinent Express Pipeline LLC filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the approximate 500-mile Midcontinent Express Pipeline natural gas transmission system. We own a 50% interest in Midcontinent Express Pipeline LLC and Energy Transfer Partners L.P. owns the remaining interest. The Midcontinent Express Pipeline will create long-haul, firm natural gas transportation takeaway capacity, either directly or indirectly, from natural gas producing regions located in Texas, Oklahoma and Arkansas. The total project is expected to cost approximately $1.3 billion, and will have an initial transportation capacity of approximately 1.4 billion cubic feet per day of natural gas.

  The Midcontinent Express Pipeline will originate near Bennington, Oklahoma and terminate at an interconnect with Williams' Transco natural gas pipeline system near Butler, Alabama. It will also connect to Natural Gas Pipeline Company of America's natural gas pipeline and to Energy Transfer Partners' 135-mile natural gas pipeline, which extends from the Barnett Shale natural gas producing area in North Texas to an interconnect with the Texoma Pipeline near Paris, Texas. The Midcontinent Express Pipeline now has long-term binding commitments from multiple shippers for approximately 1.2 billion cubic feet per day and, in order to provide a seamless transportation path from various locations in Oklahoma, the pipeline has also executed a firm capacity lease agreement with Enogex, Inc., an Oklahoma-based intrastate natural gas gathering and pipeline company that is wholly-owned by OGE Energy Corp. Subject to the receipt of regulatory approvals, construction of the pipeline is expected to commence in August 2008 and be in service during the first quarter of 2009.

  In January 2008, in conjunction with the signing of additional binding transportation commitments, Midcontinent Express and MarkWest entered into an option agreement which provides MarkWest a one-time right to purchase a 10% ownership interest in Midcontinent Express after the pipeline is fully constructed and placed into service. If the option is exercised, we and Energy Transfer Partners will each own 45% of Midcontinent Express, while MarkWest will own the remaining 10%;

- On October 17, 2007, we announced that we will invest approximately $23 million to expand our Kinder Morgan Interstate Gas Transmission pipeline system in order to serve five separate industrial plants (four of which produce ethanol) near Grand Island, Nebraska. The project is fully subscribed with long-term customer contracts, and subject to the receipt of regulatory approvals filed December 21, 2007, the expansion project is expected to be fully operational by the fall of 2008. Since 2000, our KMIGT system has connected to 17 new ethanol plants, 11 of which are located in the state of Nebraska;

- On November 26, 2007, we announced that we expect to declare cash distributions of $4.02 per unit for 2008, an almost 16% increase over our cash distributions of $3.48 per unit for 2007. This expectation includes contributions from assets owned by us as of the announcement date and does not include any potential benefits from unidentified acquisitions. Additionally, our expectation does not take into account any capital costs associated with financing the payment of reparations sought by shippers on our Pacific operations' interstate pipelines. Our expected growth in distributions in 2008 will be fueled by incremental earnings from Rockies Express-West (the western portion of the Rockies Express Pipeline), higher hedge prices on our

crude oil production (budgeted production volumes for the SACROC oil field unit in 2008 are approximately equal to the volumes realized in 2007), and an anticipated strong performance from our remaining business portfolio;

- In December 2007, we completed a public offering of 7,130,000 of our common units, including common units sold pursuant to the underwriters' over-allotment option, at a price of $48.09 per unit, less commissions and underwriting expenses. We received net proceeds of $342.9 million for the issuance of these 7,130,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program;

- In December 2007, we completed a second expansion of our Pacific operations' East Line pipeline segment. This expansion consisted of replacing approximately 130 miles of 12-inch diameter pipe between El Paso, Texas and Tucson, Arizona with new 16-inch diameter pipe, constructing additional pump stations, and adding new storage tanks at Tucson. The project, completed at a cost of approximately $154 million, will increase East Line capacity by 36% (to approximately 200,000 barrels per day) to meet the demand for refined petroleum products, and will provide the platform for further incremental expansions through horsepower additions to the system;

- On December 31, 2007, TransColorado Gas Transmission LLC completed an approximate $50 million expansion to provide up to 250 million cubic feet per day of natural gas transportation, starting January 1, 2008, from the Blanco Hub to an interconnect with the Rockies Express pipeline system at the Meeker Hub;

- During 2007, we spent $1,691.6 million for additions to our property, plant and equipment, including both expansion and maintenance projects. Our capital expenditures included the following:

  - $480.0 million in our Terminals segment, largely related to expanding the petroleum products storage capacity at our liquids terminal facilities, including the construction of additional liquids storage tanks at our facilities in Canada and at our facilities located on the Houston Ship Channel and the New York Harbor, and to various expansion projects and improvements undertaken at multiple terminal facilities;

  - $382.5 million in our CO_2 segment, mostly related to additional infrastructure, including wells and injection and compression facilities, to support the expanding carbon dioxide flooding operations at the SACROC and Yates oil field units in West Texas and to expand our capacity to produce and deliver CO_2 from our McElmo Dome and Doe Canyon Source Fields;

  - $305.7 million in our Trans Mountain segment, mostly related to pipeline expansion and improvement projects undertaken to increase crude oil and refined products delivery volumes;

  - $264.0 million in our Natural Gas Pipelines segment, mostly related to current construction of our Kinder Morgan Louisiana Pipeline and to various expansion and improvement projects on our Texas intrastate natural gas pipeline systems, including the development of additional natural gas storage capacity at our natural gas storage facilities located at Markham and Dayton, Texas; and

  - $259.4 million in our Products Pipelines segment, mostly related to the continued expansion work on our Pacific operations' East Line products pipeline, completion of construction projects resulting in additional capacity, and an additional refined products line on our CALNEV Pipeline in order to increase delivery service to the growing Las Vegas, Nevada market;

  Our capital expansion program in 2007 was approximately $2.6 billion (including our share of capital expenditures for both the Rockies Express and Midcontinent Express natural gas pipeline projects). Including all of our business acquisition expenditures, total spending was $3.3 billion. Our capital expansion program will continue to be significant in 2008, as we expect to invest approximately $3.3 billion in expansion capital expenditures (including our share of capital expenditures for both the Rockies Express and Midcontinent Express natural gas pipeline projects), which will help drive earnings and cash flow growth in 2009 and beyond;

- On January 16, 2008, we announced that we plan to invest approximately $56 million to construct a petroleum coke terminal at the BP refinery located in Whiting, Indiana. We have entered into a long-term contract to build and operate the facility, which will handle approximately 2.2 million tons of petroleum coke per year from a coker unit BP plans to construct to process heavy crude oil from Canada. The facility is expected to be in service in mid-year 2011;
- On February 12, 2008, we completed an additional public offering of senior notes. We issued a total of $900 million in principal amount of senior notes, consisting of $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program; and
- On February 12, 2008, we completed an additional offering of 1,080,000 of our common units at a price of $55.65 per unit in a privately negotiated transaction. We received net proceeds of $60.1 million for the issuance of these 1,080,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

(b) Financial Information about Segments

For financial information on our five reportable business segments, see Note 15 to our consolidated financial statements.

(c) Narrative Description of Business

Business Strategy

The objective of our business strategy is to grow our portfolio of businesses by:

- focusing on stable, fee-based energy transportation and storage assets that are core to the energy infrastructure of growing markets within North America;
- increasing utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- leveraging economies of scale from incremental acquisitions and expansions of assets that fit within our strategy and are accretive to cash flow and earnings; and
- maximizing the benefits of our financial structure to create and return value to our unitholders.

Business Segments

We own and manage a diversified portfolio of energy transportation and storage assets. Our operations are conducted through our five operating limited partnerships and their subsidiaries and are grouped into five reportable business segments. These segments are as follows:

- Products Pipelines—which consists of approximately 8,300 miles of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets; plus approximately 60 associated product terminals and petroleum pipeline transmix processing facilities serving customers across the United States;
- Natural Gas Pipelines—which consists of approximately 14,700 miles of natural gas transmission pipelines and gathering lines, plus natural gas storage, treating and processing facilities, through which natural gas is gathered, transported, stored, treated, processed and sold;

- CO_2 — which produces, markets and transports, through approximately 1,300 miles of pipelines, carbon dioxide to oil fields that use carbon dioxide to increase production of oil; owns interests in and/or operates ten oil fields in West Texas; and owns and operates a 450 mile crude oil pipeline system in West Texas;
- Terminals—which consists of approximately 108 owned or operated liquids and bulk terminal facilities and more than 45 rail transloading and materials handling facilities located throughout the United States and portions of Canada, which together transload, store and deliver a wide variety of bulk, petroleum, petrochemical and other liquids products for customers across the United States and Canada; and
- Trans Mountain—which consists of over 700 miles of common carrier pipelines, originating at Edmonton, Alberta, for the transportation of crude oil and refined petroleum to the interior of British Columbia and to marketing terminals and refineries located in the greater Vancouver, British Columbia area and Puget Sound in Washington State; plus five associated product terminals.

Generally, as utilization of our pipelines and terminals increases, our fee-based revenues increase. We do not face significant risks relating directly to short-term movements in commodity prices for two principal reasons. First, we primarily transport and/or handle products for a fee and are not engaged in significant unmatched purchases and resales of commodity products. Second, in those areas of our business where we do face exposure to fluctuations in commodity prices, primarily oil production in our CO_2 business segment, we engage in a hedging program to mitigate this exposure.

We regularly consider and enter into discussions regarding potential acquisitions, including those from Knight or its affiliates, and are currently contemplating potential acquisitions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, receipt of fairness opinions and approval of the parties' respective boards of directors. While there are currently no unannounced purchase agreements for the acquisition of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A "Risk Factors" below, there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

Products Pipelines

Our Products Pipelines segment consists of our refined petroleum products and natural gas liquids pipelines and their associated terminals, our Southeast terminals and our transmix processing facilities.

Pacific Operations

Our Pacific operations include our SFPP, L.P. operations, our CALNEV Pipeline operations and our West Coast Liquid Terminals operations. The assets include interstate common carrier pipelines regulated by the FERC, intrastate pipelines in the state of California regulated by the California Public Utilities Commission, and certain non rate-regulated operations and terminal facilities.

Our Pacific operations serve seven western states with approximately 3,000 miles of refined petroleum products pipelines and related terminal facilities that provide refined products to some of the fastest growing population centers in the United States, including California; Las Vegas and Reno, Nevada; and the Phoenix-Tucson, Arizona corridor. For 2007, the three main product types transported were gasoline (59%), diesel fuel (23%) and jet fuel (18%).

Our Pacific operations also includes CALNEV Pipeline which consists of two parallel 248-mile, 14-inch and 8-inch diameter pipelines that run from our facilities at Colton, California to Las Vegas, Nevada, and which also serves Nellis Air Force Base located in Las Vegas. It also includes approximately 55 miles of pipeline serving Edwards Air Force Base.

Our Pacific operations include 15 truck-loading terminals (13 on SFPP, L.P. and two on CALNEV) with an aggregate usable tankage capacity of approximately 13.7 million barrels. The truck terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and oxygenate blending.

Our Pacific operation's West Coast Liquid Terminals are fee-based terminals located in the Seattle, Portland, San Francisco and Los Angeles areas along the west coast of the United States with a combined total capacity of approximately 8.3 million barrels of storage for both petroleum products and chemicals.

Markets. Combined, our Pacific operations' pipelines transport approximately 1.3 million barrels per day of refined petroleum products, providing pipeline service to approximately 31 customer-owned terminals, 11 commercial airports and 14 military bases. Currently, our Pacific operations' pipelines serve approximately 100 shippers in the refined petroleum products market; the largest customers being major petroleum companies, independent refiners, and the United States military.

A substantial portion of the product volume transported is gasoline. Demand for gasoline depends on such factors as prevailing economic conditions, vehicular use patterns and demographic changes in the markets served. If current trends continue, we expect the majority of our Pacific operations' markets to maintain growth rates that will exceed the national average for the foreseeable future. The volume of products transported is affected by various factors, principally demographic growth, economic conditions, product pricing, vehicle miles traveled, population and fleet mileage. Certain product volumes can experience seasonal variations and, consequently, overall volumes may be lower during the first and fourth quarters of each year.

Supply. The majority of refined products supplied to our Pacific operations' pipeline system come from the major refining centers around Los Angeles, San Francisco, El Paso and Puget Sound, as well as from waterborne terminals and connecting pipelines located near these refining centers.

Competition. The two most significant competitors of our Pacific operations' pipeline system are proprietary pipelines owned and operated by major oil companies in the area where our pipeline system delivers products and also refineries with terminals that have trucking arrangements within our market areas. We believe that high capital costs, tariff regulation, and environmental and right-of-way permitting considerations make it unlikely that a competing pipeline system comparable in size and scope to our Pacific operations will be built in the foreseeable future. However, the possibility of individual pipelines being constructed or expanded to serve specific markets is a continuing competitive factor.

The use of trucks for product distribution from either shipper-owned proprietary terminals or from their refining centers continues to compete for short haul movements by pipeline. Our Pacific terminal operations compete with terminals owned by our shippers and by third party terminal operators in California, Arizona and Nevada. Competitors include Shell Oil Products U.S., BP (formerly Arco Terminal Services Company), Wilmington Liquid Bulk Terminals (Vopak), NuStar, and Chevron. We cannot predict with any certainty whether the use of short haul trucking will decrease or increase in the future.

Plantation Pipe Line Company

We own approximately 51% of Plantation Pipe Line Company, referred to in this report as Plantation, a 3,100-mile refined petroleum products pipeline system serving the southeastern United States. An affiliate of ExxonMobil owns the remaining 49% ownership interest. ExxonMobil is the largest shipper on the Plantation system both in terms of volumes and revenues. We operate the system pursuant to agreements with Plantation Services LLC and Plantation. Plantation serves as a common carrier of refined petroleum products to various metropolitan areas, including Birmingham, Alabama; Atlanta, Georgia; Charlotte, North Carolina; and the Washington, D.C. area.

For the year 2007, Plantation delivered an average of 535,672 barrels per day of refined petroleum products. These delivered volumes were comprised of gasoline (63%), diesel/heating oil (23%) and jet fuel (14%). Average delivery volumes for 2007 were 3.5% lower than the 555,063 barrels per day delivered during 2006. The decrease was predominantly driven by (i) the full year impact of alternative pipeline service (initial startup mid-2006) into Southeast markets, and (ii) changes in production patterns from Louisiana refineries related to refiners directing higher margin products (such as reformulated gasoline blendstock for oxygenate blending) into markets not directly served by Plantation.

Markets. Plantation ships products for approximately 30 companies to terminals throughout the southeastern United States. Plantation's principal customers are Gulf Coast refining and marketing companies, fuel wholesalers, and the United States Department of Defense. Plantation's top five shippers represent approximately 80% of total system volumes.

The eight states in which Plantation operates represent a collective pipeline demand of approximately two million barrels per day of refined petroleum products. Plantation currently has direct access to about 1.5 million barrels per day of this overall market. The remaining 0.5 million barrels per day of demand lies in markets (e.g., Nashville, Tennessee; North Augusta, South Carolina; Bainbridge, Georgia; and Selma, North Carolina) currently served by another pipeline company. Plantation also delivers jet fuel to the Atlanta, Georgia; Charlotte, North Carolina; and Washington, D.C. airports (Ronald Reagan National and Dulles). Combined jet fuel shipments to these four major airports increased 3% in 2007 compared to 2006, with the majority of this growth occurring at Dulles Airport.

Supply. Products shipped on Plantation originate at various Gulf Coast refineries from which major integrated oil companies and independent refineries and wholesalers ship refined petroleum products. Plantation is directly connected to and supplied by a total of ten major refineries representing approximately 2.3 million barrels per day of refining capacity.

Competition. Plantation competes primarily with the Colonial pipeline system, which also runs from Gulf Coast refineries throughout the southeastern United States and extends into the northeastern states.

Central Florida Pipeline

Our Central Florida pipeline system consists of a 110-mile, 16-inch diameter pipeline that transports gasoline and an 85-mile, 10-inch diameter pipeline that transports diesel fuel and jet fuel from Tampa to Orlando, with an intermediate delivery point on the 10-inch pipeline at Intercession City, Florida. In addition to being connected to our Tampa terminal, the pipeline system is connected to terminals owned and operated by TransMontaigne, Citgo, BP, and Marathon Petroleum. The 10-inch diameter pipeline is connected to our Taft, Florida terminal (located near Orlando) and is also the sole pipeline supplying jet fuel to the Orlando International Airport in Orlando, Florida. In 2007, the pipeline system transported approximately 113,800 barrels per day of refined products, with the product mix being approximately 69% gasoline, 12% diesel fuel, and 19% jet fuel.

We also own and operate liquids terminals in Tampa and Taft, Florida. The Tampa terminal contains approximately 1.5 million barrels of storage capacity and is connected to two ship dock facilities in the Port of Tampa. The Tampa terminal provides storage for gasoline, diesel fuel and jet fuel for further movement into either trucks or into the Central Florida pipeline system. The Tampa terminal also provides storage and truck rack blending services for ethanol and bio-diesel. The Taft terminal contains approximately 0.7 million barrels of storage capacity, for gasoline and diesel fuel for further movement into trucks.

Markets. The estimated total refined petroleum products demand in the state of Florida is approximately 800,000 barrels per day. Gasoline is, by far, the largest component of that demand at approximately 545,000 barrels per day. The total refined petroleum products demand for the Central Florida region of the state, which includes the Tampa and Orlando markets, is estimated to be approximately 360,000 barrels per day, or 45% of the consumption of refined products in the state. We distribute approximately 150,000 barrels of refined petroleum products per day, including the Tampa terminal truck loadings. The balance of the market is supplied primarily by trucking firms and marine transportation firms. Most of the jet fuel used at Orlando International Airport is moved through our Tampa terminal and the Central Florida pipeline system. The market in Central Florida is seasonal, with demand peaks in March and April during spring break and again in the summer vacation season, and is also heavily influenced by tourism, with Disney World and other attractions located near Orlando.

Supply. The vast majority of refined petroleum products consumed in Florida is supplied via marine vessels from major refining centers in the Gulf Coast of Louisiana and Mississippi and refineries in the Caribbean basin. A lesser amount of refined petroleum products is being supplied by refineries in Alabama and by Texas Gulf Coast refineries via marine vessels and through pipeline networks that extend to Bainbridge, Georgia. The supply into Florida is generally transported by ocean-going vessels to the larger metropolitan ports, such as Tampa, Port Everglades near Miami, and Jacksonville. Individual markets are then supplied from terminals at these ports and other smaller ports, predominately by trucks, except the Central Florida region, which is served by a combination of trucks and pipelines.

Competition. With respect to the Central Florida pipeline system, the most significant competitors are trucking firms and marine transportation firms. Trucking transportation is more competitive in serving markets close to the marine terminals on the east and west coasts of Florida. We are utilizing tariff incentives to attract volumes to the pipeline that might otherwise enter the Orlando market area by truck from Tampa or by marine vessel into Cape Canaveral. We believe it is unlikely that a new pipeline system comparable in size and scope to our Central Florida Pipeline system will be constructed, due to the high cost of pipeline construction, tariff regulation and environmental and right-of-way permitting in Florida. However, the possibility of such a pipeline or a smaller capacity pipeline being built is a continuing competitive factor.

With respect to the terminal operations at Tampa, the most significant competitors are proprietary terminals owned and operated by major oil companies, such as Marathon Petroleum, BP and Citgo, located along the Port of Tampa, and the Chevron and Motiva terminals in Port Tampa. These terminals generally support the storage requirements of their parent or affiliated companies' refining and marketing operations and provide a mechanism for an oil company to enter into exchange contracts with third parties to serve its storage needs in markets where the oil company may not have terminal assets.

Federal regulation of marine vessels, including the requirement under the Jones Act that United States-flagged vessels contain double-hulls, is a significant factor influencing the availability of vessels that transport refined petroleum products. Marine vessel owners are phasing in the requirement based on the age of the vessel and some older vessels are being redeployed into use in other jurisdictions rather than being retrofitted with a double-hull for use in the United States.

Cochin Pipeline System

Our Cochin pipeline system consists of an approximate 1,900-mile, 12-inch diameter multi-product pipeline operating between Fort Saskatchewan, Alberta and Windsor, Ontario, including five terminals.

The pipeline operates on a batched basis and has an estimated system capacity of approximately 70,000 barrels per day. It includes 31 pump stations spaced at 60 mile intervals and five United States propane terminals. Underground storage is available at Fort Saskatchewan, Alberta and Windsor, Ontario through third parties. In 2007, the pipeline system transported approximately 40,600 barrels per day of natural gas liquids.

Markets. The pipeline traverses three provinces in Canada and seven states in the United States transporting high vapor pressure ethane, propane, butane and natural gas liquids to the Midwestern United States and eastern Canadian petrochemical and fuel markets. Current operations involve only the transportation of propane on Cochin.

Supply. Injection into the system can occur from BP, Provident, Keyera or Dow facilities with connections at Fort Saskatchewan, Alberta and from Spectra at interconnects at Regina and Richardson, Saskatchewan.

Competition. The pipeline competes with railcars and Enbridge Energy Partners for natural gas liquids long-haul business from Fort Saskatchewan, Alberta and Windsor, Ontario. The pipeline's primary competition in the Chicago natural gas liquids market comes from the combination of the Alliance pipeline system, which brings unprocessed gas into the United States from Canada, and from Aux Sable, which processes and markets the natural gas liquids in the Chicago market.

Cypress Pipeline

Our Cypress pipeline is an interstate common carrier natural gas liquids pipeline originating at storage facilities in Mont Belvieu, Texas and extending 104 miles east to a major petrochemical producer in the Lake Charles, Louisiana area. Mont Belvieu, located approximately 20 miles east of Houston, is the largest hub for natural gas liquids gathering, transportation, fractionation and storage in the United States.

Markets. The pipeline was built to service Westlake Petrochemicals Corporation in the Lake Charles, Louisiana area under a 20-year ship-or-pay agreement that expires in 2011. The contract requires a minimum volume of 30,000 barrels per day.

Supply. The Cypress pipeline originates in Mont Belvieu where it is able to receive ethane and ethane/propane mix from local storage facilities. Mont Belvieu has facilities to fractionate natural gas liquids received from several pipelines into ethane and other components. Additionally, pipeline systems that transport natural gas liquids from major producing areas in Texas, New Mexico, Louisiana, Oklahoma and the Mid-Continent Region supply ethane and ethane/propane mix to Mont Belvieu.

Competition. The pipeline's primary competition into the Lake Charles market comes from Louisiana onshore and offshore natural gas liquids.

Southeast Terminals

Our Southeast terminal operations consist of Kinder Morgan Southeast Terminals LLC and its consolidated affiliate, Guilford County Terminal Company, LLC. Kinder Morgan Southeast Terminals LLC, a wholly-owned subsidiary referred to in this report as KMST, was formed for the purpose of acquiring and operating high-quality liquid petroleum products terminals located primarily along the Plantation/Colonial pipeline corridor in the Southeastern United States.

Combined, our Southeast terminal operations consist of 24 petroleum products terminals with a total storage capacity of approximately 8.0 million barrels. These terminals transferred approximately 361,000 barrels of refined products per day during 2007 and approximately 347,000 barrels of refined products per day during 2006.

Markets . KMST's acquisition and marketing activities are focused on the Southeastern United States from Mississippi through Virginia, including Tennessee. The primary function involves the receipt of petroleum products from common carrier pipelines, short-term storage in terminal tankage, and subsequent loading onto tank trucks. KMST also offered ethanol blending and storage services in northern Virginia during 2007. Longer term storage is available at many of the terminals. KMST has a physical presence in markets representing almost 80% of the pipeline-supplied demand in the Southeast and offers a competitive alternative to marketers seeking a relationship with a truly independent truck terminal service provider.

Supply. Product supply is predominately from Plantation and/or Colonial pipelines. To the maximum extent practicable, we endeavor to connect KMST terminals to both Plantation and Colonial.

Competition . There are relatively few independent terminal operators in the Southeast. Most of the refined petroleum products terminals in this region are owned by large oil companies (BP, Motiva, Citgo, Marathon, and Chevron) who use these assets to support their own proprietary market demands as well as product exchange activity. These oil companies are not generally seeking third party throughput customers. Magellan Midstream Partners and TransMontaigne Product Services represent the other significant independent terminal operators in this region.

Transmix Operations

Our Transmix operations include the processing of petroleum pipeline transmix, a blend of dissimilar refined petroleum products that have become co-mingled in the pipeline transportation process. During pipeline transportation, different products are transported through the pipelines abutting each other, and generate a volume of different mixed products called transmix. At our transmix processing facilities, we process and separate pipeline transmix into pipeline-quality gasoline and light distillate products. We process transmix at six separate processing facilities located in Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; Indianola, Pennsylvania; Wood River, Illinois; and Greensboro, North Carolina. Combined, our transmix facilities processed approximately 10.4 million barrels of transmix in 2007 and approximately 9.1 million barrels in 2006.

In 2007, we increased the processing capacity of the recently constructed Greensboro, North Carolina transmix facility to better serve the needs of Plantation. The facility, which is located within KMST's refined products tank farm, now has the capability to process approximately 8,500 barrels of transmix per day. In addition to providing additional processing business, the facility continues to provide Plantation a lower cost alternative compared to other transmix processing arrangements that recover ultra low sulfur diesel, and also more fully utilizes current KMST tankage at the Greensboro, North Carolina tank farm.

Markets. The Gulf and East Coast refined petroleum products distribution system, particularly the Mid-Atlantic region, is the target market for our East Coast transmix processing operations. The Mid-Continent area and the New York Harbor are the target markets for our Illinois and Pennsylvania assets, respectively. Our West Coast transmix processing operations support the markets served by our Pacific operations in Southern California.

Supply. Transmix generated by Plantation, Colonial, Explorer, Sun, Teppco, and our Pacific operations provide the vast majority of the supply. These suppliers are committed to the use of our transmix facilities under long-term contracts. Individual shippers and terminal operators provide additional supply. Shell acquires transmix for processing at Indianola, Richmond and Wood River; Colton is supplied by pipeline shippers of our Pacific operations; Dorsey Junction is supplied by Colonial Pipeline Company and Greensboro is supplied by Plantation.

Competition. Placid Refining is our main competitor in the Gulf Coast area. There are various processors in the Mid-Continent area, primarily ConocoPhillips, Gladieux Refining and Williams Energy Services, who compete with our transmix facilities. Motiva Enterprises's transmix facility located near Linden, New Jersey is the principal competition for New York Harbor transmix supply and for our Indianola facility. A number of smaller organizations operate transmix processing facilities in the West and Southwest. These operations compete for supply that we envision as the basis for growth in the West and Southwest. Our Colton processing facility also competes with major oil company refineries in California.

Natural Gas Pipelines

Our Natural Gas Pipelines segment contains both interstate and intrastate pipelines. Its primary businesses consist of natural gas sales, transportation, storage, gathering, processing and treating. Within this segment, we own approximately 14,700 miles of natural gas pipelines and associated storage and supply lines that are strategically located at the center of the North American pipeline grid. Our transportation network provides access to the major gas supply areas in the western United States, Texas and the Midwest, as well as major consumer markets.

Texas Intrastate Natural Gas Pipeline Group

The group, which operates primarily along the Texas Gulf Coast, consists of the following four natural gas pipeline systems:

- our Kinder Morgan Texas Pipeline;
- our Kinder Morgan Tejas Pipeline;
- our Mier-Monterrey Mexico Pipeline; and
- our Kinder Morgan North Texas Pipeline.

The two largest systems in the group are our Kinder Morgan Texas Pipeline and our Kinder Morgan Tejas Pipeline. These pipelines essentially operate as a single pipeline system, providing customers and suppliers with improved flexibility and reliability. The combined system includes approximately 6,000 miles of intrastate natural gas pipelines with a peak transport and sales capacity of approximately 5.2 billion cubic feet per day of natural gas and approximately 120 billion cubic feet of system natural gas storage capacity. In addition, the combined system, through owned assets and contractual arrangements with third parties, has the capability to process 915 million cubic feet per day of natural gas for liquids extraction and to treat approximately 250 million cubic feet per day of natural gas for carbon dioxide removal.

Collectively, the combined system primarily serves the Texas Gulf Coast by selling, transporting, processing and treating gas from multiple onshore and offshore supply sources to serve the Houston/Beaumont/Port Arthur industrial markets, local gas distribution utilities, electric utilities and merchant power generation markets. It serves as a buyer and seller of natural gas, as well as a transporter of natural gas. The purchases and sales of natural gas are primarily priced with reference to market prices in the consuming region of its system. The difference between the purchase and sale prices is the rough equivalent of a transportation fee and fuel costs.

Included in the operations of our Kinder Morgan Tejas system is our Kinder Morgan Border Pipeline system. Kinder Morgan Border owns and operates an approximately 97-mile, 24-inch diameter pipeline that extends from a point of interconnection with the pipeline facilities of Pemex Gas Y Petroquimica Basica at the International Border between the United States and Mexico, to a point of interconnection with other intrastate pipeline facilities of Kinder Morgan Tejas located at King Ranch, Kleburg County, Texas. The 97-mile pipeline, referred to as the import/export facility, is capable of importing Mexican gas into the United States, and exporting domestic gas to Mexico. The imported Mexican gas is received from, and the exported domestic gas is delivered to, Pemex. The capacity of the import/export facility is approximately 300 million cubic feet of natural gas per day.

Our Mier-Monterrey Pipeline consists of a 95-mile, 30-inch diameter natural gas pipeline that stretches from south Texas to Monterrey, Mexico and can transport up to 375 million cubic feet per day. The pipeline connects to a 1,000-megawatt power plant complex and to the PEMEX natural gas transportation system. We have entered into a long-term contract (expiring in 2018) with Pemex, which has subscribed for all of the pipeline's capacity.

Our Kinder Morgan North Texas Pipeline consists of an 86-mile, 30-inch diameter pipeline that transports natural gas from an interconnect with the facilities of Natural Gas Pipeline Company of America LLC, referred to in this report as NGPL, in Lamar County, Texas to a 1,750-megawatt electric generating facility located in Forney, Texas, 15 miles east of Dallas, Texas. It has the capacity to transport 325 million cubic feet per day of natural gas and is fully subscribed under a long-term contract that expires in 2032. In 2006, the existing system was enhanced to be bi-directional, so that deliveries of additional supply coming out of the Barnett Shale area can be delivered into NGPL's pipeline as well as power plants in the area.

We also own and operate various gathering systems in South and East Texas. These systems aggregate natural gas supplies into our main transmission pipelines, and in certain cases, aggregate natural gas that must be processed or treated at its own or third-party facilities. We own plants that can process up to 115 million cubic feet per day of natural gas for liquids extraction. In addition, we have contractual rights to process approximately 800 million cubic feet per day of natural gas at various third-party owned facilities. We also own and operate three natural gas treating plants that provide carbon dioxide and/or hydrogen sulfide removal. We can treat up to 155 million cubic feet per day of natural gas for carbon dioxide removal at our Fandango Complex in Zapata County, Texas, 50 million cubic feet per day of natural gas at our Indian Rock Plant in Upshur County, Texas and approximately 45 million cubic feet per day of natural gas at our Thompsonville Facility located in Jim Hogg County, Texas.

Our North Dayton natural gas storage facility, located in Liberty County, Texas, has two existing storage caverns providing approximately 6.3 billion cubic feet of total capacity, consisting of 4.2 billion cubic feet of working capacity and 2.1 billion cubic feet of cushion gas. We have entered into a long-term storage capacity and transportation agreement with NRG covering two billion cubic feet of natural gas working capacity that expires in March 2017. In June 2006, we announced an expansion project that will significantly increase natural gas storage capacity at our North Dayton facility. The project is now expected to cost between $105 million and $115 million and involves the development of a new underground storage cavern that will add an estimated 6.5 billion cubic feet of incremental working natural gas storage capacity. The additional capacity is expected to be available in mid-2010.

We also own the West Clear Lake natural gas storage facility located in Harris County, Texas. Under a long term contract that expires in 2012, Coral Energy Resources, L.P. operates the facility and controls the 96 billion cubic feet of natural gas working capacity, and we provide transportation service into and out of the facility.

Additionally, we lease a salt dome storage facility located near Markham, Texas according to the provisions of an operating lease that expires in March 2013. We can, at our sole option, extend the term of this lease for two additional ten-year periods. The facility was expanded in 2007 and now consists of four salt dome caverns with approximately 17.3 billion cubic feet of working natural gas capacity and up to 1.1 billion cubic feet per day of peak deliverability. We also lease two salt dome caverns, known as the Stratton Ridge Facilities, from BP America Production Company in Brazoria County, Texas. The Stratton Ridge Facilities have a combined working natural gas capacity of 1.4 billion cubic feet and a peak day deliverability of 100 million cubic feet per day. A lease with Dow Hydrocarbon & Resources, Inc. for a salt dome cavern containing approximately 5.0 billion cubic feet of working capacity expired during the third quarter of 2007.

Markets. Texas is one of the largest natural gas consuming states in the country. The natural gas demand profile in our Texas intrastate pipeline group's market area is primarily composed of industrial (including on-site cogeneration facilities), merchant and utility power, and local natural gas distribution consumption. The industrial demand is primarily year-round load. Merchant and utility power demand peaks in the summer months and is complemented by local natural gas distribution demand that peaks in the winter months. As new merchant gas fired generation has come online and displaced traditional utility generation, we have successfully attached many of these new generation facilities to our pipeline systems in order to maintain and grow our share of natural gas supply for power generation. Additionally, in 2007, we have increased our capability and commitment to serve the growing local natural gas distribution market in the greater Houston metropolitan area.

We serve the Mexico market through interconnection with the facilities of Pemex at the United States-Mexico border near Arguellas, Mexico and our Mier-Monterrey Mexico pipeline. In 2007, deliveries through the existing interconnection near Arguellas fluctuated from zero to approximately 206 million cubic feet per day of natural gas, and there were several days of exports to the United States which ranged up to 250 million cubic feet per day. Deliveries to Monterrey also generally ranged from zero to 312 million cubic feet per day. We primarily provide transport service to these markets on a fee for service basis, including a significant demand component, which is paid regardless of actual throughput. Revenues earned from our activities in Mexico are paid in U.S. dollar equivalent.

Supply. We purchase our natural gas directly from producers attached to our system in South Texas, East Texas, West Texas and along the Texas Gulf Coast. In addition, we also purchase gas at interconnects with third-party interstate and intrastate pipelines. While our intrastate group does not produce gas, it does maintain an active well connection program in order to offset natural declines in production along its system and to secure supplies for additional demand in its market area. Our intrastate system has access to both onshore and offshore sources of supply, and is well positioned to interconnect with liquefied natural gas projects currently under development by others along the Texas Gulf Coast.

Competition. The Texas intrastate natural gas market is highly competitive, with many markets connected to multiple pipeline companies. We compete with interstate and intrastate pipelines, and their shippers, for attachments to new markets and supplies and for transportation, processing and treating services.

Rocky Mountain Natural Gas Pipeline Group

The group, which operates primarily along the Rocky Mountain region of the Western portion of the United States, consists of the following four natural gas pipeline systems:

- our Kinder Morgan Interstate Gas Transmission Pipeline;
- our Trailblazer Pipeline;
- our Trans-Colorado Pipeline; and
- our 51% ownership interest in the Rockies Express Pipeline.

Kinder Morgan Interstate Gas Transmission LLC

Kinder Morgan Interstate Gas Transmission LLC, referred to in this report as KMIGT, owns approximately 5,100 miles of transmission lines in Wyoming, Colorado, Kansas, Missouri and Nebraska. The pipeline system is powered by 28 transmission and storage compressor stations with approximately 160,000 horsepower. KMIGT also owns the Huntsman natural gas storage facility, located in Cheyenne County, Nebraska, which has approximately 10 billion cubic feet of firm capacity commitments and provides for withdrawal of up to 169 million cubic feet of natural gas per day.

Under transportation agreements and FERC tariff provisions, KMIGT offers its customers firm and interruptible transportation and storage services, including no-notice service and park and loan services. For these services, KMIGT charges rates which include the retention of fuel and gas lost and unaccounted for in-kind. Under KMIGT's tariffs, firm transportation and storage customers pay reservation charges each month plus a commodity charge based on the actual transported or stored volumes. In contrast, interruptible transportation and storage customers pay a commodity charge based upon actual transported and/or stored volumes. Under the no-notice service, customers pay a fee for the right to use a combination of firm storage and firm transportation to effect deliveries of natural gas up to a specified volume without making specific nominations. KMIGT also has the authority to make gas purchases and sales, as needed for system operations, pursuant to its currently effective FERC gas tariff.

KMIGT also offers its Cheyenne Market Center service, which provides nominated storage and transportation service between its Huntsman storage field and multiple interconnecting pipelines at the Cheyenne Hub, located in Weld County, Colorado. This service is fully subscribed through May 2014.

Markets. Markets served by KMIGT provide a stable customer base with expansion opportunities due to the system's access to growing Rocky Mountain supply sources. Markets served by KMIGT are comprised mainly of local natural gas distribution companies and interconnecting interstate pipelines in the mid-continent area. End-users of the local natural gas distribution companies typically include residential, commercial, industrial and agricultural customers. The pipelines interconnecting with KMIGT in turn deliver gas into multiple markets including some of the largest population centers in the Midwest. Natural gas demand to power pumps for crop irrigation during the summer from time-to-time exceeds heating season demand and provides KMIGT relatively consistent volumes throughout the year. In addition, KMIGT has seen a significant increase in demand from ethanol producers, and is actively seeking ways to meet the demands from the ethanol producing community.

Supply. Approximately 7%, by volume, of KMIGT's firm contracts expire within one year and 51% expire within one to five years. Over 99% of the system's total firm transport capacity is currently subscribed, with 78% of the total contracted capacity held by KMIGT's top nine shippers.

Competition. KMIGT competes with other interstate and intrastate gas pipelines transporting gas from the supply sources in the Rocky Mountain and Hugoton Basins to mid-continent pipelines and market centers.

Trailblazer Pipeline Company LLC

Our subsidiary, Trailblazer Pipeline Company LLC, owns a 436-mile natural gas pipeline system. Trailblazer's pipeline originates at an interconnection with Wyoming Interstate Company Ltd.'s pipeline system near Rockport, Colorado and runs through southeastern Wyoming to a terminus near Beatrice, Nebraska where it interconnects with NGPL and Northern Natural Gas Company's pipeline systems. NGPL, an investee of Knight, manages, maintains and operates Trailblazer, for which it is reimbursed at cost.

Trailblazer provides transportation services to third-party natural gas producers, marketers, local distribution companies and other shippers. Pursuant to transportation agreements and FERC tariff provisions, Trailblazer offers its customers firm and interruptible transportation. Under Trailblazer's tariffs, firm transportation customers pay reservation charges each month plus a commodity charge based on actual volumes transported. Interruptible transportation customers pay a commodity charge based upon actual volumes transported.

Markets. Significant growth in Rocky Mountain natural gas supplies has prompted a need for additional pipeline transportation service. Trailblazer has a certificated capacity of 846 million cubic feet per day of natural gas.

Supply. As of December 31, 2007, none of Trailblazer's firm contracts, by volume, expire before one year and 54%, by volume, expire within one to five years. Affiliated entities have contracted for less than 1% of the total firm transportation capacity. All of the system's firm transport capacity is currently subscribed.

Competition. The main competition that Trailblazer currently faces is that the gas supply in the Rocky Mountain area either stays in the area or is moved west and therefore is not transported on Trailblazer's pipeline. In addition, El Paso's Cheyenne Plains Pipeline can transport approximately 730 million cubic feet per day of natural gas from Weld County, Colorado to Greensburg, Kansas and competes with Trailblazer for natural gas pipeline transportation demand from the Rocky Mountain area. Additional competition could come from the Rockies Express pipeline system or from proposed pipeline projects. No assurance can be given that additional competing pipelines will not be developed in the future.

TransColorado Gas Transmission Company LLC

Our subsidiary, TransColorado Gas Transmission Company LLC, owns a 300-mile interstate natural gas pipeline that extends from approximately 20 miles southwest of Meeker, Colorado to Bloomfield, New Mexico. It has multiple points of interconnection with various interstate and intrastate pipelines, gathering systems, and local distribution companies. The pipeline system is powered by eight compressor stations having an aggregate of approximately 39,000 horsepower. Knight manages, maintains and operates TransColorado, for which it is reimbursed at cost.

TransColorado has the ability to flow gas south or north. TransColorado receives gas from one coal seam natural gas treating plant located in the San Juan Basin of Colorado and from pipeline, processing plant and gathering system interconnections within the Paradox and Piceance Basins of western Colorado. Gas flowing south through the pipeline moves onto the El Paso, Transwestern and Questar Southern Trail pipeline systems. Gas moving north flows into the Colorado Interstate, Wyoming Interstate and Questar pipeline systems at the Greasewood Hub and the Rockies Express pipeline system at the Meeker Hub. TransColorado provides transportation services to third-party natural gas producers, marketers, gathering companies, local distribution companies and other shippers.

Pursuant to transportation agreements and FERC tariff provisions, TransColorado offers its customers firm and interruptible transportation and interruptible park and loan services. For these services, TransColorado charges rates which include the retention of fuel and gas lost and unaccounted for in-kind. Under TransColorado's tariffs, firm transportation customers pay reservation charges each month plus a commodity charge based on actual volumes transported. Interruptible transportation customers pay a commodity charge based upon actual volumes transported. The underlying reservation and commodity charges are assessed pursuant to a maximum recourse rate structure, which does not vary based on the distance gas is transported. TransColorado has the authority to negotiate rates with customers if it has first offered service to those customers under its reservation and commodity charge rate structure.

TransColorado's approximately $50 million Blanco-Meeker Expansion Project was completed in the fourth quarter of 2007 and placed into service on January 1, 2008. The project boosted capacity on the pipeline by approximately 250 million cubic feet per day of natural gas from the Blanco Hub area in San Juan County, New Mexico through TransColorado's existing pipeline for deliveries to the Rockies Express Pipeline at an existing point of interconnection located at the Meeker Hub in Rio Blanco County, Colorado. All of the incremental capacity is subscribed under a long-term contract with ConocoPhillips.

Markets. TransColorado acts principally as a feeder pipeline system from the developing natural gas supply basins on the Western Slope of Colorado into the interstate natural gas pipelines that lead away from the Blanco Hub area of New Mexico and the interstate natural gas pipelines that lead away eastward from northwestern Colorado and southwestern Wyoming. TransColorado is one of the largest transporters of natural gas from the Western Slope supply basins of Colorado and provides a competitively attractive outlet for that developing natural gas resource. In 2007, TransColorado transported an average of approximately 734 million cubic feet per day of natural gas from these supply basins.

Supply. During 2007, 94% of TransColorado's transport business was with producers or their own marketing affiliates, and 6% was with marketing companies and various gas marketers. Approximately 64% of TransColorado's transport business in 2007 was conducted with its two largest customers. All of TransColorado's southbound pipeline capacity is committed under firm transportation contracts that extend at least through year-end 2008. TransColorado's pipeline capacity is 62% subscribed during 2009 through 2012, and TransColorado is actively pursuing contract extensions and or replacement contracts to increase firm subscription levels beyond 2008.

Competition. TransColorado competes with other transporters of natural gas in each of the natural gas supply basins it serves. These competitors include both interstate and intrastate natural gas pipelines and natural gas gathering systems. TransColorado's shippers compete for market share with shippers drawing upon gas production facilities within the New Mexico portion of the San Juan Basin. TransColorado has phased its past construction and expansion efforts to coincide with the ability of the interstate pipeline grid at Blanco, New Mexico to accommodate greater natural gas volumes. TransColorado's transport concurrently ramped up over that period such that TransColorado now enjoys a growing share of the outlet from the San Juan Basin to the southwestern United States marketplace.

Historically, the competition faced by TransColorado with respect to its natural gas transportation services has generally been based upon the price differential between the San Juan and Rocky Mountain basins. New pipelines servicing these producing basins have had the effect of reducing that price differential; however, given the growth in the Piceance and Paradox basins and the direct accessibility of the TransColorado system to these basins, we believe that TransColorado's transport business to be sustainable and not significantly impacted by any new entry of competition.

Rockies Express Pipeline

We operate and currently own 51% of the 1,679-mile Rockies Express Pipeline system, which when fully completed, will be one of the largest natural gas pipelines ever constructed in North America. The approximately $4.9 billion project will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for virtually all of the pipeline capacity.

Our ownership is through our 51% interest in West2East Pipeline LLC. the sole owner of Rockies Express Pipeline LLC. Sempra Pipelines & Storage, a unit of Sempra Energy, and ConocoPhillips hold the remaining ownership interests in the Rockies Express project. We account for our investment under the equity method of accounting due to the fact that our ownership interest will be reduced to 50% when construction of the entire project is completed. At that time, the capital accounts of West2East Pipeline LLC will be trued up to reflect our 50% economics in the project. We do not anticipate any additional changes in the ownership structure of the project.

On August 9, 2005, the FERC approved Rockies Express Pipeline LLC's application to construct 327 miles of pipeline facilities in two phases. Phase I consisted of the following two pipeline segments: (i) a 136-mile, 36-inch diameter pipeline that extends from the Meeker Hub in Rio Blanco County, Colorado to the Wamsutter Hub in Sweetwater County, Wyoming; and (ii) a 191-mile, 42-inch diameter pipeline that extends from the Wamsutter Hub to the Cheyenne Hub in Weld County, Colorado. Phase II of the project includes the construction of three compressor stations referred to as the Meeker, Big Hole and Wamsutter compressor stations. The Meeker and Wamsutter stations were completed and placed in-service in January 2008. Construction of the Big Hole compressor station is planned to commence in the second quarter of 2008, in order to meet an expected in-service date of June 30, 2009.

On April 19, 2007 the FERC issued a final order approving Rockies Express Pipeline LLC's application for authorization to construct and operate certain facilities comprising its proposed Rockies Express-West Project. This project is the first planned segment extension of the Rockies Express Pipeline LLC's original certificated facilities, and is comprised of approximately 713 miles of 42-inch diameter pipeline extending eastward from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The segment extension transports approximately 1.5 billion cubic feet per day of natural gas across the following five states: Wyoming, Colorado, Nebraska, Kansas and Missouri and includes certain improvements to pre-existing Rockies Express facilities located to the west of the Cheyenne Hub. Construction of the Rockies Express-West project commenced on May 21, 2007, and interim firm transportation service with capacity of approximately 1.4 billion cubic feet per day began January 12, 2008. The entire project (Rockies Express-West pipeline segment) is expected to become fully operational in mid-March 2008.

On April 30, 2007, Rockies Express Pipeline LLC filed an application with the FERC requesting approval to construct and operate the REX-East Project, the third segment of the Rockies Express pipeline system. The REX-East Project will be comprised of approximately 639 miles of 42-inch diameter pipeline commencing from the terminus of the Rockies Express-West pipeline in Audrain County, Missouri to a terminus near the town of

Clarington in Monroe County, Ohio. The pipeline segment will be capable of transporting approximately 1.8 billion cubic feet per day of natural gas. The FERC issued a draft environmental report in late November 2007 for the REX-East Project, and subject to receipt of regulatory approvals, the REX-East Project is expected to begin partial service on December 31, 2008, and to be in full service in June 2009.

In December 2007, Rockies Express Pipeline LLC completed a non-binding open season undertaken to solicit market interest for the "Northeast Express Project," a 375-mile extension and expansion of the Rockies Express pipeline system from Clarington, Ohio, to Princeton, New Jersey. Significant expressions of interest were received on the Northeast Express Project and negotiations with prospective shippers to enter into binding commitments are currently underway. Subject to receipt of sufficient binding commitments and regulatory approvals, the Northeast Express Project would go into service in late 2010. When complete, the Northeast Express Project would provide up to 1.8 billion cubic feet of transportation capacity to northeast markets from the Lebanon Hub and other pipeline receipt points between Lebanon, Ohio and Clarington, Ohio.

Markets. The Rockies Express Pipeline is capable of delivering gas to multiple markets along its pipeline system, primarily through interconnects with other interstate pipeline companies and direct connects to local distribution companies. Rockies Express Pipeline's Zone 1 encompasses receipts and deliveries of natural gas west of the Cheyenne Hub, located in Northern Colorado near Cheyenne, Wyoming. Through the Zone 1 facilities, Rockies Express can deliver gas to TransColorado Gas Transmission Company LLC in northwestern Colorado, which can in turn transport the gas further south for delivery into the San Juan Basin area. In Zone 1, Rockies Express Pipeline can also deliver gas into western Wyoming through leased capacity on the Overthrust Pipeline Company system, or through its interconnections with Colorado Interstate Gas Company and Wyoming Interstate Company in southern Wyoming. REX-West has the ability to deliver natural gas to points at the Cheyenne Hub, which could be used in markets along the Front Range of Colorado, or could be transported further east through either Rockies Express Pipeline's Zone 2 facilities or other pipeline systems.

Rockies Express Pipeline's Zone 2 extends from the Cheyenne Hub to an interconnect with the Panhandle Eastern Pipeline in Audrain County, Missouri. Through the Zone 2 facilities, Rockies Express facilitates the delivery of natural gas into the Midcontinent area of the Unites States through various interconnects with other major interstate pipelines in Nebraska (Northern Natural Gas Pipeline and NGPL), Kansas (ANR Pipeline), and Missouri (Panhandle Eastern Pipeline). Rockies Express Pipeline's transportation capacity under interim service is currently 1.4 billion cubic feet per day, and when this system is placed into full service it will be capable of delivering 1.5 billion cubic feet per day through these interconnects to the Midcontinent market.

Supply. Rockies Express Pipeline directly accesses major gas supply basins in western Colorado and western Wyoming. In western Colorado, Rockies Express Pipeline has access to gas supply from the Uinta and Piceance basins in eastern Utah and western Colorado. In western Wyoming, Rockies Express Pipeline accesses the Green River Basin through its facilities that are leased from Overthrust. With its connections to numerous other pipeline systems along its route, Rockies Express Pipeline has access to almost all of the major gas supply basins in Wyoming, Colorado and eastern Utah.

Competition. Although there are some competitors to the Rockies Express Pipeline system that provide a similar service, there are none that can compete with the economy-of-scale that Rockies Express Pipeline provides to its shippers to transport gas from the Rocky Mountain region to the Midcontinent markets. The REX-East Project, noted above, will put the Rockies Express Pipeline system in a very unique position of being the only pipeline capable of offering a large volume of transportation service from Rocky Mountain gas supply directly to customers in Ohio.

Rockies Express Pipeline could also experience competition for its Rocky Mountain gas supply from both existing and proposed systems. Questar Pipeline Company accesses many of the same basins as Rockies Express Pipeline and transports gas to its markets in Utah and to other interconnects, which have access to the California market. In addition, there are pipelines that are proposed to use Rocky Mountain gas to supply markets on the West Coast.

Kinder Morgan Louisiana Pipeline

In September 2006, we filed an application with the FERC requesting approval to construct and operate our Kinder Morgan Louisiana Pipeline. The natural gas pipeline project is expected to cost approximately $510 million and will provide approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal located in Cameron Parish, Louisiana. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total.

The Kinder Morgan Louisiana Pipeline will consist of two segments:

- a 132-mile, 42-inch diameter pipeline with firm capacity of approximately 2.0 billion cubic feet per day of natural gas that will extend from the Sabine Pass terminal to a point of interconnection with an existing Columbia Gulf Transmission line in Evangeline Parish, Louisiana (an offshoot will consist of approximately 2.3 miles of 24-inch diameter pipeline with firm peak day capacity of approximately 300 million cubic feet per day extending away from the 42-inch diameter line to the existing Florida Gas Transmission Company compressor station in Acadia Parish, Louisiana). This segment is expected to be in service by January 1, 2009; and
- a 1-mile, 36-inch diameter pipeline with firm capacity of approximately 1.2 billion cubic feet per day that will extend from the Sabine Pass terminal and connect to NGPL's natural gas pipeline. This portion of the project is expected to be in service in the third quarter of 2008.

We have designed and will construct the Kinder Morgan Louisiana Pipeline in a manner that will minimize environmental impacts, and where possible, existing pipeline corridors will be used to minimize impacts to communities and to the environment. As of December 31, 2007, there were no major pipeline re-routes as a result of any landowner requests.

Midcontinent Express Pipeline LLC

On October 9, 2007, Midcontinent Express Pipeline LLC filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the approximate 500-mile Midcontinent Express Pipeline natural gas transmission system. We currently own a 50% interest in Midcontinent Express Pipeline LLC and we account for our investment under the equity method of accounting. Energy Transfer Partners, L.P. owns the remaining 50% interest. The Midcontinent Express Pipeline will create long-haul, firm natural gas transportation takeaway capacity, either directly or indirectly, from natural gas producing regions located in Texas, Oklahoma and Arkansas. The total project is expected to cost approximately $1.3 billion, and will have an initial transportation capacity of approximately 1.4 billion cubic feet per day of natural gas.

For additional information regarding the Midcontinent Express Pipeline, see "(a) General Development of Business—Recent Developments."

Casper and Douglas Natural Gas Processing Systems

We own and operate our Casper and Douglas, Wyoming natural gas processing plants, which have the capacity to process up to 185 million cubic feet per day of natural gas depending on raw gas quality.

Markets. Casper and Douglas are processing plants servicing gas streams flowing into KMIGT. Natural gas liquids processed by our Casper plant are sold into local markets consisting primarily of retail propane dealers and oil refiners. Natural gas liquids processed by our Douglas plant are sold to ConocoPhillips via their Powder River natural gas liquids pipeline for either ultimate consumption at the Borger refinery or for further disposition to the natural gas liquids trading hubs located in Conway, Kansas and Mont Belvieu, Texas.

Competition. Other regional facilities in the Greater Powder River Basin include the Hilight plant (80 million cubic feet per day) owned and operated by Anadarko, the Sage Creek plant (50 million cubic feet per day) owned and operated by Merit Energy, and the Rawlins plant (230 million cubic feet per day) owned and operated by El

Paso. Casper and Douglas, however, are the only plants which provide straddle processing of natural gas flowing into KMIGT.

Red Cedar Gathering Company

We own a 49% equity interest in the Red Cedar Gathering Company, a joint venture organized in August 1994 and referred to in this report as Red Cedar. The remaining 51% interest in Red Cedar is owned by the Southern Ute Indian Tribe. Red Cedar owns and operates natural gas gathering, compression and treating facilities in the Ignacio Blanco Field in La Plata County, Colorado. The Ignacio Blanco Field lies within the Colorado portion of the San Juan Basin, most of which is located within the exterior boundaries of the Southern Ute Indian Tribe Reservation. Red Cedar gathers coal seam and conventional natural gas at wellheads and several central delivery points, for treating, compression and delivery into any one of four major interstate natural gas pipeline systems and an intrastate pipeline.

Red Cedar also owns Coyote Gas Treating, LLC, referred to in this report as Coyote Gulch. The sole asset owned by Coyote Gulch is a 250 million cubic feet per day natural gas treating facility located in La Plata County, Colorado. The inlet gas stream treated by Coyote Gulch contains an average carbon dioxide content of between 12% and 13%. The plant treats the gas down to a carbon dioxide concentration of 2% in order to meet interstate natural gas pipeline quality specifications, and then compresses the natural gas into the TransColorado Gas Transmission pipeline for transport to the Blanco, New Mexico-San Juan Basin Hub.

Red Cedar's gas gathering system currently consists of over 1,100 miles of gathering pipeline connecting more than 920 producing wells, 85,000 horsepower of compression at 24 field compressor stations and two carbon dioxide treating plants. The capacity and throughput of the Red Cedar system as currently configured is approximately 750 million cubic feet per day of natural gas.

Thunder Creek Gas Services, LLC

We own a 25% equity interest in Thunder Creek Gas Services, LLC, referred to in this report as Thunder Creek. Devon Energy owns the remaining 75%. Thunder Creek provides gathering, compression and treating services to a number of coal seam gas producers in the Powder River Basin of Wyoming. Throughput volumes include both coal seam and conventional plant residue gas.

Thunder Creek's operations are a combination of mainline and low pressure gathering assets. The mainline assets include 125 miles of mainline pipeline, 230 miles of high and low pressure laterals, 26,635 horsepower of mainline compression and carbon dioxide removal facilities consisting of a 220 million cubic feet per day carbon dioxide treating plant complete with dehydration. The mainline assets receive gas from 53 receipt points and can deliver treated gas to seven delivery points including Colorado Interstate Gas, Wyoming Interstate Gas Company, KMIGT and three power plants. The low pressure gathering assets include five systems consisting of 194 miles of gathering pipeline and 35,329 horsepower of field compression.

CO_2

Our CO_2 segment consists of Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates, referred to in this report as $KMCO_2$. Carbon dioxide is used in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our carbon dioxide pipelines and related assets allow us to market a complete package of carbon dioxide supply, transportation and technical expertise to the customer. Together, our CO_2 business segment produces, transports and markets carbon dioxide for use in enhanced oil recovery operations. We also hold ownership interests in several oil-producing fields and own a 450-mile crude oil pipeline, all located in the Permian Basin region of West Texas.

Carbon Dioxide Reserves

We own approximately 45% of, and operate, the McElmo Dome unit in Colorado, which contains more than nine trillion cubic feet of recoverable carbon dioxide. Deliverability and compression capacity exceeds one billion cubic feet per day. We are currently installing facilities and drilling 8 wells to increase the production capacity from

McElmo Dome by approximately 200 million cubic feet per day. We also own approximately 11% of the Bravo Dome unit in New Mexico, which contains more than one trillion cubic feet of recoverable carbon dioxide and produces approximately 290 million cubic feet per day.

We also own approximately 88% of the Doe Canyon Deep unit in Colorado, which contains more than 1.5 trillion cubic feet of carbon dioxide. We have installed facilities and drilled six wells to produce approximately 100 million cubic feet per day of carbon dioxide beginning in January 2008.

Markets. Our principal market for carbon dioxide is for injection into mature oil fields in the Permian Basin, where industry demand is expected to grow modestly for the next several years. We are exploring additional potential markets, including enhanced oil recovery targets in California, Wyoming, the Gulf Coast, Mexico, and Canada, and coal bed methane production in the San Juan Basin of New Mexico.

Competition. Our primary competitors for the sale of carbon dioxide include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain carbon dioxide reserves, and Petro-Source Carbon Company, which gathers waste carbon dioxide from natural gas production in the Val Verde Basin of West Texas. There is no assurance that new carbon dioxide sources will not be discovered or developed, which could compete with us or that new methodologies for enhanced oil recovery will not replace carbon dioxide flooding.

Carbon Dioxide Pipelines

As a result of our 50% ownership interest in Cortez Pipeline Company, we own a 50% equity interest in and operate the approximate 500-mile, Cortez pipeline. The pipeline carries carbon dioxide from the McElmo Dome and Doe Canyon source fields near Cortez, Colorado to the Denver City, Texas hub. The Cortez pipeline currently transports over one billion cubic feet of carbon dioxide per day, including approximately 99% of the carbon dioxide transported downstream on our Central Basin pipeline and our Centerline pipeline. The tariffs charged by Cortez Pipeline are not regulated.

Our Central Basin pipeline consists of approximately 143 miles of pipe and 177 miles of lateral supply lines located in the Permian Basin between Denver City, Texas and McCamey, Texas with a throughput capacity of 600 million cubic feet per day. At its origination point in Denver City, our Central Basin pipeline interconnects with all three major carbon dioxide supply pipelines from Colorado and New Mexico, namely the Cortez pipeline (operated by $KMCO_2$) and the Bravo and Sheep Mountain pipelines (operated by Oxy Permian). Central Basin's mainline terminates near McCamey where it interconnects with the Canyon Reef Carriers pipeline and the Pecos pipeline. The tariffs charged by the Central Basin pipeline are not regulated.

Our Centerline pipeline consists of approximately 113 miles of pipe located in the Permian Basin between Denver City, Texas and Snyder, Texas. The pipeline has a capacity of 300 million cubic feet per day. The tariffs charged by the Centerline pipeline are not regulated.

We own a 13% undivided interest in the 218-mile, Bravo pipeline, which delivers CO2 from the Bravo Dome source field in northeast New Mexico to the Denver City hub and has a capacity of more than 350 million cubic feet per day. Tariffs on the Bravo pipeline are not regulated.

In addition, we own approximately 98% of the Canyon Reef Carriers pipeline and approximately 69% of the Pecos pipeline. The Canyon Reef Carriers pipeline extends 139 miles from McCamey, Texas, to the SACROC unit. The pipeline has a capacity of approximately 290 million cubic feet per day and makes deliveries to the SACROC, Sharon Ridge, Cogdell and Reinecke units. The Pecos pipeline is a 25-mile pipeline that runs from McCamey to Iraan, Texas. It has a capacity of approximately 120 million cubic feet per day of carbon dioxide and makes deliveries to the Yates unit. The tariffs charged on the Canyon Reef Carriers and Pecos pipelines are not regulated.

Markets. The principal market for transportation on our carbon dioxide pipelines is to customers, including ourselves, using carbon dioxide for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to grow modestly for the next several years.

Competition. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other carbon dioxide pipelines. We also compete with other interest owners in McElmo Dome and Bravo Dome for transportation of carbon dioxide to the Denver City, Texas market area.

Oil Acreage and Wells

$KMCO_2$ also holds ownership interests in oil-producing fields, including an approximate 97% working interest in the SACROC unit, an approximate 50% working interest in the Yates unit, a 21% net profits interest in the H.T. Boyd unit, an approximate 65% working interest in the Claytonville unit, an approximate 95% working interest in the Katz CB Long unit, an approximate 64% working interest in the Katz SW River unit, a 100% working interest in the Katz East River unit, and lesser interests in the Sharon Ridge unit, the Reinecke unit and the MidCross unit, all of which are located in the Permian Basin of West Texas.

The SACROC unit is one of the largest and oldest oil fields in the United States using carbon dioxide flooding technology. The field is comprised of approximately 56,000 acres located in the Permian Basin in Scurry County, Texas. SACROC was discovered in 1948 and has produced over 1.29 billion barrels of oil since inception. It is estimated that SACROC originally held approximately 2.7 billion barrels of oil. We have expanded the development of the carbon dioxide project initiated by the previous owners and increased production over the last several years. The Yates unit is also one of the largest oil fields ever discovered in the United States. It is estimated that it originally held more than five billion barrels of oil, of which about 29% has been produced. The field, discovered in 1926, is comprised of approximately 26,000 acres located about 90 miles south of Midland, Texas.

As of December 2007, the SACROC unit had 391 producing wells, and the purchased carbon dioxide injection rate was 211 million cubic feet per day, down from an average of 247 million cubic feet per day as of December 2006. The average oil production rate for 2007 was approximately 27,600 barrels of oil per day, down from an average of approximately 30,800 barrels of oil per day during 2006. The average natural gas liquids production rate (net of the processing plant share) for 2007 was approximately 6,300 barrels per day, an increase from an average of approximately 5,700 barrels per day during 2006.

Our plan has been to increase the production rate and ultimate oil recovery from Yates by combining horizontal drilling with carbon dioxide injection to ensure a relatively steady production profile over the next several years. We are implementing our plan and as of December 2007, the Yates unit was producing about 27,600 barrels of oil per day. As of December 2006, the Yates unit was producing approximately 27,200 barrels of oil per day. Unlike our operations at SACROC, where we use carbon dioxide and water to drive oil to the producing wells, we are using carbon dioxide injection to replace nitrogen injection at Yates in order to enhance the gravity drainage process, as well as to maintain reservoir pressure. The differences in geology and reservoir mechanics between the two fields mean that substantially less capital will be needed to develop the reserves at Yates than is required at SACROC.

We also operate and own an approximate 65% gross working interest in the Claytonville oil field unit located in Fisher County, Texas. The Claytonville unit is located nearly 30 miles east of the SACROC unit in the Permian Basin of West Texas and is currently producing approximately 230 barrels of oil per day. We are presently evaluating operating and subsurface technical data from the Claytonville unit to further assess redevelopment opportunities including carbon dioxide flood operations.

We also operate and own working interests in the Katz CB Long unit, the Katz Southwest River unit and Katz East River unit. The Katz field is located in the Permian Basin area of West Texas and, as of December 2007, was producing approximately 400 barrels of oil equivalent per day. We are presently evaluating operating and subsurface technical data to further assess redevelopment opportunities for the Katz field including the potential for carbon dioxide flood operations.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which we own interests as of December 31, 2007. When used with respect to acres or wells, gross refers to the total acres or wells in which we have a working interest; net refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by us:

	Productive Wells (a)		Service Wells (b)		Drilling Wells (c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,463	1,587	1,066	789	2	2
Natural Gas	8	4	—	—	—	—
Total Wells	2,471	1,591	1,066	789	2	2

(a) Includes active wells and wells temporarily shut-in. As of December 31, 2007, we did not operate any productive wells with multiple completions.

(b) Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of saltwater into an underground formation; a service well is a well drilled in a known oil field in order to inject liquids that enhance recovery or dispose of salt water.

(c) Consists of development wells in the process of being drilled as of December 31, 2007.A development well is a well drilled in an already discovered oil field.

The oil and gas producing fields in which we own interests are located in the Permian Basin area of West Texas. The following table reflects our net productive and dry wells that were completed in each of the three years ended December 31, 2007, 2006 and 2005:

	2007	2006	2005
Productive			
Development	31	37	42
Exploratory	—	—	—
Dry			
Development	—	—	—
Exploratory	—	—	—
Total Wells	31	37	42

Notes: The above table includes wells that were completed during each year regardless of the year in which drilling was initiated, and does not include any wells where drilling operations were not completed as of the end of the applicable year. Development wells include wells drilled in the proved area of an oil or gas resevoir.

The following table reflects the developed and undeveloped oil and gas acreage that we held as of December 31, 2007:

	Gross	Net
Developed Acres	72,435	67,731
Undeveloped Acres	8,788	8,129
Total	81,223	75,860

Operating Statistics

Operating statistics from our oil and gas producing activities for each of the years 2007, 2006 and 2005 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2007	**2006**	**2005**
Consolidated Companies(a)			
Production costs per barrel of oil equivalent(b)(c)(d)	$ 16.22	$ 13.30	$ 10.00
Crude oil production (MBbl/d)	35.6	37.8	37.9
Natural gas liquids production (MBbl/d)(d)	5.5	5.0	5.3
Natural gas liquids production from gas plants(MBbl/d)(e)	4.1	3.9	4.1
Total natural gas liquids production(MBbl/d)	9.6	8.9	9.4
Natural gas production (MMcf/d)(d)(f)	0.8	1.3	3.7
Natural gas production from gas plants(MMcf/d)(e)(f)	0.3	0.3	3.1
Total natural gas production(MMcf/d)(f)	1.1	1.6	6.8
Average sales prices including hedge gains/losses:			
Crude oil price per Bbl(g)	$ 36.05	$ 31.42	$ 27.36
Natural gas liquids price per Bbl(g)	$ 52.22	$ 43.52	$ 38.79
Natural gas price per Mcf(h)	$ 6.08	$ 6.36	$ 5.84
Total natural gas liquids price per Bbl(e)	$ 52.91	$ 43.90	$ 38.98
Total natural gas price per Mcf(e)	$ 5.89	$ 7.02	$ 5.80
Average sales prices excluding hedge gains/losses:			
Crude oil price per Bbl(g)	$ 69.63	$ 63.27	$ 54.45
Natural gas liquids price per Bbl(g)	$ 52.22	$ 43.52	$ 38.79
Natural gas price per Mcf(h)	$ 6.08	$ 6.36	$ 5.84

(a) Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidaries.

(b) Computed using production costs, excluding transportation costs, as defined by the United States Securities and Exchange Commisson. Natural gas volumes were converted to barrels of oil equivalent (BOE) using a conversion factor of six mcf of natural gas to one barrel of oil.

(c) Production costs include labor, repairs and maintenance, materials, supplies, fuel and power, property taxes, severance taxes, and general and administrative expenses directly related to oil and gas producing activities.

(d) Includes only production attributable to leasehold ownership.

(e) Includes production attributable to our ownership in processing plants and third party processing agreements.

(f) Excludes natural gas production used as fuel.

(g) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

(h) Natural gas sales were not hedged.

See Note 20 to our consolidated financial statements included in this report for additional information with respect to operating statistics and supplemental information on our oil and gas producing activities.

Gas and Gasoline Plant Interests

We operate and own an approximate 22% working interest plus an additional 28% net profits interest in the Snyder gasoline plant. We also operate and own a 51% ownership interest in the Diamond M gas plant and a 100% ownership interest in the North Snyder plant, all of which are located in the Permian Basin of West Texas. The Snyder gasoline plant processes gas produced from the SACROC unit and neighboring carbon dioxide projects, specifically the Sharon Ridge and Cogdell units, all of which are located in the Permian Basin area of West Texas. The Diamond M and the North Snyder plants contract with the Snyder plant to process gas. Production of natural gas liquids at the Snyder gasoline plant as of December 2007 was approximately 15,500 barrels per day as compared to 15,000 barrels per day as of December 2006.

Crude Oil Pipeline

We own our Kinder Morgan Wink Pipeline, a 450-mile Texas intrastate crude oil pipeline system consisting of three mainline sections, two gathering systems and numerous truck delivery stations. The segment that runs from Wink to El Paso has a total capacity of 130,000 barrels of crude oil per day. The pipeline allows us to better manage crude oil deliveries from our oil field interests in West Texas, and we have entered into a long-term throughput agreement with Western Refining Company, L.P. to transport crude oil into Western's 120,000 barrel per day refinery in El Paso. The 20-inch pipeline segment transported approximately119,000 barrels of oil per day in 2007. The Kinder Morgan Wink Pipeline is regulated by both the FERC and the Texas Railroad Commission.

Terminals

Our Terminals segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment) and all of our coal, petroleum coke, fertilizer, steel, ores and dry-bulk material services, including all transload, engineering, conveying and other in-plant services. Combined, the segment is composed of approximately100 owned or operated liquids and bulk terminal facilities, and more than 45 rail transloading and materials handling facilities located throughout the United States, Canada and the Netherlands. In 2007, the number of customers from whom our Terminals segment received more than $0.1 million of revenue was approximately 650.

Liquids Terminals

Our liquids terminals operations primarily store refined petroleum products, petrochemicals, industrial chemicals and vegetable oil products in aboveground storage tanks and transfer products to and from pipelines, vessels, tank trucks, tank barges, and tank railcars. Combined, our liquids terminals facilities possess liquids storage capacity of approximately 47.5 million barrels, and in 2007, these terminals handled approximately 557 million barrels of petroleum, chemicals and vegetable oil products.

In September 2006, we announced major expansions at our Pasadena and Galena Park, Texas terminal facilities. The expansions will provide additional infrastructure to help meet the growing need for refined petroleum products storage capacity along the Gulf Coast. The investment of approximately $195 million includes the construction of the following: (i) new storage tanks at both our Pasadena and Galena Park terminals; (ii) an additional cross-channel pipeline to increase the connectivity between the two terminals; (iii) a new ship dock at Galena Park; and (iv) an additional loading bay at our fully automated truck loading rack located at our Pasadena terminal. The expansions are supported by long-term customer commitments and will result in approximately 3.4 million barrels of additional tank storage capacity at the two terminals. Construction began in October 2006, and all of the projects are expected to be completed by the spring of 2008, with the exception of the of the Galena Park ship dock which is now scheduled to be in-service by the third quarter of 2008.

At Perth Amboy, New Jersey, we completed construction and placed into service nine new storage tanks with a capacity of 1.4 million barrels for gasoline, diesel and jet fuel. These tanks have been leased on a long-term basis to two customers. Our total investment in these facilities was approximately $69 million.

In June 2006, we announced the construction of a new crude oil tank farm located in Edmonton, Alberta, Canada, and long-term contracts with customers for all of the available capacity at the facility. Situated on approximately 24 acres, the new storage facility will have nine tanks with a combined storage capacity of approximately 2.2 million barrels for crude oil. Service is expected to begin in the first quarter of 2008, and when completed, the tank farm will serve as a premier blending and storage hub for Canadian crude oil. Originally estimated at $115 million, due primarily to additional labor costs, total investment in this tank farm is projected to be $162 million on a constant U.S. dollar basis. The tank farm will have access to more than 20 incoming pipelines and several major outbound systems, including a connection with our Trans Mountain pipeline system, which currently transports up to 260,000 barrels per day of heavy crude oil and refined products from Edmonton to marketing terminals and refineries located in the greater Vancouver, British Columbia area and Puget Sound in Washington state.

Competition . We are one of the largest independent operators of liquids terminals in North America. Our primary competitors are IMTT, Magellan, Morgan Stanley, NuStar, Oil Tanking, Teppco, and Vopak.

Bulk Terminals

Our bulk terminal operations primarily involve dry-bulk material handling services; however, we also provide conveyor manufacturing and installation, engineering and design services and in-plant services covering material handling, conveying, maintenance and repair, railcar switching and miscellaneous marine services. Combined, our dry-bulk and material transloading facilities handled approximately 87.1 million tons of coal, petroleum coke, fertilizers, steel, ores and other dry-bulk materials in 2007. We own or operate approximately 93 dry-bulk terminals in the United States, Canada and the Netherlands.

In May 2007, we purchased certain buildings and equipment and completed a 40 year agreement to operate Vancouver Wharves, a bulk marine terminal located at the entrance to the Port of Vancouver, British Columbia. The facility consists of five vessel berths situated on a 139-acre site, extensive rail infrastructure, dry-bulk and liquid storage, and material handling systems, which allow the terminal to handle over 3.5 million tons of cargo annually. Vancouver Wharves has access to three major rail carriers connecting to shippers in western and central Canada and the U.S. Pacific Northwest. Vancouver Wharves offers a variety of inbound, outbound and value-added services for mineral concentrates, wood products, agri-products and sulfur. In addition to the aggregate consideration of approximately $57.2 million ($38.8 million in cash and the assumption of $18.4 million of assumed liabilities) paid for this facility, we plan to invest an additional $46 million at Vancouver Wharves over the next two years to upgrade and relocate certain rail track and transloading systems, buildings and a shiploader.

Effective September 1, 2007, we purchased the assets of Marine Terminals, Inc. for an aggregate consideration of approximately $101.5 million. Combined, the assets handle approximately 13.5 million tons of alloys and steel products annually from five facilities located in the southeast United States. These strategically located terminals provide handling, processing, harboring and warehousing services primarily to Nucor Corporation, one of the largest steel and steel products companies in the world, under long-term contracts.

Competition . Our bulk terminals compete with numerous independent terminal operators, other terminals owned by oil companies, stevedoring companies, and other industrials opting not to outsource terminal services. Many of our bulk terminals were constructed pursuant to long-term contracts for specific customers. As a result, we believe other terminal operators would face a significant disadvantage in competing for this business.

Materials Services (rail transloading)

Our materials services operations include rail or truck transloading operations conducted at 45 owned and non-owned facilities. The Burlington Northern Santa Fe, CSX, Norfolk Southern, Union Pacific, Kansas City Southern and A&W railroads provide rail service for these terminal facilities. Approximately 50% of the products handled are liquids, including an entire spectrum of liquid chemicals, and 50% are dry-bulk products. Many of the facilities are equipped for bi-modal operation (rail-to-truck, and truck-to-rail) or connect via pipeline to storage facilities. Several facilities provide railcar storage services. We also design and build transloading facilities, perform inventory management services, and provide value-added services such as blending, heating and sparging. In 2007, our materials services operations handled approximately 347,000 railcars.

Competition Our material services operations compete with a variety of national transload and terminal operators across the United States, including Savage Services, Watco and Bulk Plus Logistics. Additionally, single or multi-site terminal operators are often entrenched in the network of Class 1 rail carriers.

Trans Mountain

Our Trans Mountain common carrier pipeline system originates at Edmonton, Alberta and transports crude oil and refined petroleum to destinations in the interior and on the west coast of British Columbia. A connecting pipeline owned by us delivers petroleum to refineries in the state of Washington.

Trans Mountain's pipeline is 715 miles. The capacity of the line out of Edmonton ranges from 260,000 barrels per day when heavy crude represents 20% of the total throughput to 300,000 barrels per day with no heavy crude. The pipeline system utilizes 21 pump stations controlled by a centralized computer control system.

Trans Mountain also operates a 5.3 mile spur line from its Sumas Pump Station to the U.S. – Canada international border where it connects with a 63 mile pipeline system owned and operated by us. The pipeline system in Washington State has a sustainable throughput capacity of approximately 135,000 barrels per day when heavy crude represents approximately 25% of throughput and connects to four refineries located in northwestern Washington State. The volumes of petroleum shipped to Washington State fluctuate in response to the price levels of Canadian crude oil in relation to petroleum produced in Alaska and other offshore sources.

In 2007, deliveries on Trans Mountain averaged 258,540 barrels per day. This was an increase of 13% from average 2006 deliveries of 229,369 barrels per day. In April 2007, we commissioned ten new pump stations that boosted capacity on Trans Mountain from 225,000 to approximately 260,000 barrels per day. The crude oil and refined petroleum transported through Trans Mountain's pipeline system originates in Alberta and British Columbia. The refined and partially refined petroleum transported to Kamloops, British Columbia and Vancouver originates from oil refineries located in Edmonton. Petroleum products delivered through Trans Mountain's pipeline system are used in markets in British Columbia, Washington State and elsewhere.

Overall Alberta crude oil supply has been increasing steadily over the past few years as a result of significant oilsands development with projects led by Shell Canada, Suncor Energy and Syncrude Canada. Further development is expected to continue into the future with expansions to existing oilsands production facilities as well as with new projects. In its moderate growth case, the Canadian Association of Petroleum Producers ("CAPP") forecasts Western Canadian crude oil production to increase by over 1.6 million barrels per day by 2015. This increasing supply will likely result in constrained export pipeline capacity from Western Canada, which supports Trans Mountain's view that both the demand for transportation services provided by Trans Mountain's pipeline and the supply of crude oil will remain strong for the foreseeable future.

Shipments of refined petroleum represent a significant portion of Trans Mountain's throughput. In 2007, shipments of refined petroleum and iso-octane represented 25% of throughput, as compared with 28% in 2006.

Major Customers

Our total operating revenues are derived from a wide customer base.For each of the years ended December 31, 2007, 2006 and 2005, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. Our Texas intrastate natural gas pipeline group buys and sells significant volumes of natural gas within the state of Texas and, to a far lesser extent, our CO2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from our Natural Gas Pipelines and CO2 business segments in 2007, 2006 and 2005 accounted for 63.3%, 66.8% and 73.9%, respectively, of our total consolidated revenues.

As a result of our Texas intrastate group selling natural gas in the same price environment in which it is purchased, both our total consolidated revenues and our total consolidated purchases (cost of sales) increase considerably due to the inclusion of the cost of gas in both financial statement line items. However, these higher revenues and higher purchased gas costs do not necessarily translate into increased margins in comparison to those situations in which we charge a fee to transport gas owned by others as we seek to match the purchase and sales indexes and lock in a transport fee. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Regulation

Interstate Common Carrier Pipeline Rate Regulation – U.S. Operations

Some of our pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC, which tariffs set forth the rates we charge for providing transportation services on our interstate common carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common carrier pipelines be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the

Hedging effectiveness and ineffectiveness

Our interest rate swap contracts have been designated as fair value hedges and meet the conditions required to assume no ineffectiveness under SFAS No. 133. Therefore, we have accounted for them using the "shortcut" method prescribed by SFAS No. 133 and accordingly, we adjust the carrying value of each swap contract to its fair value each quarter, with an offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged. We record interest expense equal to the variable rate payments under the swap contracts.

Fair Value of Interest Rate Swap Agreements

The fair values of our interest rate swap agreements are included within "Deferred charges and other assets" and "Other long-term liabilities and deferred credits" in our accompanying consolidated balance sheets. The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within "Value of interest rate swaps" on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of December 31, 2007, this unamortized premium totaled $14.2 million, representing the unamortized proceeds we received from the swap agreement we terminated in the first quarter of 2007.

The following table summarizes the net fair value of our interest rate swap agreements associated with our interest rate risk management activities and included on our accompanying consolidated balance sheets as of December 31, 2007 and December 31, 2006 (in millions):

	December 31, 2007	December 31, 2006
Derivatives-net asset/(liability)		
Deferred charges and other assets	$ 138.0	$ 65.2
Other long-term liabilities and deferred credits		(22.6)
Net fair value of interest rate swaps	$ 138.0	$ 42.6

Furthermore, we are exposed to credit related losses in the event of nonperformance by counterparties to our interest rate swap agreements, and while we enter into derivative contracts primarily with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk. As of December 31, 2007, all of our interest rate swap agreements were with counterparties with investment grade credit ratings.

Other

Certain of our business activities expose us to foreign currency fluctuations. However, due to the limited size of this exposure, we do not believe the risks associated with changes in foreign currency will have a material adverse effect on our business, financial position, results of operations or cash flows. As a result, we do not significantly hedge our exposure to fluctuations in foreign currency.

15. Reportable Segments

We divide our operations into five reportable business segments:

- Products Pipelines;
- Natural Gas Pipelines;
- CO_2;
- Terminals; and
- Trans Mountain.

Each segment uses the same accounting policies as those described in the summary of significant accounting policies (see Note 2). We evaluate performance principally based on each segments' earnings before depreciation, depletion and amortization, which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income and income tax expense, and minority interest. Our reportable segments are strategic business units that offer different products and services. Each segment is managed separately because each segment involves different products and marketing strategies.

Our Products Pipelines segment derives its revenues primarily from the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids. Our Natural Gas Pipelines segment derives its revenues primarily from the sale, transport, processing, treating, storage and gathering of natural gas. Our CO_2 segment derives its revenues primarily from the production and sale of crude oil from fields in the Permian Basin of West Texas and from the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields. Our Terminals segment derives its revenues primarily from the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals. Our Trans Mountain business segment derives its revenues primarily from the transportation of crude oil and refined products from Edmonton, Alberta to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State.

As discussed in Note 3, due to the sale of our North System, an approximate 1,600-mile interstate common carrier pipeline system whose operating results were included as part of our Products Pipelines business segment, we accounted for the North System business as a discontinued operation. Consistent with the management approach of identifying and reporting discrete financial information on operating segments, we have included the North System's financial results within our Products Pipelines business segment disclosures for all periods presented in this report and, as prescribed by SFAS No. 131, we have reconciled the total of our reportable segment's financial results to our consolidated financial results by separately identifying, in the following pages where applicable, the North System amounts as discontinued operations.

Financial information by segment follows (in millions):

	2007	2006	2005
Revenues			
Products Pipelines			
Revenues from external customers	$ 844.4	$ 776.3	$ 711.8
Intersegment revenues	—	—	—
Natural Gas Pipelines			
Revenues from external customers	6,466.5	6,577.7	7,718.4
Intersegment revenues	—	—	—
CO_2			
Revenues from external customers	824.1	736.5	657.6
Intersegment revenues	—	—	—
Terminals			
Revenues from external customers	963.0	864.1	699.3
Intersegment revenues	0.7	0.7	—
Trans Mountain			
Revenues from external customers	160.8	137.8	—
Intersegment revenues	—	—	—
Total segment revenues	9,259.5	9,093.1	9,787.1
Less: Total intersegment revenues	(0.7)	(0.7)	—
	9,258.8	9,092.4	9,787.1
Less: Discontinued operations	(41.1)	(43.7)	(41.2)
Total consolidated revenues	$ 9,217.7	$ 9,048.7	$ 9,745.9

	2007	2006	2005
Operating expenses(a)			
Products Pipelines	$ 451.8	$ 308.3	$ 366.0
Natural Gas Pipelines	5,882.9	6,057.8	7,255.0
CO_2	304.2	268.1	212.6
Terminals	536.4	461.9	373.4
Trans Mountain	65.9	53.3	—
Total segment operating expenses	7,241.2	7,149.4	8,207.0
Less: Total intersegment operating expenses	(0.7)	(0.7)	—
	7,240.5	7,148.7	8,207.0
Less: Discontinued operations	(14.8)	(22.7)	(35.2)
Total consolidated operating expenses	$ 7,225.7	$ 7,126.0	$ 8,171.8
Other expense (income)			
Products Pipelines	$ (154.8)	$ —	$ —
Natural Gas Pipelines	(3.2)	(15.1)	—
CO_2			
Terminals	(6.3)	(15.2)	—
Trans Mountain(b)	377.1	(0.9)	—
Total segment Other expense (income)	212.8	(31.2)	—
Less: Discontinued operations	152.8		
Total consolidated Other expense (income)	$ 365.6	$ (31.2)	$ —
Depreciation, depletion and amortization			
Products Pipelines	$ 89.2	$ 82.9	$ 79.1
Natural Gas Pipelines	64.8	65.4	61.7
CO_2	282.2	190.9	149.9
Terminals	89.3	74.6	59.1
Trans Mountain	21.5	19.0	—
Total segment depreciation, depletion and amortiz.	547.0	432.8	349.8
Less: Discontinued operations	(7.0)	(8.9)	(8.2)
Total consol. depreciation, depletion and amortiz.	$ 540.0	$ 423.9	$ 341.6
Earnings from equity investments			
Products Pipelines	$ 32.5	$ 16.3	$ 28.5
Natural Gas Pipelines	19.2	40.5	36.8
CO_2	19.2	19.2	26.3
Terminals	0.6	0.2	0.1
Trans Mountain	—	—	—
Total segment earnings from equity investments	71.5	76.2	91.7
Less: Discontinued operations	(1.8)	(2.2)	(2.1)
Total consolidated equity earnings	$ 69.7	$ 74.0	$ 89.6
Amortization of excess cost of equity investments			
Products Pipelines	$ 3.4	$ 3.4	$ 3.4
Natural Gas Pipelines	0.4	0.3	0.2
CO_2	2.0	2.0	2.0
Terminals	—	—	—
Trans Mountain	—	—	—
Total segment amortization of excess cost of invests.	5.8	5.7	5.6
Less: Discontinued operations	—	(0.1)	(0.1)

Total consol. amortization of excess cost of invests.	$ 5.8	$ 5.6	$ 5.5
Interest income			
Products Pipelines	$ 4.4	$ 4.5	$ 4.6
Natural Gas Pipelines	—	0.1	0.7
CO_2	—	—	—
Terminals	—	—	—
Trans Mountain	—	—	—
Total segment interest income	4.4	4.6	5.3
Unallocated interest income	1.3	3.1	4.1
Total consolidated interest income	$ 5.7	$ 7.7	$ 9.4

	2007	2006	2005
Other, net-income (expense)			
Products Pipelines	$ 5.0	$ 7.6	$ 1.5
Natural Gas Pipelines	0.2	0.6	2.0
CO_2	—	0.8	—
Terminals	1.0	2.1	(0.2)
Trans Mountain	8.0	1.0	—
Total segment other, net-income (expense)	14.2	12.1	3.3
Less: Discontinued operations	—	(0.1)	—
Total consolidated other, net-income (expense)	$ 14.2	$ 12.0	$ 3.3
Income tax benefit (expense)			
Products Pipelines	$ (19.7)	$ (5.2)	$ (10.3)
Natural Gas Pipelines	(6.0)	(1.4)	(2.6)
CO_2	(2.1)	(0.2)	(0.4)
Terminals	(19.2)	(12.3)	(11.2)
Trans Mountain	(19.4)	(9.9)	—
Total segment income tax benefit (expense)	(66.4)	(29.0)	(24.5)
Unallocated income tax benefit (expense)	(4.6)	—	—
Total consolidated income tax benefit (expense)	$ (71.0)	$ (29.0)	$ (24.5)
Segment earnings(c)			
Products Pipelines	$ 477.0	$ 404.9	$ 287.6
Natural Gas Pipelines	535.0	509.1	438.4
CO_2	252.8	295.3	319.0
Terminals	326.7	333.5	255.5
Trans Mountain	(315.1)	57.5	—
Total segment earnings	1,276.4	1,600.3	1,300.5
Interest and corporate administrative expenses(d)	(686.1)	(596.2)	(488.3)
Total consolidated net income	$ 590.3	$ 1,004.1	$ 812.2
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(e)			
Products Pipelines	$ 569.6	$ 491.2	$ 370.1
Natural Gas Pipelines	600.2	574.8	500.3
CO_2	537.0	488.2	470.9
Terminals	416.0	408.1	314.6
Trans Mountain	(293.6)	76.5	—
Total segment earnings before DD&A	1,829.2	2,038.8	1,655.9
Total segment depreciation, depletion and amortiz.	(547.0)	(432.8)	(349.8)
Total segment amortization of excess cost of invests.	(5.8)	(5.7)	(5.6)
Interest and corporate administrative expenses	(686.1)	(596.2)	(488.3)
Total consolidated net income	$ 590.3	$ 1,004.1	$ 812.2
Capital expenditures(f)			
Products Pipelines	$ 259.4	$ 196.0	$ 271.5
Natural Gas Pipelines	264.0	271.6	102.9
CO_2	382.5	283.0	302.1
Terminals	480.0	307.7	186.6
Trans Mountain	305.7	123.8	—
Total consolidated capital expenditures	$ 1,691.6	$ 1,182.1	$ 863.1

Investments at December 31			
Products Pipelines	$ 202.3	$ 211.1	$ 223.7
Natural Gas Pipelines	427.5	197.9	177.1
CO_2	14.2	16.1	17.9
Terminals	10.6	0.5	0.6
Trans Mountain	0.8	0.7	—
Total consolidated investments	$ 655.4	$ 426.3	$ 419.3

	2007	2006	2005
Assets at December 31			
Products Pipelines	$ 4,045.0	$ 3,910.5	$ 3,873.9
Natural Gas Pipelines	4,347.3	3,946.6	4,140.0
CO_2	2,004.5	1,870.8	1,772.8
Terminals	3,036.4	2,397.5	2,052.5
Trans Mountain	1,440.8	1,314.0	—
Total segment assets	14,874.0	13,439.4	11,839.2
Corporate assets(g)	303.8	102.8	84.3
Total consolidated assets	$ 15,177.8	$ 13,542.2	$ 11,923.5

(a) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, fuel and power expenses and taxes, other than income taxes.

(b) 2007 amount represents an expense of $377.1 million attributable to a goodwill impairment charge recognized by Knight, as discussed in Notes 3 and 8.

(c) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, other expense (income), depreciation, depletion and amortization, and amortization of excess cost of equity investments.

(d) Includes unallocated interest income and income tax expense, interest and debt expense, general and administrative expenses, and minority interest expense.

(e) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).

(f) Includes sustaining capital expenditures of $152.6 million in 2007 (not including Trans Mountain for periods prior to our acquisition date of April 30, 2007), $125.5 million in 2006 (not including Trans Mountain) and $140.8 million in 2005. Sustaining capital expenditures are defined as capital expenditures which do not increase the capacity of an asset.

(g) Includes cash and cash equivalents, margin and restricted deposits, certain unallocable deferred charges, and risk management assets related to the fair value of interest rate swaps.

We do not attribute interest and debt expense to any of our reportable business segments. For each of the years ended December 31, 2007, 2006 and 2005, we reported (in millions) total consolidated interest expense of $397.1 million, $345.5 million and $268.4 million, respectively.

Our total operating revenues are derived from a wide customer base. For each of the three years ended December 31, 2007, 2006 and 2005, no revenues from transactions with a single external customer amounted to 10% or more of our total consolidated revenues.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	2007	2006	2005
Revenues from external customers			
United States	$ 8,986.3	$ 8,889.9	$ 9,715.1
Canada	211.9	139.3	11.8
Mexico and other(a)	19.5	19.5	19.0
Total consol. revenues from external customers	$ 9,217.7	$ 9,048.7	$ 9,745.9
Long-lived assets at December 31(b)			
United States	$ 11,054.3	$ 9,917.2	$ 9,442.8
Canada	1,420.0	766.4	48.2
Mexico and other	89.5	91.4	92.3
Total consolidated long-lived assets	$ 12,563.8	$ 10,775.0	$ 9,583.3

(a) Includes operations in Mexico and the Netherlands.

(b) Long-lived assets exclude (i) goodwill; (ii) other intangibles, net; and (iii) long-term note receivables from related parties.

ONEOK Partners, L.P.
2007 Form 10-K

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007.
OR
__TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______to ______.

Commission file number **1-12202**

ONEOK PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**93-1120873** (I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK (Address of principal executive offices)	**74103-2498** (Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

Securities registered pursuant to Section 12(b) of the Act:

Common units (Title of Each Class)	**New York Stock Exchange** (Name of Each Exchange on which Registered)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No __.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No X.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by checkmark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer X   Accelerated filer __   Non-accelerated filer __

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes __No X.

Aggregate market value of the common units held by non-affiliates based on the closing trade price on June 30, 2007, was $3.2 billion.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 20, 2008
Common units	46,397,214 units
Class B units	36,494,126 units

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PART I

ITEM 1. BUSINESS

GENERAL

ONEOK Partners, L.P. is a publicly traded Delaware limited partnership that was formed in 1993. Our common units are listed on the NYSE under the trading symbol "OKS." We own and manage natural gas gathering, processing, storage and interstate and intrastate pipeline assets and natural gas liquids gathering and distribution pipelines, storage and fractionators, connecting much of the natural gas and NGL supply in the Mid-Continent and Gulf Coast regions with key market centers in Conway, Kansas, Mont Belvieu, Texas, and Chicago, Illinois. We also own a 50 percent equity interest in a leading transporter of natural gas imported from Canada into the United States.

DESCRIPTION OF BUSINESS SEGMENTS

In July 2007, we announced a series of organizational changes that led to the realignment of our previous business segments. Our financial results are now reported in these four segments: (i) Natural Gas Gathering and Processing, which remains unchanged, (ii) Natural Gas Pipelines, which is comprised of our former interstate natural gas pipelines segment and the natural gas assets of our former pipelines and storage segment, (iii) Natural Gas Liquids Gathering and Fractionation, which remains unchanged, and (iv) Natural Gas Liquids Pipelines, which is comprised of the natural gas liquids assets of our former pipelines and storage segment. Prior periods have been restated to reflect these segment changes. The change reflects the increasing scale of the natural gas liquids business, which has grown significantly since 2006. Our natural gas liquids business is expanding as we integrate the assets acquired in October 2007 from a subsidiary of Kinder Morgan Energy Partners, L.P. (Kinder Morgan) into our Natural Gas Liquids Pipelines segment and complete our other internal growth projects.

Our operations are divided into these strategic business segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment, as follows:

- our Natural Gas Gathering and Processing segment primarily gathers and processes raw natural gas;
- our Natural Gas Pipelines segment primarily operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities;
- our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs and stores and markets NGL products; and
- our Natural Gas Liquids Pipelines segment primarily operates our FERC-regulated interstate natural gas liquids gathering and distribution pipelines.

For financial and statistical information regarding our business segments, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation. See Note J of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a discussion of sales to unaffiliated customers, operating income and total assets by business segment.

Partnership Structure

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of six members. Three of our Board members qualify as independent under the listing standards of the NYSE and also serve as the Audit Committee of ONEOK Partners GP. ONEOK Partners GP is a wholly owned subsidiary of ONEOK. ONEOK owns a 45.7 percent aggregate equity interest in us.

Business Strategy

Our primary business objectives are to generate cash flow sufficient to pay quarterly cash distributions to our unitholders and to increase our quarterly cash distributions over time. Our ability to maintain and grow our distributions to unitholders depends on the growth of our existing businesses and strategic acquisitions. We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public.

Our strategy is to expand and acquire assets in the United States related to gathering, processing, fractionating, storing and marketing natural gas and NGLs that will utilize our core competencies, minimize commodity price risk and provide long-

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term, sustainable and stable cash flows. We finance our acquisitions and capital expenditures with a mix of operating cash flows, debt and equity.

In April 2006, we acquired certain companies comprising ONEOK's former gathering and processing, natural gas liquids, and pipeline and storage segments, collectively referred to as the "ONEOK Energy Assets" from ONEOK, the parent company of our general partner, in a series of transactions, collectively referred to as the "ONEOK Transactions," which are described in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures." These assets complemented our core competencies related to energy services and diversified our portfolio of assets. The assets we acquired from ONEOK enabled us to enter into energy-related businesses in the well-established Mid-Continent region and key natural gas liquids markets in Kansas and Texas. In addition, our expanded asset portfolio positions us for future organic growth projects, which we believe currently offer the most attractive growth opportunities for us.

SIGNIFICANT DEVELOPMENTS IN 2007 AND EARLY 2008

In February 2008, we announced plans to construct a 78-mile natural gas liquids gathering pipeline to connect two natural gas processing plants in the Woodford Shale area in southeast Oklahoma at a cost of approximately $25 million, excluding AFUDC. The project is currently scheduled for completion in the second quarter of 2008. These two plants are expected to produce approximately 25 MBbl/d of unfractionated NGLs. Until the Arbuckle Pipeline project is completed, the natural gas liquids production will be transported by our existing Mid-Continent natural gas liquids pipelines. Upon completion of the Arbuckle Pipeline project, the Woodford Shale natural gas liquids production is expected to be transported to our Mont Belvieu, Texas, fractionation facility.

In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL and refined products. The FERC-regulated system spans 1,627 miles and has a capacity to transport up to 134 MBbl/d. The transaction includes approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland.

In September 2007, we completed an underwritten public debt offering of $600 million to finance the assets acquired from Kinder Morgan and to repay outstanding debt under the 2007 Partnership Credit Agreement, which was incurred to fund our internal growth capital projects.

During 2007, we began construction on the Overland Pass Pipeline Company joint-venture project with a subsidiary of The Williams Companies, Inc. (Williams). Overland Pass Pipeline Company is building a 760-mile natural gas liquids pipeline from Opal, Wyoming, to the Mid-Continent natural gas liquids market center in Conway, Kansas. The pipeline is designed to transport approximately 110 MBbl/d of unfractionated NGLs, which can be increased to approximately 150 MBbl/d with additional pump facilities. This project has received the required approvals of various state and federal regulatory authorities, and we are constructing the pipeline with start-up currently scheduled for the second quarter of 2008.

In March 2007, we announced that Overland Pass Pipeline Company also plans to construct a 150-mile lateral pipeline with capacity to transport as much as 100 MBbl/d of unfractionated NGLs from the Piceance Basin in Colorado to the Overland Pass Pipeline. Williams announced that it intends to construct a new natural gas processing plant in the Piceance Basin and will dedicate its NGL production from that plant and an existing plant to be transported by the lateral pipeline. This project requires the approval of various state and federal regulatory authorities. Assuming Overland Pass Pipeline Company obtains the required state and federal regulatory approvals, construction of this lateral pipeline is currently expected to begin in late 2008 and be completed during the second quarter of 2009.

In March 2007, we announced plans to build the 440-mile Arbuckle Pipeline, a natural gas liquids pipeline from southern Oklahoma through northern Texas and continuing on to the Texas Gulf Coast. The Arbuckle Pipeline will have the capacity to transport 160 MBbl/d of unfractionated natural gas liquids and will connect our existing Mid-Continent infrastructure with our fractionation facility in Mont Belvieu, Texas, and other Gulf Coast region fractionators. Construction of the pipeline will require permits from various federal, state and local regulatory bodies. Construction is currently expected to begin in mid-2008 and will be completed by early 2009.

In March 2007, we announced the expansion of our Grasslands natural gas processing facility in North Dakota. The Grasslands facility is our largest natural gas processing plant in the Williston Basin. The expansion increases processing capacity to approximately 100 MMcf/d from its current capacity of 63 MMcf/d and increases fractionation capacity to approximately 12 MBbl/d from 8 MBbl/d. The expansion project is expected to come on-line in phases, with the final phase currently expected to be on-line in the third quarter of 2008.

In January 2007, Fort Union Gas Gathering announced that it will double its existing gathering pipeline capacity by adding 148 miles of new gathering lines and approximately 649 MMcf/d of additional capacity in the Powder River basin of Wyoming. The expansion will occur in two phases. Phase 1 was placed in service during the fourth quarter of 2007. Phase 2 is currently expected to be in service during the second quarter of 2008. We own approximately 37 percent of Fort Union Gas Gathering.

NARRATIVE DESCRIPTION OF BUSINESS

Natural Gas Gathering and Processing

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We pursue growth through additional well connections, system expansions and strategic acquisitions. We seek to restructure expiring contracts to mitigate commodity exposure. We also seek to provide reliable, efficient and consistent operations through optimization of our natural gas gathering and processing operations while managing costs.

Segment Description - Our former gathering and processing segment is now called our Natural Gas Gathering and Processing segment. As part of the ONEOK Transactions described in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures," we acquired all of ONEOK's natural gas gathering and processing assets and combined them with our legacy gathering and processing segment assets in April 2006.

Our operations include gathering of natural gas production from oil and natural gas wells. We gather raw natural gas in the Mid-Continent region, which includes the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas. We also gather raw natural gas in three producing basins in the Rocky Mountain region: (i) the Williston Basin, which spans portions of Montana, North Dakota and the Canadian province of Saskatchewan, (ii) the Powder River Basin of Wyoming and (iii) the Wind River Basin of Wyoming.

Through gathering systems, raw natural gas volumes are aggregated for removal of water vapor, solids and other contaminants and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. When the liquids are separated from the raw natural gas at the processing plants, the liquids are in the form of a mixed, unfractionated NGL stream. This unfractionated NGL stream is generally shipped to fractionators, where by applying heat and pressure, the unfractionated NGL stream is separated into marketable purity products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products can then be stored, transported and marketed to a diverse customer base.

Our Natural Gas Gathering and Processing segment gathers and processes raw natural gas. We generally gather and process gas under the following types of contracts.

- Percent of Proceeds (POP) - Under a POP contract, we retain a percentage of the NGLs and/or a percentage of the residue gas as payment for gathering, compressing and processing the producer's raw natural gas. The producer may take its share of the NGLs and residue gas in kind or receive its share of proceeds from our sale of the commodities. POP contracts expose us to both natural gas and NGL commodity price risk, but economically align us with the producer because we both benefit from higher commodity prices. There are a variety of factors that directly affect our POP margins, including:
  - the percentages of products retained that represent our equity NGL, condensate and residue gas sales volumes,
  - transportation and fractionation costs incurred on the NGLs, and
  - the natural gas, crude oil and NGL prices received for our retained products.
- Fee - Under a fee contract, we are paid a fee for the services provided on a basis such as Btus gathered, compressed and/or processed. The wellhead volume and fees received for the services provided are the main components of the margin for this type of contract. The producer may take its NGLs and residue gas in kind or receive its proceeds from our sale of the commodities. This type of contract primarily exposes us to volumetric risk with minimal commodity price risk, as a result of fuel costs and the value of the retained fuel. Our POP and keep-whole contracts also typically include fee provisions.
- Keep-Whole - Under a keep-whole processing contract, we extract NGLs from the raw natural gas and return to the producer volumes of residue gas containing the same amount of Btus as the raw natural gas that was delivered to us.

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We retain the NGLs as our fee for processing. Accordingly, we must purchase and return to the producer sufficient volumes of residue gas to replace the Btus that were removed as NGLs through the gathering and processing operation, commonly referred to as "shrink." Under index-based purchase agreements, we purchase raw natural gas at the wellhead to replace the natural gas that we consume in processing, and we typically bear the full cost of the plant fuel and shrink, with the excess residue gas being sold monthly at index-based prices. By using this contract type, the producer is kept whole on a Btu basis. This type of contract exposes us to the keep-whole spread, or gross processing spread, which is the relative difference in the economic value between NGLs and natural gas on a Btu basis. The main factors that affect our keep-whole margins include:

- shrink,
- plant fuel consumed,
- transportation and fractionation costs incurred on the NGLs,
- gross processing spread, and
- the natural gas, crude oil and NGL prices received for products sold.

Excluding any gain on sale of assets, operating income from our Natural Gas Gathering and Processing segment was 42 percent, 46 percent and 17 percent of our consolidated operating income in 2007, 2006 and 2005, respectively. Operating revenue of this segment is derived primarily from POP and fee contracts. We use derivative instruments to mitigate our sensitivity to fluctuations in the price of natural gas, condensate and NGLs. Our Natural Gas Gathering and Processing segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for 35 percent of our Natural Gas Gathering and Processing segment's revenues in 2007 and 2006. Our Natural Gas Gathering and Processing segment had no intersegment sales in 2005. A portion of our revenues are from ONEOK and its affiliates.

Market Conditions and Seasonality - Supply - Natural gas supply is affected by rig availability, operating capability and producer drilling activity, which is sensitive to commodity prices, geological success, available capital and regulatory control. Relatively high natural gas and crude oil prices, as well as favorable long-term projections of U.S. demand, continued to drive increased drilling in 2007 in the Mid-Continent and Rocky Mountain regions, which are our primary supply regions.

In the Mid-Continent region, the gathering and processing assets we acquired in the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas are well established. However, we anticipate continuing volumetric declines in certain fields that supply our gathering and processing operations. Additionally, there is excess processing capacity, particularly in the Hugoton production region, which includes the Bushton Plant. Partly as a result of the Bushton Plant's inability to recover certain NGLs, such as ethane, the plant was at an economic disadvantage to the region's other cryogenic plants, and it was temporarily idled on January 1, 2007. See discussion on page 26.

In the Williston Basin, we connected more wells in 2007 than in prior years as a result of increased drilling activity. Transportation and refining capacity constraints for crude oil continue to only moderately impact natural gas production in the Williston Basin. Further development of the Big George coals, located in the center of the Powder River Basin, resulted in greater volumes during 2007, compared with 2006, for our wholly owned assets and joint-venture interests in Bighorn Gas Gathering and Fort Union Gas Gathering.

Demand - Demand for gathering and processing services is typically aligned with the supply of natural gas, which generally flows from a producing area at a relatively steady but gradually declining pace over time unless new reserves are added. Our plant operations can be adjusted to respond to market conditions, such as demand for ethane. By changing, within limits, the temperature and pressure at which raw natural gas is processed, we can produce more of the specific commodity that has the most favorable price or price spread.

Commodity Prices - Crude oil, natural gas and NGL prices are volatile due to market conditions. Storage injection and withdrawal rates, as well as available storage capacity, can also have an impact on commodity prices. We are exposed to market risk associated with adverse changes in commodity prices. Our primary exposures arise from the sale of natural gas, NGLs and condensate with respect to our processing contracts. To a lesser extent, we are exposed to the relative price differential between NGLs and natural gas, the risk of price fluctuations and the cost of intervening transportation at various market locations, and the demand for our products by the petrochemical industry and others.

Seasonality - Some of this segment's products are subject to weather-related seasonal demand. Cold temperatures typically increase demand for natural gas and propane, which are used to heat homes and businesses. Warm temperatures typically drive demand for natural gas used for gas-fired electric generation used to cool residential and commercial properties. Demand for iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor

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fuel, may also be subject to some variability when automotive travel is higher. During periods of peak demand for a certain commodity, prices for that product typically increase, which influences processing decisions.

Competition - The gathering and processing business remains relatively fragmented despite significant consolidation in the industry. We compete for natural gas supplies with major integrated exploration and production companies, pipeline companies and their affiliated marketing companies, national and local natural gas gatherers and processors, and marketers in the Mid-Continent and Rocky Mountain regions.

Due to the unprecedented strength of the energy commodity market over the past two years, gathering and processing rates have become increasingly competitive. As a result, we may not be successful in obtaining new natural gas supplies to offset declines and may lose some existing supplies to competitors. We are responding to these industry conditions by making capital investments to improve plant processing flexibility and reduce operating costs, evaluating consolidation opportunities to maximize earnings, selling assets in non-core operating areas and renegotiating unprofitable contracts. Contracts covering approximately 84 percent of our volumes under keep-whole contracts contain language that effectively converts these contracts into fee contracts when the keep-whole spread is negative.

Government Regulation - The FERC has traditionally maintained that a processing plant is not a facility for the transportation or sale for resale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the Natural Gas Act. Although the FERC has made no specific declaration as to the jurisdictional status of our natural gas processing operations or facilities, our natural gas processing plants are primarily involved in removing NGLs and, therefore, we believe, are exempt from FERC jurisdiction. The Natural Gas Act also exempts natural gas gathering facilities from the jurisdiction of the FERC. Interstate transmission facilities remain subject to FERC jurisdiction. The FERC has historically distinguished between these two types of facilities, either interstate or intrastate, on a fact-specific basis. We believe our gathering facilities and operations meet the criteria used by the FERC for non-jurisdictional gathering facility status. We can transport residue gas from our plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act.

Oklahoma and Kansas also have statutes regulating, to various degrees, the gathering of natural gas in those states. In each state, regulation is applied on a case-by-case basis if a complaint is filed against the gatherer with the appropriate state regulatory agency.

Natural Gas Pipelines

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We seek to maintain a competitive cost structure and increase throughput and growth of our existing natural gas pipelines and storage assets through extensions and expansions supported by long-term transportation and reservation contracts.

Segment Description - Our Natural Gas Pipelines segment is comprised of our previous interstate natural gas pipelines segment and the natural gas assets of our previous pipelines and storage segment. This segment primarily operates regulated natural gas transmission pipelines, natural gas storage facilities, and non-processable natural gas gathering facilities. We also provide interstate natural gas transportation and storage service in accordance with Section 311(a) of the Natural Gas Policy Act.

Our interstate natural gas pipeline assets transport natural gas through FERC-regulated interstate natural gas pipelines in Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipelines include Midwestern Gas Transmission, Guardian Pipeline, Viking Gas Transmission, OkTex Pipeline and a 50 percent interest in Northern Border Pipeline.

Our intrastate natural gas pipeline assets in Oklahoma have access to the major natural gas producing areas and transport natural gas throughout the state. We also have access to the major natural gas producing area in south central Kansas. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin, and transport natural gas to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market, north into the Mid-Continent market and west to the California market.

We own or reserve storage capacity in underground natural gas storage facilities in Oklahoma, Kansas and Texas.

Our transportation contracts for our regulated natural gas activities are based upon rates stated in our tariffs. Tariffs specify the maximum rates customers can be charged, which can be discounted to meet competition if necessary, and the general terms and conditions for pipeline transportation service, which are established at FERC or appropriate state jurisdictional agency proceedings known as rate cases. In Texas and Kansas, natural gas storage service is a fee business that may be regulated by the state in which the facility operates and by the FERC for certain types of services. In Oklahoma, natural gas gathering and natural gas storage operations are not subject to rate regulation and have market-based rate authority from the FERC for certain types of services.

Our Natural Gas Pipelines segment's revenues are typically derived from fee services from the following types of contracts.

- Firm Service - Customers can reserve a fixed quantity of pipeline or storage capacity for the term of their contract. Under this type of contract, the customer pays a fixed fee for a specified quantity regardless of their actual usage. The customer then typically pays incremental fees, known as commodity charges, that are based upon the actual volume of natural gas they transport or store and/or we may retain a specified volume of natural gas in-kind for fuel. Under the firm service contract, the customer is generally guaranteed access to the capacity they reserve.
- Interruptible Service - Customers with interruptible service transportation and storage agreements may utilize available capacity after firm service requests are satisfied or on an as-available basis. Interruptible service customers are typically assessed fees, such as a commodity charge, based on their actual usage and/or we may retain a specified volume of natural gas in-kind for fuel. Under the interruptible service contract, the customer is not guaranteed use of our pipelines and storage facilities unless excess capacity is available.

Excluding any gain on sale of assets, operating income from our Natural Gas Pipelines segment was 25 percent, 31 percent and 83 percent of our consolidated operating income in 2007, 2006 and 2005, respectively. Our Natural Gas Pipelines segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for less than 1 percent of our Natural Gas Pipelines segment's revenues in 2007 and 2006, respectively. Our Natural Gas Pipelines segment had no intersegment sales in 2005. A portion of our revenue is derived from services provided to ONEOK and its affiliates.

Market Conditions and Seasonality - Supply - The supply of natural gas for Viking Gas Transmission and Northern Border Pipeline originates in Canada. Significant factors that can impact the supply of Canadian natural gas transported by our pipelines are the Canadian natural gas available for export, Canadian storage capacity and demand for Canadian natural gas in other U.S. consumer markets. The supply of natural gas to our Guardian, Midwestern and Mid-Continent pipelines and storage assets currently depends on the pace of natural gas drilling activity by producers and the decline rate of existing production in the major natural gas production areas in the Mid-Continent region, including the Anadarko Basin, Hugoton Basin, Central Kansas Uplift Basin and Permian Basin. United States natural gas drilling rig counts increased in 2007 compared with 2006. The natural gas supply from the Gulf Coast also supports our Mid-Continent and upper Midwest pipeline facilities. This supply source is primarily dependent on offshore Gulf Coast production and, to a lesser degree, imports of liquefied natural gas.

Demand - Demand for pipeline transportation service and natural gas storage is directly related to demand for natural gas in the markets that the natural gas pipelines and storage facilities serve, and is affected by weather, the economy, and natural gas and NGL price volatility. The effect of weather on our natural gas pipelines operations is discussed below under "Seasonality." The strength of the economy directly impacts manufacturing and industrial companies that rely on natural gas. Commodity price volatility can influence customers' decisions related to the production of natural gas versus NGLs and natural gas storage injection and withdrawal activity.

Commodity Prices - We are exposed to market risk when existing contracts expire and are subject to renegotiation with customers that have competitive alternatives and analyze the market price spread or basis differential between receipt and delivery points along the pipeline to determine their expected gross margin. The anticipated margin and its variability are important determinants of the transportation rate customers are willing to pay. Natural gas storage revenue is impacted by the differential between forward pricing of natural gas physical contracts and the price of natural gas on the spot market. Our fuel costs and the value of the retained fuel in-kind are also impacted by adverse changes in the commodity price of natural gas.

Seasonality - Demand for natural gas is seasonal. Weather conditions throughout the United States can significantly impact regional natural gas supply and demand. High temperatures can increase demand for gas-fired electric generation to cool residential and commercial properties. Low precipitation levels can impact the demand for natural gas that is used to fuel irrigation activity in the Mid-Continent region. Cold temperatures can lead to greater demand for our transportation services due to increased demand for natural gas.

To the extent that pipeline capacity is contracted under firm service transportation agreements, revenue, which is generated primarily from demand charges, is not significantly impacted by seasonal throughput variations. However, when transportation agreements expire, seasonal demand can impact re-contracting of firm service transportation capacity.

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Natural gas storage is necessary to balance the relatively steady natural gas supply with the seasonal demand of residential, commercial and electric power generation users. The majority of our storage capacity is contracted under term agreements. A small portion of our storage capacity is retained for operational purposes and seasonal market activity.

Competition - Our Natural Gas Pipelines segment competes with other pipeline companies and other storage facilities for natural gas. Competition among pipelines and natural gas storage facilities is based primarily on fees for service and proximity to natural gas supply areas and markets. Competition for natural gas transportation services continues to increase as the FERC and state regulatory bodies continue to encourage more competition in the natural gas markets.

Government Regulation - Our interstate natural gas pipelines are regulated under the Natural Gas Act and Natural Gas Policy Act, which give the FERC jurisdiction to regulate virtually all aspects of this business segment, such as transportation of natural gas, rates and charges for services, construction of new facilities, depreciation and amortization policies, acquisition and disposition of facilities, and initiation and discontinuation of services.

Likewise, our intrastate natural gas pipelines in Oklahoma, Kansas and Texas are regulated by the OCC, KCC and RRC, respectively. While we have flexibility in establishing natural gas transportation rates with customers, there is a maximum rate that we can charge our customers in Oklahoma and Kansas.

Natural Gas Liquids Gathering and Fractionation

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We seek to maximize our value by increasing facility utilization and efficiently managing the operating costs of our natural gas liquids assets, which consist of facilities that gather, fractionate and treat NGLs and store NGL purity products in the Mid-Continent and Gulf Coast regions.

Segment Description - Our former natural gas liquids segment is now called our Natural Gas Liquids Gathering and Fractionation segment. As part of the ONEOK Transactions described in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures," in April 2006, we acquired all of ONEOK's natural gas liquids assets and created a new segment that consisted solely of these newly acquired natural gas liquids assets.

Our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs produced by natural gas processing plants located in Oklahoma, Kansas, the Texas panhandle and the Texas Gulf Coast, and stores and markets NGL products. We connect the NGL production basins in Oklahoma, Kansas and the Texas panhandle with the key natural gas liquids market centers in Conway, Kansas, and Mont Belvieu, Texas.

Most natural gas produced at the wellhead contains a mixture of NGL components such as ethane, propane, iso-butane, normal butane and natural gasoline. Natural gas processing plants remove the NGLs from the natural gas stream to realize the higher economic value of the NGLs and to meet natural gas pipeline quality specifications, which limit NGLs in the natural gas stream by liquid and Btu content. The NGLs that are separated from the natural gas stream at the natural gas processing plants remain in a mixed, unfractionated form until they are gathered, primarily by pipeline, and delivered to our fractionators. A fractionator, by applying heat and pressure, separates the unfractionated NGL stream into marketable purity products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products are then stored and/or distributed to our customers, such as petrochemical plants, heating fuel users and motor gasoline manufacturers.

Operating revenue of this segment is derived primarily from exchange services, optimization, isomerization and storage.

- Our exchange services business collects fees to gather, fractionate and treat unfractionated NGLs thereby converting them into NGL products that are stored and shipped to a market center or customer-designated location.
- Our optimization business utilizes our asset base, contract portfolio and market knowledge to capture locational and seasonal price spreads. We move NGL products between Conway, Kansas, and Mont Belvieu, Texas, in order to capture the locational price spreads between the two market centers. Our NGL storage facilities in the Mid-Continent and Gulf Coast regions are used to capture seasonal price variances.
- Our isomerization business captures the price spread when normal butane is converted into the more valuable iso-butane at an isomerization unit in Conway, Kansas. Iso-butane is used in the refining industry to upgrade the octane of motor gasoline.
- Our storage business collects fees to store NGLs in Conway, Kansas, and Mont Belvieu, Texas.

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Excluding any gain on sale of assets, operating income from our Natural Gas Liquids Gathering and Fractionation segment was 25 percent and 22 percent of our consolidated operating income in 2007 and 2006, respectively. We did not have a Natural Gas Liquids Gathering and Fractionation segment prior to 2006. Our Natural Gas Liquids Gathering and Fractionation segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for less than one percent of our Natural Gas Liquids Gathering and Fractionation segment's revenues in 2007 and 2006, respectively.

Market Conditions and Seasonality - Supply - Supply for our Natural Gas Liquids Gathering and Fractionation segment depends on the pace of crude oil and natural gas drilling activity by producers, the decline rate of existing production, and the liquids content of the natural gas that is produced and processed. Our Mont Belvieu fractionation operation receives NGLs from a variety of processors and pipelines located in the Gulf Coast, west and central Texas, and the Rocky Mountain regions.

Our NGL gathering pipelines are also affected by operational or market-driven changes that impact the output of natural gas processing plants to which they are connected. The differential between the composite price of NGL products and the price of natural gas, particularly the differential between the price of ethane and the price of natural gas, may influence processing plant output. Typically, the forward price of ethane compared with the forward price of natural gas provides minimal or no processing spread. However, when the physical transactions occur, the price of ethane to natural gas has historically provided a positive processing spread. During 2007, ethane values remained above those of natural gas on a relative price basis, which resulted in ethane recovery from processing plants that deliver to our natural gas liquids gathering pipelines.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations impacts the volume of unfractionated NGLs produced by processing plants, thereby affecting the demand for natural gas liquids gathering and fractionation services. Natural gas and propane are subject to weather-related seasonal demand. Other products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as iso-butane and natural gasoline, which are used by the refining industry as blending stocks for motor fuel, ethane, and an ethane/propane mix. This ethane/propane mix is used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fiber.

Commodity Prices - In recent years, crude oil, natural gas and NGL prices have been volatile due to market conditions. We are exposed to market risk associated with adverse changes in the price of NGLs, the basis differential between the Mid-Continent and Gulf Coast regions, and the relative price differential between natural gas, NGLs and individual NGL products, which impact our NGL purchases, sales, exchange and storage revenue. When natural gas prices are higher relative to NGL prices, NGL production may decline, which could negatively impact our exchange services revenue. When the basis differential between the Mid-Continent and Gulf Coast regions is narrow, optimization opportunity and margins may decline. NGL storage revenue may be impacted by price volatility and forward pricing of NGL physical contracts versus the price of NGLs on the spot market.

Seasonality - Some NGL products produced by our natural gas liquids facilities are subject to weather-related seasonal demand, such as propane, which is primarily used to heat residential properties during the winter heating season. Demand for iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, may also be subject to some variability when automotive travel is higher.

Competition - We compete with other fractionators, storage providers and gatherers for natural gas liquids supplies in the Rocky Mountain, Mid-Continent and Gulf Coast regions. We are making capital investments to access new supplies, increase gathering and fractionation capacity, increase storage capabilities and reduce operating costs so that we may compete more effectively.

Government Regulations - Revenues generated by our pipelines in both Oklahoma and Kansas are not regulated by the FERC or those states' respective corporation commissions.

Natural Gas Liquids Pipelines

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We seek to increase throughput and continue to provide cost-effective transportation for NGLs between the Mid-Continent, the Gulf Coast and the Midwest markets near Chicago, Illinois. We pursue growth of our interstate natural gas liquids pipelines by making capital investments to expand our access to new supplies and increase our pipeline capacity.

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Segment Description - Our Natural Gas Liquids Pipelines segment is comprised of the natural gas liquids assets of our previous pipelines and storage segment, and our natural gas liquids and refined petroleum products pipeline systems and related assets acquired from Kinder Morgan in October 2007. This segment operates FERC-regulated natural gas liquids gathering and distribution pipelines and associated above- and below-ground storage facilities. Our natural gas liquids gathering pipelines deliver unfractionated NGLs gathered in Oklahoma, Kansas and the Texas panhandle to our Mid-Continent fractionation facilities in Medford, Oklahoma. Our natural gas liquids distribution pipelines deliver NGL products to the natural gas liquids market hubs in Conway, Kansas, and Mont Belvieu, Texas. Through our acquisition of the natural gas liquids assets from Kinder Morgan, we acquired terminal and storage facilities as well as natural gas liquids and refined petroleum products pipelines that connect our Mid-Continent assets with the Midwest markets near Chicago, Illinois. Our natural gas liquids gathering and distribution pipelines operate in Oklahoma, Kansas, Nebraska, Missouri, Iowa, Illinois and Texas. We have terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois.

Operating revenue for this segment is primarily derived from transporting product under our FERC-regulated tariffs. Tariffs specify the rates we can charge our customers and the general terms and conditions for NGL transportation service on our pipelines. Our tariffs include specifications regarding the receipt and delivery of NGLs at points along the pipeline systems. We generally charge tariff rates under a FERC-approved indexing methodology, which allows charging rates up to a prescribed ceiling that changes annually based on the year-to-year change in the Producer Price Index for finished goods. The FERC also permits interstate natural gas liquids pipelines to support rates by using a cost-of-service methodology, competitive market price or an agreement with a pipeline's non-affiliated shipper.

Our storage services are offered through a combination of market-based rates and FERC-regulated tariffs and are generally used for operational purposes and to store our customers' NGL products. Under some of our FERC-regulated tariffs, customers are allotted earned storage capacity based upon their utilization of transport services. When a customer exceeds its earned storage capacity, we charge the customer an excess storage fee. In some of our product storage agreements, we may charge customers storage reservation fees to reserve a specific storage capacity or we may charge customers based on the quantity of capacity utilized.

Excluding any gain on sale of assets, operating income from our Natural Gas Liquids Pipelines segment was 9 percent and 7 percent of our consolidated operating income in 2007 and 2006, respectively. We did not have a Natural Gas Liquids Pipelines segment prior to 2006. Our Natural Gas Liquids Pipelines segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for 83 percent and 100 percent of our Natural Gas Liquids Pipelines segment's revenues in 2007 and 2006, respectively.

Market Conditions and Seasonality - Supply - The supply for our Natural Gas Liquids Pipelines segment depends on the pace of crude oil and natural gas drilling activity by producers, the decline rate of existing production, and the liquids content of the natural gas that is produced and processed. Our unfractionated NGLs are primarily gathered from natural gas processing plants in Oklahoma, Kansas and the Texas panhandle. The supply of NGLs gathered are affected by operational or market-driven changes that impact the output of natural gas processing plants to which we are connected. The differential between the composite price of NGL products and the price of natural gas, particularly the differential between the price of ethane and the price of natural gas, may influence processing plant output. Typically, the forward price of ethane compared with the forward price of natural gas provides minimal or no processing spread. However, as the prices settle, the price of ethane to natural gas has historically provided a positive processing spread. During 2007, ethane prices remained above natural gas prices on a relative basis.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations impacts the volume of unfractionated NGLs produced by processing plants, which affects the demand for our NGL gathering and distribution services. Propane is subject to weather-related seasonal demand. Other products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as butanes and natural gasoline, which are used by the refining industry as blending stocks for motor fuel. Ethane/propane mix is used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fiber.

Commodity Prices - In recent years, crude oil, natural gas and NGL prices have been volatile due to market conditions. We are exposed to market risk associated with adverse changes in the price of NGLs, the basis differential between the Mid-Continent, Chicago, Illinois, and Gulf Coast regions, and the relative price differential between natural gas, unfractionated NGLs and individual NGL products, which impact the distribution of NGL products. When natural gas prices are higher relative to NGL prices, NGL production may decline, which could negatively impact the revenues of our gathering and distribution activities. When the basis differential between the Mid-Continent, Chicago, Illinois, and the Gulf Coast regions are narrow, NGL shipments may decline, resulting in a reduction of transportation revenues.

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Seasonality - Some NGLs gathered and distributed by our natural gas liquids pipeline facilities are subject to weather-related seasonal demand, such as propane, which is primarily used to heat residential properties during the winter heating season and for agricultural purposes such as grain drying in the fall. Demand for normal butane, iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, may also be subject to some variability when automotive travel is higher.

Competition - Our Natural Gas Liquids Pipelines segment competes with other pipeline companies and other storage facilities for NGLs. Competition among pipeline companies and NGL storage facilities is based primarily on fees for service and proximity to natural gas liquids supply areas and markets.

Government Regulation - Our interstate natural gas liquids pipelines are regulated by the FERC, which regulates virtually all aspects of this business segment, such as transportation of NGLs and refined products, rates and charges for services, depreciation and amortization policies, and initiation and discontinuation of services. The KCC regulates intrastate transportation of NGLs and refined products in Kansas.

Other

Segment Description - Our Other segment includes Black Mesa, which is a pipeline designed to transport crushed coal suspended in water along 273 miles of pipeline that originates at a coal mine in Kayenta, Arizona, and terminates at the Mohave Generating Station (Mohave) in Laughlin, Nevada. The coal slurry pipeline was the sole source of fuel for Mohave and was fully contracted to Peabody Western Coal until December 31, 2005. The water used by the coal slurry pipeline was supplied from an aquifer in the Navajo Nation and Hopi Tribe joint-use area until December 31, 2005.

On December 31, 2005, Black Mesa's transportation contract with the coal supplier of Mohave expired, and our coal slurry pipeline operations were shut down. In June 2006, Southern California Edison Company (SCE) completed a comprehensive study of the water source, coal supply and transportation issues, and announced that it would no longer pursue the resumption of plant operations. In February 2007, another Mohave co-owner, Salt River Project, announced it was ending its efforts to return the plant to service. We plan to either divest the Black Mesa pipeline or commence decommissioning of the pipeline during 2008.

ENVIRONMENTAL AND SAFETY MATTERS

Information about our environmental matters is included in Note H of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Pipeline Safety - We are subject to United States Department of Transportation integrity management regulations. The Pipeline Safety Improvement Act requires pipeline companies to perform integrity assessments on segments of a pipeline that pass through densely populated areas or near specifically identified sites that are designated as high consequence areas. To our knowledge, we are substantially in compliance with all material requirements associated with the various regulations.

Air and Water Emissions - The federal Clean Air Act and Clean Water Act and analogous state laws impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federal operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants discharged in United States water.

Superfund - The Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or Superfund, imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a facility where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies.

Chemical Site Security - The United States Department of Homeland Security (Homeland Security) released an interim rule in April 2007 that requires companies to provide reports on sites where certain chemicals, including many hydrocarbon products, are stored. After receiving these reports, Homeland Security will identify which sites are required to implement security measures. Homeland Security is in the initial stages of implementing this rule, and the extent to which the rule will require us to undertake additional expenditures for site security is uncertain at this point.

Climate Change - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (i) maintaining an accurate greenhouse gas emissions inventory, (ii) improving the efficiency of our various pipeline and gas processing facilities, (iii) following developing technologies for emission control, (iv) following developing technologies to capture carbon dioxide to keep it from reaching the atmosphere, and (v) analyzing options for future energy investment.

Currently, operating entities within our Partnership participate in the gathering and processing sector and the transmission sector of the EPA's Natural Gas STAR Program to voluntarily reduce methane emissions. In addition, we continue to focus on reducing methane loss through expanded implementation of best practices across our operations and analyzing options for additional emission reductions, including (i) closing older facilities and routing products to more efficient facilities, (ii) self-imposing permit limits at facilities where operationally feasible, (iii) utilizing electric motors on select compressor applications, and (iv) utilizing methods to limit the release of methane gas during pipeline maintenance and operations.

EMPLOYEES

We do not directly employ any of the persons responsible for managing, operating or providing us with services related to our day-to-day business affairs. We have a service agreement with ONEOK, ONEOK Partners GP and NBP Services (the Services Agreement) under which our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides us an equivalent type and amount of services that it provides to its other affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP operates our interstate natural gas pipeline assets according to each pipeline's operating agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. As of January 31, 2008, we utilized the services of 1,136 full-time employees in addition to the other resources provided by ONEOK and its affiliates.

AVAILABLE INFORMATION

You can access financial and other information at our website at www.oneokpartners.com. We make available on our website, free of charge, copies of our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct, Governance Guidelines, Accounting and Financial Reporting Code of Ethics, Partnership Agreement and the written charter of our Audit Committee are also available on our website, and we will make available, free of charge, copies of these documents upon request.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report on Form 10-K, including "Forward-Looking Statements," which are included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation.

RISKS INHERENT IN OUR BUSINESS

The volatility of natural gas, crude oil and NGL prices could adversely affect our cash flow.

A significant portion of our revenues are derived from the sale of commodities received as payment for our natural gas gathering and processing services, for transportation and storage of natural gas and NGLs, and for the fractionation of NGLs. As a result, we are sensitive to commodity price fluctuations. Commodity prices have been and are likely to continue to be volatile in the future. High commodity prices and large commodity price spreads may not continue and could drop precipitously in a short period of time. Our commodity prices are subject to wide fluctuations in response to a variety of factors beyond our control, including the following:

- relatively minor changes in the supply of, and demand for, domestic and foreign energy;
- market uncertainty;
- the availability and cost of transportation capacity;

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The following table is a reconciliation of our provision for income taxes for the periods indicated.

	Years Ended December 31,		
	2007	2006	2005
	(Thousands of dollars)		
Pretax income from continuing operations	$ 416,589	$ 420,849	$ 152,299
Federal statutory income tax rate	35.0%	35.0%	35.0%
Provision for federal income taxes	145,806	147,297	53,305
Partnership earnings not subject to tax	(141,884)	(144,928)	(48,630)
State income taxes	4,772	2,990	1,117
Other, net	148	143	-
Income tax expense	$ 8,842	$ 5,502	$ 5,792

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated.

	Years Ended December 31,	
	2007	2006
	(Thousands of dollars)	
Deferred tax assets:		
Net operating losses	$ 4,715	$ 7,971
Other	1,596	129
Total deferred tax assets	6,311	8,100
Deferred tax liabilities:		
Excess of tax over book depreciation and depletion	7,934	5,414
Regulatory assets	2,544	2,526
Other	77	79
Total deferred tax liabilities	10,555	8,019
Net deferred tax assets/ (liabilities)	$ (4,244)	$ 81

At December 31, 2007, we had approximately $5.0 million of tax benefits available related to net operating loss carryforwards, which will expire between the years 2022 and 2026. We believe that it is more likely than not that the tax benefits of the net operating loss carryforwards will be utilized prior to their expiration; therefore, no valuation allowance is necessary.

We had income taxes payable of approximately $3.1 million at December 31, 2007. Cash paid for income taxes, net, was approximately $1.0 million, $0.6 million and $1.4 million at December 31, 2007, 2006 and 2005, respectively.

J. SEGMENTS

Segment Descriptions - In July 2007, we announced a series of organizational changes that led to the realignment of our previous business segments. Our financial results are now reported in these four segments: (i) Natural Gas Gathering and Processing, which remains unchanged, (ii) Natural Gas Pipelines, which is comprised of our former interstate natural gas pipelines segment and the natural gas assets of our former pipelines and storage segment, (iii) Natural Gas Liquids Gathering and Fractionation, which remains unchanged, and (iv) Natural Gas Liquids Pipelines, which is comprised of the natural gas liquids assets of our former pipelines and storage segment. Prior periods have been restated to reflect these segment changes.

Our operations are divided into these strategic business segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment, as follows:

- our Natural Gas Gathering and Processing segment primarily gathers and processes raw natural gas,
- our Natural Gas Pipelines segment primarily operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities,
- our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs and stores and markets NGL products, and
- our Natural Gas Liquids Pipelines segment primarily operates our FERC-regulated interstate natural gas liquids gathering and distribution pipelines.

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The acquisition of the ONEOK Energy Assets in April 2006 is accounted for in our consolidated financial statements effective January 1, 2006. In connection with these transactions, we formed our former natural gas liquids segment and our former pipelines and storage segment.

Accounting Policies - The accounting policies of the segments are described in Note A. Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from ONEOK and its subsidiaries that utilize transportation and storage services. Corporate overhead costs relating to a reportable segment have been allocated for the purpose of calculating operating income. Our equity method investments do not represent operating segments.

Northern Border Pipeline was no longer consolidated effective January 1, 2006. For our Natural Gas Pipelines segment, Northern Border Pipeline's revenues represented approximately 85 percent of the segment's revenues in 2005.

Customers - The main customers for our Natural Gas Gathering and Processing segment are primarily major and independent oil and gas production companies. Our Natural Gas Liquids Gathering and Fractionation segment's customers are primarily natural gas gathering and processing companies and petrochemical, refining and NGL marketing companies. Companies served by our Natural Gas Pipelines segment include local distribution companies, power generating companies, natural gas marketing companies and petrochemical companies. Our Natural Gas Liquids Pipelines segment's customers are primarily NGL gathering companies, propane distributors and petrochemical and refining companies.

In 2007 and 2006, we had no single external customer from which we received 10 percent or more of our consolidated revenues. For 2005, we had two customers that accounted for more than 10 percent of our total consolidated operating revenues. In 2005, Lodgepole Energy Marketing (Lodgepole) and BP Canada accounted for $123.2 million (18 percent) and $114.4 million (16 percent), respectively, of our consolidated operating revenues. Operating revenues from Lodgepole are recorded in our Natural Gas Gathering and Processing segment. Our Natural Gas Gathering and Processing segment and Natural Gas Pipelines segment have recorded operating revenues from BP Canada.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated. Amounts in prior periods have been restated to conform to our current presentation.

Year Ended December 31, 2007	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 433,139	$ 194,170	$ 4,562,178	$ 15,280	$ 27	$5,204,794
Sales to affiliated customers	519,755	107,009	-	-	-	626,764
Intersegment sales	505,756	785	25,115	76,555	(608,211)	-
Operating revenue	$ 1,458,650	$ 301,964	$ 4,587,293	$ 91,835	$ (608,184)	$5,831,558
Gain on sale of assets	$ 1,825	$ 79	$ 39	$ 7	$ -	$ 1,950
Operating income	$ 187,815	$ 112,212	$ 111,976	$ 39,460	$ (4,680)	$ 446,783
Equity earnings from investments	$ 26,399	$ 62,487	$ -	$ 1,022	$ -	$ 89,908
EBITDA	$ 259,246	$ 207,196	$ 134,393	$ 53,411	$ 2,872	$ 657,118
Investments in unconsolidated affiliates	$ 298,701	$ 426,992	$ -	$ 30,567	$ -	$ 756,260
Total assets	$ 1,564,697	$ 1,164,111	$ 1,881,397	$ 1,214,833	$ 287,027	$6,112,065
Capital expenditures	$ 83,820	$ 138,919	$ 123,555	$ 363,460	$ 104	$ 709,858

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $252.5 million and operating income of $82.9 million for 2007.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

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Year Ended December 31, 2006	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 478,848	$ 195,063	$ 3,467,048	$ -	$ 1,587	$4,142,546
Sales to affiliated customers	476,361	121,088	(1,747)	-	-	595,702
Intersegment sales	520,881	857	27,675	66,496	(615,909)	-
Operating revenue	$ 1,476,090	$ 317,008	$ 3,492,976	$ 66,496	$ (614,322)	$4,738,248
Gain on sale of assets	$ 373	$ 114,890	$ 47	$ 7	$ 166	$ 115,483
Operating income	$ 180,615	$ 237,330	$ 88,779	$ 29,086	$ (24,598)	$ 511,212
Equity earnings from investments	$ 22,616	$ 72,835	$ -	$ 432	$ -	$ 95,883
EBITDA	$ 249,136	$ 343,384	$ 109,753	$ 41,692	$ (15,396)	$ 728,569
Investments in unconsolidated affiliates	$ 294,308	$ 445,339	$ -	$ 9,232	$ -	$ 748,879
Total assets	$ 1,615,969	$ 1,224,576	$ 1,522,177	$ 511,949	$ 47,046	$4,921,717
Capital expenditures	$ 80,982	$ 48,598	$ 21,761	$ 49,322	$ 1,083	$ 201,746

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $269.4 million and operating income of $211.0 million, including $113.9 million from a gain on sale of assets, for 2006.
(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

Year Ended December 31, 2005	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 275,287	$ 396,402	$ -	$ -	$ 24,572	$ 696,261
Sales to affiliated customers	-	7,683	-	-	-	7,683
Intersegment sales	-	-	-	-	-	-
Operating revenue	$ 275,287	$ 404,085	$ -	$ -	$ 24,572	$ 703,944
Operating income	$ 44,714	$ 214,168	$ -	$ -	$ (2,114)	$ 256,768
Equity earnings from investments	$ 22,473	$ 2,263	$ -	$ -	$ -	$ 24,736
EBITDA	$ 83,840	$ 285,871	$ -	$ -	$ 2,260	$ 371,971
Investments in unconsolidated affiliates	$ 254,286	$ 36,470	$ -	$ -	$ -	$ 290,756
Total assets	$ 594,379	$ 1,888,980	$ -	$ -	$ 44,407	$2,527,766
Capital expenditures	$ 16,602	$ 39,641	$ -	$ -	$ 3,639	$ 59,882

(a) - For 2005, all of our Natural Gas Pipelines segment's operations are regulated.

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We evaluate our performance based on EBITDA, which we define as earnings before interest, income taxes, depreciation and amortization less the cost of the equity component of AFUDC. Management uses EBITDA to compare the financial performance of its segments and to internally manage those business segments. Management believes that EBITDA provides useful information to investors as a measure of comparison with peer companies. EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. EBITDA calculations may vary from company to company, so our computation of EBITDA may not be comparable with a similarly titled measure of another company.

The following tables set forth the reconciliation of net income to EBITDA by operating segment for the periods indicated.

Year Ended December 31, 2007	**Natural Gas Gathering and Processing**	**Natural Gas Pipelines**	**Natural Gas Liquids Gathering and Fractionation**	**Natural Gas Liquids Pipelines**	**Other and Eliminations**	**Total**
			(Thousands of dollars)			
Net income	$ 222,838	$ 160,542	$ 117,362	$ 46,012	$ (139,007)	$407,747
Minority interests	-	387	-	29	-	416
Interest expense, net	(8,720)	11,785	(6,103)	3,176	138,809	138,947
Depreciation and amortization	45,099	32,380	23,134	13,062	29	113,704
Income taxes	29	5,772	-	-	3,041	8,842
Allowance for equity funds used during construction	-	(3,670)	-	(8,868)	-	(12,538)
EBITDA	$ 259,246	$ 207,196	$ 134,393	$ 53,411	$ 2,872	$657,118

Year Ended December 31, 2006	Natural Gas Gathering and Processing	Natural Gas Pipelines	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines	Other and Eliminations	Total
			(Thousands of dollars)			
Net income	$ 190,701	$ 269,995	$ 77,050	$ 24,675	$ (117,235)	$445,186
Minority interests	-	2,392	-	-	-	2,392
Interest expense, net	4,590	26,252	8,776	5,422	88,442	133,482
Depreciation and amortization	43,032	32,841	20,738	12,035	13,399	122,045
Income taxes	10,813	12,822	3,189	847	(2)	27,669
Allowance for equity funds used *during construction*	-	(918)	-	(1,287)	-	(2,205)
EBITDA	$ 249,136	$ 343,384	$ 109,753	$ 41,692	$ (15,396)	$728,569

Year Ended December 31, 2005	Natural Gas Gathering and Processing	Natural Gas Pipelines	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines	Other and Eliminations	Total
			(Thousands of dollars)			
Net income	$ 67,552	$ 123,604	$ -	$ -	$ (44,143)	$147,013
Minority interests	-	45,674	-	-	-	45,674
Interest expense, net	219	44,990	-	-	41,694	86,903
Depreciation and amortization	16,045	67,608	-	-	2,708	86,361
Income taxes	24	4,522	-	-	2,001	6,547
Allowance for equity funds used during construction	-	(527)	-	-	-	(527)
EBITDA	$ 83,840	$ 285,871	$ -	$ -	$ 2,260	$371,971

The Williams Companies, Inc.
2007 Form 10-K

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 1-4174

The Williams Companies, Inc.
(Exact name of Registrant as Specified in Its Charter)

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**73-0569878** *(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma *(Address of Principal Executive Offices)*	**74172** *(Zip Code)*

918-573-2000
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $1.00 par value	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
5.50% Junior Subordinated Convertible Debentures due 2033

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second quarter was approximately $18,963,794,420.

The number of shares outstanding of the registrant's common stock outstanding at February 21, 2008 was 585,021,071.

DOCUMENTS INCORPORATED BY REFERENCE

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PART I

Item 1. ***Business***

In this report, Williams (which includes The Williams Companies, Inc. and, unless the context otherwise requires, all of our subsidiaries) is at times referred to in the first person as "we," "us" or "our." We also sometimes refer to Williams as the "Company."

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents electronically with the Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (Exchange Act). You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC's Internet website at *http://www.sec.gov.*

Our Internet website is *http://www.williams.com.* We make available free of charge on or through our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our Corporate Governance Guidelines, Code of Ethics, board committee charters and Code of Business Conduct are also available on our Internet website. We will also provide, free of charge, a copy of any of our corporate documents listed above upon written request to our Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

We are a natural gas company originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. We were founded in 1908 when two Williams brothers began a construction company in Fort Smith, Arkansas. Today, we primarily find, produce, gather, process and transport natural gas. Our operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, and the Eastern Seaboard.

We continue to use Economic Value Added ® (EVA ®) [1] as the basis for disciplined decision making around the use of capital. EVA ® is a tool that considers both financial earnings and a cost of capital in measuring performance. It is based on the idea that earning profits from an economic perspective requires that a company cover not only all of its operating expenses but also all of its capital costs. The two main components of EVA ® are net operating profit after taxes and a charge for the opportunity cost of capital. We derive these amounts by making various adjustments to our reported results and financial position, and by applying a cost of capital. We look for opportunities to improve EVA ® because we believe there is a strong correlation between EVA ® improvement and creation of shareholder value.

Our goal is to create superior sustainable growth in EVA ® and shareholder value. In early 2006, we set some ambitious three-year goals referred to as our game plan for growth. Our success in achieving the game plan for growth contributed to our significant accomplishments in 2007 designed to increase shareholder value, including:

- As a result of the sale of substantially all of our power assets to Bear Energy LP, a unit of The Bear Stearns Companies Inc. (NYSE: BSC) and strong business performance, our credit ratings were raised to investment grade.
- Continuing to increase our natural gas production through organic growth — natural gas production increased by 21 percent for the year.

[1] Economic Value Added ® (EVA ®) is a registered trademark of Stern, Stewart & Co.

- Initiating a $1 billion stock repurchase program.
- Creating a new pipeline-focused master limited partnership, Williams Pipeline Partners L.P. (WMZ)
- Continuing growing our midstream-focused master limited partnership, Williams Partners L.P. (WPZ), with two significant drop-down transactions.
- Successfully executing rate cases on both of our major pipeline systems, driving increased earnings in Gas Pipeline.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000.

2007 HIGHLIGHTS

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. The underwriters also exercised their option to purchase an additional 1.65 million common units at the same price.

In December 2007, Williams Partners L.P. (WPZ) acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million.

In December 2007, we repurchased $213 million of 7.125 percent notes due September 2011 and $22 million of 8.125 percent notes due March 2012.

On November 28, 2007, Transcontinental Gas Pipe Line Corporation (Transco) filed a formal stipulation and agreement with the Federal Energy Regulatory Commission (FERC) resolving all substantive issues in Transco's pending 2006 rate case. Final resolution of the rate case is subject to approval by the FERC.

On November 9, 2007, we closed on the sale of substantially all of our power business to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc., for $496 million, subject to post-closing adjustments. The assets sold included tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. This sale reduces the risk and complexity of our overall business.

In November 2007, our credit ratings were raised to investment grade based on improvements in our credit outlook. As we continue to invest and grow our natural gas businesses, our improved credit rating is expected to provide greater access to capital and more favorable loan terms. See additional discussion of credit ratings in *Management's Discussion and Analysis of Financial Condition* .

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. During 2007, we repurchased approximately 16 million shares for $526 million (including transaction costs) at an average cost of $33.08 per share.

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflects an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marks the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the rate case for Northwest Pipeline GP (Northwest Pipeline), formerly Northwest Pipeline Corporation.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 17 of our Notes to Consolidated Financial Statements for information with respect to each segment's revenues, profits or losses and total assets. See Note 9 for information with respect to property, plant and equipment for each segment.

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BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. To achieve organizational and operating efficiencies, our activities are primarily operated through the following business segments:

- *Exploration & Production* — produces, develops and manages natural gas reserves primarily located in the Rocky Mountain and Mid-Continent regions of the United States and is comprised of several wholly owned and partially owned subsidiaries including Williams Production Company LLC and Williams Production RMT Company.
- *Gas Pipeline* — includes our interstate natural gas pipelines and pipeline joint venture investments organized under our wholly owned subsidiary, Williams Gas Pipeline Company, LLC. Gas Pipeline also includes WMZ, our master limited partnership formed in 2007.
- *Midstream Gas & Liquids* — includes our natural gas gathering, treating and processing business and is comprised of several wholly owned and partially owned subsidiaries including Williams Field Services Group LLC and Williams Natural Gas Liquids, Inc. Midstream also includes WPZ, our master limited partnership formed in 2005.
- *Gas Marketing Services* — manages our natural gas commodity risk through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Gas Marketing, Inc.
- *Other* — primarily consists of corporate operations. Other also includes our interest in Longhorn Partners Pipeline, L.P. (Longhorn).

This report is organized to reflect this structure.

Detailed discussion of each of our business segments follows.

Exploration & Production

Our Exploration & Production segment, which is comprised of several wholly owned and partially owned subsidiaries, including Williams Production Company LLC and Williams Production RMT Company (RMT), produces, develops, and manages natural gas reserves primarily located in the Rocky Mountain (primarily New Mexico, Wyoming and Colorado) and Mid-Continent (Oklahoma and Texas) regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Arkoma, Green River and Fort Worth basins. Over 99 percent of Exploration & Production's domestic reserves are natural gas. Our Exploration & Production segment also has international oil and gas interests, which include a 69 percent equity interest in Apco Argentina Inc. (Apco Argentina), an oil and gas exploration and production company with operations in Argentina, and a four percent equity interest in Petrowayu S.A., a Venezuelan corporation that is the operator of a 100 percent interest in the La Concepcion block located in Western Venezuela.

Exploration & Production's primary strategy is to utilize its expertise in the development of tight-sands, shale, and coal bed methane reserves. Exploration & Production's current proved undeveloped and probable reserves provide us with strong capital investment opportunities for several years into the future. Exploration & Production's goal is to drill its existing proved undeveloped reserves, which comprise approximately 46 percent of proved reserves and to drill in areas of probable reserves. In addition, Exploration & Production provides a significant amount of equity production that is gathered and/or processed by our Midstream facilities in the San Juan basin.

Information for our Exploration & Production segment relates only to domestic activity unless otherwise noted. We use the terms "gross" to refer to all wells or acreage in which we have at least a partial working interest and "net" to refer to our ownership represented by that working interest.

Document	Parts Into Which Incorporated
Proxy Statement for the Annual Meeting of Stockholders to be held May 15, 2008 (Proxy Statement)	Part III

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Gas reserves and wells

The following table summarizes our U.S. natural gas reserves as of December 31 (using market prices on December 31 held constant) for the year indicated:

	2007	2006 (Bcfe)	2005
Proved developed natural gas reserves	2,252	1,945	1,643
Proved undeveloped natural gas reserves	1,891	1,756	1,739
Total proved natural gas reserves	4,143	3,701	3,382

No major discovery or other favorable or adverse event has caused a significant change in estimated gas reserves since year-end 2007. We have not filed on a recurring basis estimates of our total proved net oil and gas reserves with any U.S. regulatory authority or agency other than the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC, although Exploration & Production has not yet filed any information with respect to its estimated total reserves at December 31, 2007, with the DOE. Certain estimates filed with the DOE may not necessarily be directly comparable due to special DOE reporting requirements, such as the requirement to report gross operated reserves only. In 2006 and 2005 the underlying estimated reserves for the DOE did not differ by more than five percent from the underlying estimated reserves utilized in preparing the estimated reserves reported to the SEC.

Approximately 98 percent of our year-end 2007 United States proved reserves estimates were audited in each separate basin by Netherland, Sewell & Associates, Inc. (NSAI). When compared on a well-by-well basis, some of our estimates are greater and some are less than the estimates of NSAI. However, in the opinion of NSAI, the estimates of our proved reserves are in the aggregate reasonable by basin and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. These principles are set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. NSAI is satisfied with our methods and procedures in preparing the December 31, 2007 reserve estimates and saw nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us. Reserve estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust, which comprise approximately two percent of our total U.S. proved reserves, were prepared by Miller and Lents, LTD.

On December 12, 2007, the SEC issued a "Concept Release" to obtain information about the extent and nature of the public's interest in revising oil and gas reserves disclosure requirements which exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934. The Commission adopted the current oil and gas reserves disclosure requirement between 1978 and 1982. The Concept Release is intended to address significant changes in the oil and gas industry. Some commentators have expressed concern that the Commission's rules have not adapted to current practices and may not provide investors with the most useful picture of oil and gas reserves public companies hold. Comments were due to the Commission on February 19, 2008. At this time it is not possible to determine what effect changes the SEC may make, if any, will have on our reserve estimates and disclosures.

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Oil and gas properties and reserves by basin

The table below summarizes 2007 activity and reserves for each of our areas, with further discussion following the table.

	Wells Drilled (Gross)	Wells Drilled (Operated)	Wells Producing (Gross)	Wells Producing (Net)	Wellhead Production (Net Bcfe)	Proved Reserves (Bcfe)	% of Total Proved Reserves
Piceance	574	544	2,467	2,295	197	2,847	69%
San Juan	146	47	3,109	821	55	576	14%
Powder River	637	457	4,831	2,200	62	413	10%
Mid-Continent	80	63	539	339	17	184	4%
Other	153	1	454	18	3	123	3%
Total	1,590	1,112	11,400	5,673	334	4,143	100%

Piceance basin

The Piceance basin is located in northwestern Colorado and is our largest area of concentrated development. During 2007 we operated an average of 25 drilling rigs in the basin. As of December 2007, 14 of these rigs were the new high efficiency rigs designed to drill up to 22 wells from one location. This area has approximately 1,760 undrilled proved locations in inventory. Within this basin we own and operate natural gas gathering facilities including some 280 miles of gathering lines and associated field compression. Approximately 88% of the gas gathered is our own equity production. The gathering system also includes six processing plants and associated treating facilities with a total capacity of 900,000 Mcfd. During 2007, these plants recovered approximately 54 million gallons of natural gas liquids (NGL's) which were marketed separately from the residue natural gas.

San Juan basin

The San Juan basin is located in northwest New Mexico and southwest Colorado.

Powder River basin

The Powder River basin is located in northeast Wyoming. The Powder River basin includes large areas with multiple coal seam potential, targeting thick coal bed methane formations at shallow depths. We have a significant inventory of undrilled locations, providing long-term drilling opportunities.

Mid-Continent properties

The Mid-Continent properties are located in the southeastern Oklahoma portion of the Arkoma basin and the Barnett Shale in the Fort Worth basin of Texas.

Other properties

Other properties are primarily comprised of interests in the Green River basin in southwestern Wyoming. Also included is exploration activity and other miscellaneous activity.

The following table summarizes our leased acreage as of December 31, 2007:

	Gross Acres	Net Acres
Developed	873,923	447,820
Undeveloped	1,211,865	627,393

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Operating statistics

We focus on lower-risk development drilling. Our drilling success rate was 99 percent in 2007, 2006 and 2005. The following tables summarize domestic drilling activity by number and type of well for the periods indicated:

Number of Wells	Gross Wells	Net Wells
Development:		
Drilled		
2007	1,590	904
2006	1,783	954
2005	1,627	867
Successful		
2007	1,581	899
2006	1,770	948
2005	1,615	859

Because we currently have a low-risk drilling program in proven basins, the main component of risk that we manage is price risk. In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging with the banks and on natural gas reserves value. Exploration & Production natural gas hedges for 2008 domestic natural gas production consist of NYMEX fixed price contracts of 70 MMcf/d (whole year) and approximately 397 MMcf/d in regional collars (whole year). Our natural gas production hedges in 2007 consisted of 172 MMcf/d in NYMEX fixed price hedges and an additional 271 MMcf/d in NYMEX and basin level collars. A collar is an option contract that sets a gas price floor and ceiling for a certain volume of natural gas. Hedging decisions are made considering the overall Williams commodity risk exposure and are not executed independently by Exploration & Production; there are expected future gas purchases for other Williams entities which when taken as a net position may offset price risk related to Exploration & Production's expected future gas sales.

The following table summarizes our domestic sales and cost information for the years indicated:

	2007	2006	2005
Total net production sold (in Bcfe)	333.1	274.4	223.5
Average production costs including production taxes per thousand cubic feet of gas equivalent (Mcfe) produced	$ 0.98	$ 1.02	$ .92
Average sales price per Mcfe	$ 4.92	$ 5.24	$ 6.41
Realized impact of hedging contracts (Loss)	$ 0.16	$ (0.73)	$ (1.61)

Acquisitions & divestitures

Through transactions totaling approximately $77 million, Exploration & Production expanded its acreage position and purchased producing properties in the Fort Worth basin in north-central Texas and also expanded its acreage position in the Highlands area of the Piceance basin.

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production in Peru for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

Other information

In 1993, Exploration & Production conveyed a net profits interest in certain of its properties to the Williams Coal Seam Gas Royalty Trust. Substantially all of the production attributable to the properties conveyed to the trust was from the Fruitland coal formation and constituted coal seam gas. We subsequently sold trust units to the public in an underwritten public offering and retained 3,568,791 trust units then representing 36.8 percent of outstanding trust units. We have previously sold trust units on the open market, with our last sales in June 2005. As of February 1, 2008, we own 789,291 trust units.

International exploration and production interests

We also have investments in international oil and gas interests. If combined with our domestic proved reserves, our international interests would make up approximately 3.6 percent of our total proved reserves.

Gas Pipeline

We own and operate, through Williams Gas Pipeline Company, LLC (WMZ) and its subsidiaries, a combined total of approximately 14,200 miles of pipelines with a total annual throughput of approximately 2,700 trillion British Thermal Units of natural gas and peak-day delivery capacity of approximately 12 MMdt of gas. Gas Pipeline consists of Transcontinental Gas Pipe Line Corporation and Northwest Pipeline GP. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent interest in Gulfstream Natural Gas System, L.L.C. Gas Pipeline also includes our new master limited partnership, Williams Pipeline Partners, L.P.

Transcontinental Gas Pipe Line Corporation (Transco)

Transco is an interstate natural gas transportation company that owns and operates a 10,300-mile natural gas pipeline system extending from Texas, Louisiana, Mississippi and the offshore Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania, and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 11 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, New York, New Jersey, and Pennsylvania.

Pipeline system and customers

At December 31, 2007, Transco's system had a mainline delivery capacity of approximately 4.7 MMdt of natural gas per day from its production areas to its primary markets. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 3.7 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.4 MMdt of natural gas per day. Transco's system includes 45 compressor stations, five underground storage fields, two liquefied natural gas (LNG) storage facilities. Compression facilities at a sea level-rated capacity total approximately 1.5 million horsepower.

Transco's major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco's system include public utilities, municipalities, intrastate pipelines, direct industrial users, electrical generators, gas marketers and producers. One customer accounted for approximately 12 percent of Transco's total revenues in 2007. Transco's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco's business. Additionally, Transco offers storage services and interruptible transportation services under short-term agreements.

Transco has natural gas storage capacity in five underground storage fields located on or near its pipeline system or market areas and operates three of these storage fields. Transco also has storage capacity in an LNG storage facility and operates the facility. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 216 billion cubic feet of gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, an LNG storage facility with 4 billion cubic feet of storage

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capacity. Storage capacity permits Transco's customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Transco expansion projects

The pipeline projects listed below were completed during 2007 or are future pipeline projects for which we have customer commitments.

Potomac Expansion Project

In November 2007, we placed into service the Potomac Expansion Project, an expansion of our existing natural gas transmission system from receipt points in North Carolina to delivery points in the greater Baltimore and Washington, D.C. metropolitan areas. The second phase of the project involving installation of certain appurtenant facilities will be completed in fall 2008. The capital cost of the project is estimated to be approximately $88 million.

Leidy to Long Island Expansion Project

In December 2007, we placed into service the Leidy to Long Island Expansion Project, an expansion of our existing natural gas transmission system in Zone 6 from the Leidy Hub in Pennsylvania to Long Island, New York. The capital cost of the project is estimated to be approximately $169 million.

Sentinel Expansion Project

The Sentinel Expansion Project will involve an expansion of our existing natural gas transmission system from the Leidy Hub in Clinton County, Pennsylvania and from the Pleasant Valley interconnection with Cove Point LNG in Fairfax County, Virginia to various delivery points requested by the shippers under the project. The capital cost of the project is estimated to be up to approximately $169 million. Transco plans to place the project into service in phases, in late 2008 and late 2009.

Pascagoula Expansion Project

The Pascagoula Expansion Project will involve the construction of a new pipeline to be jointly owned with Florida Gas Transmission connecting Transco's existing Mobile Bay Lateral to the outlet pipeline of a proposed liquefied natural gas import terminal in Mississippi. Transco's share of the estimated capital cost of the project is up to $37 million. Transco plans to place the project into service in mid-2011.

Operating statistics

The following table summarizes transportation data for the Transco system for the periods indicated:

	2007	2006	2005
	(In trillion British Thermal Units)		
Market-area deliveries:			
Long-haul transportation	839	795	755
Market-area transportation	875	817	853
Total market-area deliveries	1,714	1,612	1,608
Production-area transportation	190	247	278
Total system deliveries	1,904	1,859	1,886
Average Daily Transportation Volumes	5.2	5.1	5.2
Average Daily Firm Reserved Capacity	6.6	6.6	6.6

Transco's facilities are divided into eight rate zones. Five are located in the production area, and three are located in the market area. Long-haul transportation involves gas that Transco receives in one of the production-area zones and delivers to a market-area zone. Market-area transportation involves gas that Transco both receives and delivers within the market-area zones. Production-area transportation involves gas that Transco both receives and delivers within the production-area zones.

Northwest Pipeline GP (Northwest Pipeline)

Northwest Pipeline is an interstate natural gas transportation company that owns and operates a natural gas pipeline system extending from the San Juan basin in northwestern New Mexico and southwestern Colorado through Colorado, Utah, Wyoming, Idaho, Oregon and Washington to a point on the Canadian border near Sumas, Washington. Northwest Pipeline provides services for markets in California, Arizona, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Oregon and Washington directly or indirectly through interconnections with other pipelines.

Pipeline system and customers

At December 31, 2007, Northwest Pipeline's system, having long-term firm transportation agreements with peaking capacity of approximately 3.4 MMdt of natural gas per day, was composed of approximately 3,900 miles of mainline and lateral transmission pipelines and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 473,000 horsepower.

Northwest implemented new rates effective January 1, 2007 that were approved by FERC. The rate case settlement established that general system firm transportation rates on Northwest's system increased from $0.30760 to $0.40984 per Dth.

In 2007, Northwest Pipeline served a total of 132 transportation and storage customers. Transportation customers include distribution companies, municipalities, interstate and intrastate pipelines, gas marketers and direct industrial users. The two largest customers of Northwest Pipeline in 2007 accounted for approximately 20 percent and 11.5 percent, of its total operating revenues. No other customer accounted for more than 10 percent of Northwest Pipeline's total operating revenues in 2007. Northwest Pipeline's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Northwest Pipeline's business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

As a part of its transportation services, Northwest Pipeline utilizes underground storage facilities in Utah and Washington enabling it to balance daily receipts and deliveries. Northwest Pipeline also owns and operates an LNG storage facility in Washington that provides service for customers during a few days of extreme demands. These storage facilities have an aggregate firm delivery capacity of approximately 600 million cubic feet of gas per day.

Northwest Pipeline expansion projects

The pipeline projects listed below were completed during 2007 or are future pipeline projects for which we have customer commitments.

Jackson Prairie Underground Expansion

The Jackson Prairie Storage Project, connected to Northwest's transmission system near Chehalis, Washington, is operated by Puget Sound Energy and is jointly owned by Northwest, Puget Sound Energy and Avista Corporation. A phased capacity expansion is currently underway and a deliverability expansion is planned for 2008. Northwest's one-third interest in the project includes 104 MMcf per day of planned 2008 deliverability expansion and approximately 1.2 Bcf of working natural gas storage capacity to be developed over approximately a four year period from 2007 through 2010. Northwest's one-third share of the cost of the deliverability expansion is estimated to be $16 million. Northwest's estimated capital cost for the capacity expansion component of the new storage service is $6.1 million, primarily for base natural gas.

Colorado Hub Connection Project

Northwest has proposed installing a new lateral to connect the White River Hub near Meeker, Colorado to Northwest's mainline near Sand Springs, Colorado. This project is referred to as the Colorado Hub

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Connection, or CHC Project. It is estimated that the construction of the CHC Project would cost up to $53 million and could begin service as early as November 2009.

Parachute Lateral

Northwest placed its Parachute Lateral facilities in service on May 16, 2007, and began collecting revenues of approximately $0.87 million per month. The expansion increased capacity by 450 Mdt/d at a cost of approximately $86 million.

On August 24, 2007, Northwest filed an application with FERC to amend its certificate of public convenience and necessity issued for the Parachute Lateral to allow the transfer of the ownership of its Parachute Lateral facilities to a newly created entity, Parachute Pipeline LLC (Parachute), which is owned by Midstream through one of its wholly-owned subsidiaries Williams Field Services Company, LLC (Williams Field Services). This application was approved by FERC on November 15, 2007, and Northwest sold the Parachute on December 31, 2007. The Parachute Lateral facilities are located in Rio Blanco and Garfield counties, Colorado.

As contemplated in the application for amendment, Parachute has leased the facilities back to Northwest, and as a result of the sale has become a Midstream subsidiary. Northwest will continue to operate the facilities under the FERC certificate. When Midstream completes its Willow Creek Processing Plant, the lease (subject to further regulatory approval) will terminate, and Parachute will assume full operational control and responsibility for the Parachute Lateral.

Operating statistics

The following table summarizes volume and capacity data for the Northwest Pipeline system for the periods indicated:

	2007	2006	2005
	(In trillion British Thermal Units)		
Total Transportation Volume	757	676	673
Average Daily Transportation Volumes	2.1	1.9	1.8
Average Daily Reserved Capacity Under Long-Term Base Firm Contracts, excluding peak capacity	2.5	2.5	2.5
Average Daily Reserved Capacity Under Short-Term Firm Contracts(1)	.8	.9	.8

(1) Consists primarily of additional capacity created from time to time through the installation of new receipt or delivery points or the segmentation of existing mainline capacity. Such capacity is generally marketed on a short-term firm basis, because it does not involve the construction of additional mainline capacity.

Gulfstream Natural Gas System, L.L.C. (Gulfstream)

Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. Gas Pipeline and Spectra Energy (formerly known as Duke Energy), through their respective subsidiaries, each holds a 50 percent ownership interest in Gulfstream and provides operating services for Gulfstream. At December 31, 2007, our equity investment in Gulfstream was $439 million.

Gulfstream expansion projects

Gulfstream has entered into a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, Gulfstream intends to extend the pipeline system into South Florida and fully subscribe the remaining 345 Mdt/d of firm capacity on the existing pipeline system on a long-term basis. The estimated capital cost of this project is anticipated to be up to approximately $130 million, with Gas Pipeline's share being 50 percent of such costs. Gulfstream also has executed a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, it intends to construct and fully subscribe on a long-term basis the first incremental expansion of

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Gulfstream's mainline capacity, increasing the current mainline capacity of 1.1 MMdt/d to 1.255 MMdt/d. The estimated capital cost of this expansion is anticipated to be up to approximately $153 million, with Gas Pipeline's share being 50 percent of such costs. No significant increase in operations personnel is expected as a result of these two projects.

Williams Pipeline Partners L.P

WMZ was formed to own and operate natural gas transportation and storage assets. We currently own approximately 45.7 percent limited partnership interest and a 2 percent general partner interest in WMZ. WMZ provides us with lower cost of capital that is expected to enable growth of our Gas Pipeline business. WMZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of Williams and WMZ's general partner, allow us to retain control of the assets through our ownership interest in WMZ. A subsidiary of ours serves as the general partner of WMZ. The initial asset of WMZ is a 35 percent interest in Northwest Pipeline.

Midstream Gas & Liquids

Our Midstream segment, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in the major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico, Venezuela and western Canada. Midstream's primary businesses — natural gas gathering, treating, and processing; NGL fractionation, storage and transportation; and oil transportation — fall within the middle of the process of taking natural gas and crude oil from the wellhead to the consumer. NGLs, ethylene and propylene are extracted/produced at our plants, including our Canadian and Gulf Coast olefins plants. These products are used primarily for the manufacture of plastics, home heating and refinery feedstock.

Although most of our gas services are performed for a volumetric-based fee, a portion of our gas processing contracts are commodity-based and include two distinct types of commodity exposure. The first type includes "Keep Whole" processing contracts whereby we own the rights to the value from NGLs recovered at our plants and have the obligation to replace the lost heating value with natural gas. Under these contracts, we are exposed to the spread between NGLs and natural gas prices. The second type consists of "Percent of Liquids" contracts whereby we receive a portion of the extracted liquids with no direct exposure to the price of natural gas. Under these contracts, we are only exposed to NGL price movements.

Our Canadian and Gulf Liquids olefin facilities have commodity price exposure. In Canada, we are exposed to the spread between the price for natural gas and the olefinic products we produce. In the Gulf Coast, our feedstock for the ethane cracker is ethane and propane; as a result, we are exposed to the price spread between ethane and propane and ethylene and propylene. In the Gulf Coast, we also purchase refinery grade propylene and fractionate it into polymer grade propylene and propane; as a result we are exposed to the price spread between those commodities.

Key variables for our business will continue to be:

- retaining and attracting customers by continuing to provide reliable services;
- revenue growth associated with additional infrastructure either completed or currently under construction;
- disciplined growth in our core service areas;
- prices impacting our commodity-based processing and olefin activities.

Gathering and processing

We own and/or operate domestic gas gathering and processing assets primarily within the western states of Wyoming, Colorado and New Mexico, and the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi and Alabama. These assets consist of approximately 8,700 miles of gathering pipelines, nine processing plants (one partially owned) and five natural gas treating plants with a combined daily inlet capacity of nearly 6.5 billion cubic feet per day. Some of these assets are owned through our interest in WPZ (see William Partners L.P. section below).

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Geographically, our Midstream natural gas assets are positioned to maximize commercial and operational synergies with our other assets. For example, most of our offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Also, our gathering and processing facilities in the San Juan Basin handle about 85 percent of our Exploration & Production group's wellhead production in this basin. Both our San Juan Basin and Southwest Wyoming systems deliver gas volumes into Northwest Pipeline's interstate system in addition to third party interstate systems.

Included in the natural gas assets listed above are the assets of Discovery Producer Services LLC and its subsidiary Discovery Gas Transmission Services LLC (Discovery). WPZ owns a partial interest in Discovery and we operate its facilities. Discovery's assets include a cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana and an offshore natural gas gathering and transportation system in the Gulf of Mexico.

In addition to these natural gas assets, we own and operate three crude oil pipelines totaling approximately 310 miles with a capacity of more than 300,000 barrels per day. This includes our Mountaineer, Alpine and BANJO crude oil pipeline systems in the deepwater Gulf of Mexico.

The BANJO oil pipeline and Seahawk gas pipeline run parallel and deliver production across two producer-owned spar-type floating production systems from the Anadarko Petroleum Corporation (Anadarko) operated Boomvang and Nansen field areas in the western Gulf of Mexico. These pipelines were placed in service in 2002.

Our 18 inch oil pipeline, Alpine, which became operational in 2003, is our second western gulf crude oil pipeline. The pipeline extends 96 miles from Garden Banks Block 668 in the central Gulf of Mexico to our shallow-water platform at Galveston Area Block A244. From this platform, the oil is delivered onshore through ExxonMobil's Hoover Offshore Oil Pipeline System under a joint tariff agreement. This production is coming from the Gunnison field, which is located in 3,150 feet of water and operated by Anadarko.

Our Devils Tower floating production system and associated pipelines were placed in service in 2004. Initially built to serve the Devils Tower field, the floating production system is located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama. During the fourth quarter of 2005, the platform's service expanded to include tie-backs of production from the Triton and Goldfinger fields in addition to the host Devils Tower field. Construction is currently underway to add topside capacity for the recently dedicated Bass Lite gas discovery. Full field production from Bass Lite is expected mid-year 2008. Located in 5,610 feet of water, it is the world's deepest dry tree spar. The platform, which is operated by ENI Petroleum on our behalf, is capable of producing 60 MMcf/d of natural gas and 60 Mbbls/d of oil.

The Devils Tower project includes gas and oil pipelines. The 139-mile Canyon Chief gas pipeline consists of 18-inch diameter pipe. The 155-mile Mountaineer oil pipeline is a combination of 18- and 20-inch diameter pipe. The gas is delivered into Transco's pipeline, and processed at our Mobile Bay plant to recover the NGLs. The oil is transported to ChevronTexaco's Empire Terminal in Plaquemines Parish, Louisiana. These associated pipelines are significantly oversized relative to the Devils Tower spar top-side capacity.

Gulf Coast petrochemical and olefins

We own a 10/12 interest in and are the operator for an ethane cracker at Geismar, Louisiana, with a total production capacity of 1.3 billion pounds per year of ethylene. In July 2007, we exercised our right of first refusal to acquire BASF's 5/12 th ownership interest in the Geismar olefins facility bringing our ownership position up to the current 10/12 interest. We also own an ethane pipeline system and a propylene splitter and its related pipeline system in Louisiana.

Canada

Our Canadian operations include an olefin liquids extraction plant located near Ft. McMurray, Alberta and an olefin fractionation facility near Edmonton, Alberta. Our facilities extract olefinic liquids from the off-gas produced from third party oil sands bitumen upgrading and then fractionate, treat, store, terminal and sell the propane, propylene, butane and condensate recovered from this process. We continue to be the only olefins fractionator in Western Canada and the only treater-processor of oil sands upgrader off-gas. These operations extract valuable petrochemical feedstocks from upgrader off-gas streams allowing the upgraders to burn cleaner natural gas streams and reduce overall air emissions. The extraction plant has processing capacity in excess of 100 MMcf/d with the ability to recover in excess of 15 Mbbls/d of olefin and NGL products.

Venezuela

Our Venezuelan investments involve gas compression and gas processing and natural gas liquids fractionation operations. We own controlling interests and operate three gas compressor facilities which provide roughly 70 percent of the gas injections in eastern Venezuela. These facilities help stabilize the reservoir and enhance the recovery of crude oil by re-injecting natural gas at high pressures. We also own a 49.25 percent interest in two 400 MMcf/d natural gas liquids extraction plants, a 50,000 barrels per day natural gas liquids fractionation plant and associated storage and refrigeration facilities.

Other

We own interests in and/or operate NGL fractionation and storage assets. These assets include two partially owned NGL fractionation facilities near Conway, Kansas and Baton Rouge, Louisiana that have a combined capacity in excess of 167,000 barrels per day. We also own approximately 20 million barrels of NGL storage capacity in central Kansas. Some of these assets are owned through our interest in WPZ.

We also own a 14.6% interest in Aux Sable Liquid Products and its Channahon, Illinois gas processing and NGL fractionation facility near Chicago. The facility is capable of processing up to 2.1 Bcf/d of natural gas from the Alliance Pipeline system and fractionating approximately 87,000 barrels per day of extracted liquids into NGL products.

Williams Partners L.P (WPZ)

WPZ was formed to engage in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. We currently own approximately a 21.6 percent limited partnership interest and a 2 percent general partner interest in WPZ. WPZ provides us with lower cost of capital that is expected to enable growth of our Midstream business. WPZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of both Williams and WPZ's general partner, allow us to retain control of the assets through our ownership interest in WPZ.

WPZ's asset portfolio at its initial public offering in 2005 consisted of a 40 percent interest in Discovery, the Carbonate Trend gathering pipeline, three integrated NGL storage facilities near Conway, Kansas and a 50 percent interest in an NGL fractionator near Conway, Kansas.

During 2006, WPZ acquired Williams Four Corners, LLC which owns a 3,500-mile natural gas gathering system in the San Juan Basin in New Mexico and Colorado with capacity of nearly 2 Bcf/d; the Ignacio natural gas processing plant in Colorado and the Kutz and Lybrook natural gas processing plants in New Mexico, which have a combined processing capacity of 760 MMcf/d; and the Milagro and Esperanza natural gas treating plants in New Mexico, which are designed to remove carbon dioxide from up to 750 MMcf of natural gas per day.

In June 2007, WPZ acquired an additional 20 percent interest in Discovery. WPZ now owns a 60 percent interest in the Discovery gathering, transportation, processing and NGL fractionation system, the remainder of which is owned by third parties.

In December 2007, WPZ acquired certain ownership interests in Wamsutter LLC from us for $750 million. Wamsutter LLC owns a 1,700 mile natural gas gathering system in the Washakie Basin in south-central Wyoming and the Echo Springs natural gas processing plant in Sweetwater County, Wyoming.

Expansion projects

Gathering and processing — west

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1.5 Bcf/d. This plant expansion increased Opal's processing capacity by more than 30 percent and became operational during the first quarter.

In the first quarter of 2007, we also announced plans to construct and operate the Willow Creek facility a 450 MMcf/d natural gas processing plant in the Piceance Basin of western Colorado, where Exploration and Production has its most significant volume of natural gas production, reserves and development activity. Exploration and Production's existing Piceance Basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

In December 2007, Midstream purchased the Parachute Lateral system from Gas Pipeline. The system is a 37.6-mile expansion, originally placed in service by Gas Pipelines in May 2007, and provides capacity of 450 Mdt/d through a 30-inch diameter line, transporting residue gas from the Piceance basin to the Greasewood Hub in northwest Colorado. The Willow Creek facility will straddle the Parachute Lateral pipeline and will process gas flowing through the pipeline. In an arrangement approved by the FERC, Midstream will lease the pipeline to Gas Pipeline, who will continue to operate the pipeline until completion of a planned FERC abandonment filing.

In addition, Midstream acquired an existing natural gas pipeline from Gas Pipeline, and has begun the process of converting it from natural gas to NGL service and constructing additional pipeline to create a pipeline alternative for NGLs currently being transported by truck from Exploration & Production's existing Piceance basin processing plants to a major NGL transportation pipeline system.

In 2006, we entered into an agreement to develop new pipeline capacity for transporting NGLs from production areas in southwestern Wyoming to central Kansas. The other party to the agreement reimbursed us for the development costs we had incurred for the proposed pipeline and acquired 99 percent of the pipeline, known as Overland Pass Pipeline Company, LLC. We retained a 1 percent interest and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for mid-2008. Additionally, we have agreed to dedicate our equity NGL volumes from our two Wyoming plants and the new Willow Creek facility for transport under a long-term shipping agreement. The terms represent significant savings compared with the existing tariff and other alternatives considered.

Gathering and processing — deepwater projects

The deepwater Gulf continues to be an attractive growth area for our Midstream business. Since 1997, we have invested almost $1.3 billion in new midstream assets in the Gulf of Mexico. These facilities provide both onshore and offshore services through pipelines, platforms and processing plants. The new facilities could also attract incremental gas volumes to Transco's pipeline system in the southeastern United States.

During 2007, we have continued construction activities on the Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. In addition, we completed agreements with certain producers to provide gathering, processing and transportation services over the life of the reserves. We also intend to expand our onshore Markham gas processing facility to adequately serve this new gas production. The scale of the project has increased to include additional pipeline and more efficient processing capacity and is now estimated to cost approximately $560 million and to be in service in the third quarter of 2009.

Chevron and Anadarko are dedicating to us the transport of production from their current and future ownership in a defined area surrounding the Blind Faith discovery in the deepwater Gulf of Mexico. To accommodate production from the Blind Faith acreage and the surrounding blocks, we have agreed to extend our Canyon Chief and Mountaineer pipelines to the producer-owned floating production facility. We expect to have the extensions ready for service in the second quarter of 2008. The approximately $250 million project will facilitate a 37-mile extension of each pipeline. The agreement also creates opportunities for us to move natural gas from the Blind Faith discovery through our Mobile Bay, Alabama, processing plant and our Transco and Gulfstream interstate pipeline systems. Recovered NGLs from Blind Faith also could be fractionated at our facilities in Baton Rouge or Paradis, Louisiana.

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Customers and operations

Our domestic gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding our infrastructure. During 2007, these operations gathered and processed gas for approximately 215 gas gathering and processing customers. Our top three gathering and processing customers accounted for about 45 percent of our domestic gathering and processing revenue. Our gathering and processing agreements are generally long-term agreements.

In addition to our gathering and processing operations, we market NGLs and petrochemical products to a wide range of users in the energy and petrochemical industries. We provide these products to third parties from the production at our domestic facilities. The majority of domestic sales are based on supply contracts of less than one year in duration. The production from our Canadian facilities is marketed in Canada and in the United States.

Our Venezuelan assets were constructed and are currently operated for the exclusive benefit of Petróleos de Venezuela S.A under long-term contracts. These significant contracts have a remaining term between 10 and 14 years and our revenues are based on a combination of fixed capital payments, throughput volumes, and, in the case of one of the gas compression facilities, a minimum throughput guarantee. The Venezuelan government has continued its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and continues to publicly declare that additional energy contracts will be unilaterally amended and privately held assets will be expropriated, escalating our concern regarding political risk in Venezuela.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2007	2006	2005
Volumes(1):			
Domestic Gathering (trillion British Thermal Units)	1,045	1,181	1,253
Domestic Natural Gas Liquid Production (Mbbls/d)(2)	163	152	144
Crude Oil Gathering (Mbbls/d)(2)	80	86	88
Processing Volumes (trillion British Thermal Units)	937	833	721

(1) Excludes volumes associated with partially owned assets that are not consolidated for financial reporting purposes.

(2) Annual Average Mbbls/d

Gas Marketing Services

Gas Marketing Services primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third-parties, such as producers.

Gas Marketing Services' natural gas sales volumes, including sales volumes to other segments, were 2.3 Bcf/d, 2.1 Bcf/d and 2.1 Bcf/d for the years ending December 31, 2007, 2006 and 2005, respectively. Gas Marketing Services' natural gas purchase volumes, including purchases from other segments, were 2.4 Bcf/d, 2.3 Bcf/d and 2.2 Bcf/d for the same periods.

As of December 31, 2007, Gas Marketing Services has approximately 159 customers compared with approximately 163 customers at the end of 2006.

Our Exploration and Production and Midstream segments may execute commodity hedges with Gas Marketing Services. In turn, Gas Marketing Services may execute offsetting derivative contracts with unrelated third parties.

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As a result of the sale of a substantial portion of our Power business in the fourth quarter of 2007, Gas Marketing Services also is responsible for certain remaining legacy natural gas contracts and positions. We intend to liquidate a substantial portion of these legacy contracts. During 2007, we substantially reduced the overall legacy positions remaining. Until such legacy positions are liquidated, segment results may experience mark- to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting. However, this mark-to-market volatility is expected to be significantly reduced compared to previous levels.

Other

At December 31, 2007, we owned approximately 99.3 percent of the Class B Interests in Longhorn Partners Pipeline LP (Longhorn), which owned a refined petroleum products pipeline from Houston, Texas to El Paso, Texas. The Class B Interests are preferred interests but subordinate to other preferred interests, and the common interests are subordinate to both. It is uncertain whether we will ever receive any payments related to our Class B Interests or our common interests, however any such amounts related to these interests were fully impaired in 2005, and will only be recognized as income when received.

We continue to receive payments associated with the 2005 transfer of the First Amended and Restated Pipeline Operating Services Agreement to a third party. The management of Longhorn completed an installment sale of the pipeline during the third quarter of 2006. The sale of the pipeline did not impact these ongoing payments which are recognized as income when received.

Additional Business Segment Information

Our ongoing business segments are accounted for as continuing operations in the accompanying financial statements and notes to financial statements included in Part II.

Operations related to certain assets in "Discontinued Operations" have been reclassified from their traditional business segment to "Discontinued Operations" in the accompanying financial statements and notes to financial statements included in Part II.

Our corporate parent company performs certain management, legal, financial, tax, consultative, information technology, administrative and other services for our subsidiaries.

Our corporate parent company's principal sources of cash are from external financings, dividends and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, sales of master partnership units to the public, interest payments from subsidiaries on cash advances and net proceeds from asset sales. The amount of dividends available to us from subsidiaries largely depends upon each subsidiary's earnings and operating capital requirements. The terms of certain of our subsidiaries' borrowing arrangements limit the transfer of funds to our corporate parent.

We believe that we have adequate sources and availability of raw materials and commodities for existing and anticipated business needs. In support of our energy commodity activities, primarily conducted through Gas Marketing Services, our counterparties require us to provide various forms of credit support such as margin, adequate assurance amounts and pre-payments for gas supplies. Our pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory agencies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

REGULATORY MATTERS

Exploration & Production. Our Exploration & Production business is subject to various federal, state and local laws and regulations on taxation and payment of royalties, and the development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 17. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Our master limited partnership, Williams Partners L.P., is consolidated within our Midstream segment. (See Note 1.) Other primarily consists of corporate operations.

Performance Measurement

We currently evaluate performance based on *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses, depreciation, depletion and amortization, equity earnings (losses)* and *loss from investments* including impairments related to investments accounted for under the equity method. The accounting policies of the segments are the same as those described in Note 1. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Energy commodity hedging by our business units may be done through intercompany derivatives with our Gas Marketing Services segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Gas Marketing Services bears the counterparty performance risks associated with the unrelated third parties in these transactions. Additionally, beginning in the first quarter of 2007, hedges related to Exploration & Production may be entered into directly between Exploration & Production and third parties under its new credit agreement. (See Note 11.) Exploration & Production bears the counterparty performance risks associated with the unrelated third parties in these transactions.

Gas Marketing Services primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third parties, such as producers.

External revenues of our Exploration & Production segment includes third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

The following geographic area data includes *revenues from external customers* based on product shipment origin and *long-lived assets* based upon physical location.

	United States	Other (Millions)	Total
Revenues from external customers:			
2007	$ 10,137	$ 421	$10,558
2006	8,982	394	9,376
2005	9,466	315	9,781
Long-lived assets:			
2007	$ 16,279	$ 713	$16,992
2006	14,487	682	15,169
2005	12,667	740	13,407

Our foreign operations are primarily located in Venezuela, Canada, and Argentina. *Long-lived assets* are comprised of property, plant and equipment, goodwill and other intangible assets.

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Income and *other financial information* related to *long-lived assets*.

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
2007							
Segment revenues:							
External	$ (95)	$ 1,576	$ 5,142	$ 3,924	$ 11	$ —	$10,558
Internal	2,188	34	38	709	15	(2,984)	—
Total revenues	$ 2,093	$ 1,610	$ 5,180	$ 4,633	$ 26	$ (2,984)	$10,558
Segment profit (loss)	$ 756	$ 673	$ 1,072	$ (337)	$ (1)	$ —	$ 2,163
Less equity earnings	25	51	61	—	—	—	137
Segment operating income (loss)	$ 731	$ 622	$ 1,011	$ (337)	$ (1)	$ —	2,026
General corporate expenses							(161)
Total operating income							$ 1,865
Other financial information:							
Additions to long-lived assets	$ 1,717	$ 546	$ 610	$ —	$ 27	$ —	$ 2,900
Depreciation, depletion & amortization	$ 535	$ 315	$ 214	$ 7	$ 10	$ —	$ 1,081
2006							
Segment revenues:							
External	$ (189)	$ 1,336	$ 4,094	$ 4,128	$ 7	$ —	$ 9,376
Internal	1,677	12	65	921	20	(2,695)	—
Total revenues	$ 1,488	$ 1,348	$ 4,159	$ 5,049	$ 27	$ (2,695)	$ 9,376
Segment profit (loss)	$ 552	$ 467	$ 675	$ (195)	$ (13)	$ —	$ 1,486
Less equity earnings	22	37	40	—	—	—	99
Segment operating income (loss)	$ 530	$ 430	$ 635	$ (195)	$ (13)	$ —	1,387
General corporate expenses							(132)
Securities litigation settlement and related costs							(167)
Total operating income							$ 1,088
Other financial information:							
Additions to long-lived assets	$ 1,496	$ 913	$ 279	$ 1	$ 18	$ —	$ 2,707
Depreciation, depletion & amortization	$ 360	$ 282	$ 203	$ 7	$ 11	$ —	$ 863
2005							
Segment revenues:							
External	$ (202)	$ 1,395	$ 3,212	$ 5,366	$ 10	$ —	$ 9,781
Internal	1,471	18	79	969	17	(2,554)	—
Total revenues	$ 1,269	$ 1,413	$ 3,291	$ 6,335	$ 27	$ (2,554)	$ 9,781
Segment profit (loss)	$ 587	$ 586	$ 460	$ 9	$ (123)	$ —	$ 1,519
Less:							
Equity earnings (losses)	19	44	27	—	(24)	—	66
Loss from investments	—	—	(22)	—	(87)	—	(109)
Segment operating income (loss)	$ 568	$ 542	$ 455	$ 9	$ (12)	$ —	1,562
General corporate expenses							(145)
Securities litigation settlement and related costs							(9)
Total operating income							$ 1,408
Other financial information:							
Additions to long-lived assets	$ 795	$ 420	$ 133	$ 6	$ 5	$ —	$ 1,359
Depreciation, depletion & amortization	$ 254	$ 267	$ 194	$ 10	$ 12	$ —	$ 737

THE WILLIAMS COMPANIES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table reflects *total assets* and *equity method investments* by reporting segment.

	Total Assets			Equity Method Investments		
	December 31, 2007	December 31, 2006	December 31, 2005	December 31, 2007	December 31, 2006	December 31, 2005
			(Millions)			
Exploration & Production(1)	$ 8,692	$ 7,851	$ 8,672	$ 72	$ 59	$ 58
Gas Pipeline	8,624	8,332	7,581	483	432	439
Midstream Gas & Liquids	6,604	5,562	4,772	321	323	333
Gas Marketing Services(2)	4,437	5,519	11,464	—	—	—
Other	3,592	3,923	3,571	—	—	1
Eliminations(3)	(7,073)	(7,187)	(10,109)	—	—	—
	24,876	24,000	25,951	876	814	831
Discontinued operations	185	1,402	3,492	—	—	—
Total	$ 25,061	$ 25,402	$ 29,443	$ 876	$ 814	$ 831

(1) The 2006 decrease in Exploration & Production's total assets is due primarily to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing derivative contracts. Exploration & Production's derivatives are primarily comprised of intercompany transactions with the Gas Marketing Services segment.

(2) The decrease in Gas Marketing Services' total assets for both 2007 and 2006 is due primarily to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Gas Marketing Services' derivative assets are substantially offset by their derivative liabilities.

(3) The 2006 decrease in Eliminations is due primarily to the fluctuations in the intercompany derivative balances.

Note 18. Subsequent Events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ including the interests of the general partner. In accordance with EITF Issue No. 04-5 (see Note 1), WMZ will continue to be consolidated within our Gas Pipeline segment due to our control through the general partner, which is wholly owned by us.

At December 31, 2007, we held all of Williams Partners L.P.'s seven million subordinated units outstanding. In February 2008, all of these subordinated units were converted into common units due to factors which resulted in the termination of the subordination period. As a result, we will recognize a decrease to minority interest and a corresponding increase to stockholders' equity of approximately $1.2 billion in the first quarter of 2008.