Dorchester Hugoton, Ltd. (DHULZ - 8.88)
Enhancement Underway

Summary and Conclusion

The units of Dorchester Hugoton appear to have appreciation potential in addition to offering high current income with inflation protection and tax advantage. Long awaited fracturing and deeper drilling are underway to boost reserves in the partnership's fifty-year-old properties. Fracturing the formation around an old well may almost be the equivalent of adding another average well in production and reserves. More than 80% of the partnership's wells remain to be fracture treated. Meanwhile financial risk is low because the partnership has no debt. In fact it holds cash and marketable securities potentially available to support rising distributions. Size risk is high with only 10.7 million units outstanding. The founding and continuing general partner, age 77, holds 15% of the units.

Present Value Discounts Future Cash Flows

Our calculations give a present value of the partnership’s reserves of $11.40 a unit (see file Dhulz0128.xls, tab Asset Value). The greatest uncertainty, at least relatively, is the amount of enhancement volume that can be achieved and at what cost. We will explain the analysis by order of columns in the calculation from left to right.

<u>Volume Projections Anticipate Decline and Enhancement</u>

Natural gas production from existing producing wells is projected to decline at 11% per year for 30 years cumulating to almost 10 times 1999 production (see Table DHULZ-1). Kansas production, some 20% of total, declined more steeply last year.

We project an 8% per year enhancement to production stemming the decline to a net 3%. That is about what was achieved in Oklahoma through nine months last year. Enhancement adds 44 bcf of production in 30 years to the 65 bcf from existing capacity.

The total of 109 bcf is 16 times 1999 production, not a conservative number in the context of proven reserves. Yet in light of the history of the Hugoton field and in view of specific sources of untapped potential the projection seems reasonable in economic value.

If fracturing continues to be successful, it could account for the enhancement we project. In addition, the partnership has deeper drilling potential. Early results to the deeper Ft. Riley zone in the Chase formation have been mixed. Continuing activity by others to the deeper Council Grove formation seem more promising, but not without frustration.

Price Projection Matches Inflation

After 2000, natural gas price escalates at 3% per year, only slightly more than the 2.1% per year implied by the difference in yield for U.S. Treasury bonds and U.S. Treasury Inflation Protected Securities. Considering that demand for natural gas as a clean fuel is strong and that producers of the commodity have not earned an economic return on new investment for the past ten years, a case could be made that natural gas price should readjust upward. Yet the trend of commodity price has been weak in the high productivity, technologically super-charged economy of recent years.

Operating and Investment Costs Low

A frugal operator of its own properties, the partnership incurs lower operating costs than its namesake royalty trust, for example. Moreover the cost of its enhancement effort so far is well below our projected levels. Yet as time goes on cost will rise. When it is necessary to add compressors to boost production, costs go up. Fracturing effectiveness is not easily predictable. Drilling will be more expensive than fracturing.

Discount at 8% Per Year

Finally we multiply annual cash flows by the discount factor and add them up to derive present value. The discount factor is the discount rate applied for the appropriate time period. For the year 2000, the discount rate of 8% is applied for a half year, assuming that all the cash flow is received at mid year. For the year 2001, the rate is applied for a year and a half and so on. The rate represents a premium to the “risk-free” government rate, but is not as high as would be paid by low-grade borrowers.

Sensitivity Illustrates Upside

It is no surprise that current stock price reflects conventional knowledge about the future. What if conditions were different than those projected. For example, suppose existing production declines at 9% as we project for the San Juan Basin rather than 11% as we project for the partnership. Go to cell E5 in the present value model and type in 9. Press Enter and see cell M14 change from 11.40 to 13.50.

The partnership is also a straightforward play on long-term natural gas price. Suppose overnight the expected price for 2000 would be $1.00 per mcf higher. Go to cell E18 and type in 3.57. Press Enter and see cell M14 change from 11.40 to 15.80.

Income Model Projects Cash Flow in Excess of Distributions

Unlike royalty trusts that are required to distribute all free cash flow, limited partnerships have discretion. Managed conservatively, Dorchester Hugoton makes distributions that are still hefty, but more than covered by free cash flow (see file Dhulz0128.xls, tab Quarterly Income). As a result we would expect the partnership to be priced at a lower Dynamic Distribution Yield than a royalty trust with identical properties and identical current reinvestment. While we do not project an increase in distribution in 2000, that is a discretionary decision that could readily be made.

We do project a higher cash flow in 2000 with the gain over 1999 primarily in the first half. True, the futures market projects a decline in the higher commodity price recently achieved. Yet the comparisons with last year in the next several months are likely to continue positive. The income model is updated weekly for oil and gas futures prices, quarterly for interim disclosure and annually for more complete disclosure.

By definition our price projection is that of the consensus, the futures market. The differential between Henry Hub, the pricing point for futures, and what the partnership receives is our estimate.

Our natural gas volume projection for 2000 incorporates a decline of 1% per quarter from 17 million cubic feet per day (mmcfd) for the first quarter 2000. That implies current gross operating volumes of some 20 mmcfd before one-eighth royalty and fuel consumption. We'll know in a few weeks what the partnership discloses for its fourth quarter 1999 volume.

We expect fourth quarter details when the partnership files its 10-K annual report with the Securities and Exchange Commission. Last year the filing was on February 12.

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N.B. The original version of this analysis was posted on the site referenced in the footnote below in separate text and spreadsheet files. When combining the tables and text in the same document for belated posting on mcdep.com, the tables were converted to pdf pages. As a result the interactivity encouraged above under the heading "Sensitivity Illustrates Upside" only works on the files posted originally.

Table DHULZ-1
Dorchester Hugoton, Ltd.
Present Value

Volume Decline (%/yr):	11	Price Escalation (%/yr):	3
Volume Enhancement (%/yr):	8	Variable Cost (%):	13
Capex/Cash Flow (%):	15	Discount rate (%/yr):	8

Year	Basic (bcf)	Volume Enhanced (bcf)	Total (bcf)	Price ($/mcf)	Revenue ($mm)	Fixed Cost ($mm)	Var Cost ($mm)	Cap Ex ($mm)	Cash Flow ($mm)	Cash Flow ($/unit)	Disc Factor	Present Value ($/unit)
Total 2000 through 2029												
	65	44	108	3.57	387	60	50	26	250	23.32	0.49	11.40
1999	6.8		6.8	2.25	15.3	2.5	2.0	0.4	10.4	0.97		
						Working Capital			9.0	0.84	1.00	0.84
2000	6.8	-0.7	6.1	2.57	15.7	2.0	2.0	0.4	11.2	1.05	0.96	1.01
2001	6.0	-0.1	5.9	2.65	15.7	2.0	2.0	1.7	9.9	0.92	0.89	0.82
2002	5.4	0.4	5.8	2.73	15.9	2.0	2.1	1.8	10.0	0.93	0.82	0.77
2003	4.9	0.8	5.7	2.81	16.0	2.0	2.1	1.8	10.1	0.94	0.76	0.72
2004	4.4	1.2	5.6	2.89	16.1	2.0	2.1	1.8	10.2	0.95	0.71	0.67
2005	4.0	1.5	5.5	2.98	16.3	2.0	2.1	1.8	10.3	0.96	0.65	0.63
2006	3.6	1.8	5.3	3.07	16.4	2.0	2.1	1.8	10.4	0.97	0.61	0.59
2007	3.2	2.0	5.2	3.16	16.5	2.0	2.1	1.9	10.5	0.98	0.56	0.55
2008	2.9	2.2	5.1	3.25	16.6	2.0	2.2	1.9	10.6	0.98	0.52	0.51
2009	2.6	2.4	5.0	3.35	16.7	2.0	2.2	1.9	10.6	0.99	0.48	0.48
2010	2.4	2.5	4.9	3.45	16.8	2.0	2.2	1.9	10.7	1.00	0.45	0.44
2011	2.1	2.6	4.7	3.56	16.8	2.0	2.2	1.9	10.8	1.00	0.41	0.41
2012	1.9	2.7	4.6	3.66	16.9	2.0	2.2	1.9	10.8	1.01	0.38	0.38
2013	1.7	2.8	4.5	3.77	17.0	2.0	2.2	1.9	10.9	1.01	0.35	0.36
2014	1.6	2.8	4.4	3.89	17.0	2.0	2.2	1.9	10.9	1.02	0.33	0.33
2015	1.4	2.5	3.9	4.00	15.7	2.0	2.0		11.6	1.08	0.30	0.33
2016	1.3	2.2	3.5	4.12	14.4	2.0	1.9		10.6	0.98	0.28	0.28
2017	1.1	2.0	3.1	4.25	13.3	2.0	1.7		9.6	0.89	0.26	0.23
2018	1.0	1.8	2.8	4.37	12.2	2.0	1.6		8.7	0.81	0.24	0.19
2019	0.9	1.6	2.5	4.50	11.3	2.0	1.5		7.8	0.73	0.22	0.16
2020	0.8	1.4	2.2	4.64	10.4	2.0	1.3		7.0	0.65	0.21	0.14
2021	0.7	1.3	2.0	4.78	9.6	2.0	1.2		6.3	0.59	0.19	0.11
2022	0.7	1.1	1.8	4.92	8.8	2.0	1.1		5.7	0.53	0.18	0.09
2023	0.6	1.0	1.6	5.07	8.1	2.0	1.1		5.1	0.47	0.16	0.08
2024	0.5	0.9	1.4	5.22	7.5	2.0	1.0		4.5	0.42	0.15	0.06
2025	0.5	0.8	1.3	5.38	6.9	2.0	0.9		4.0	0.37	0.14	0.05
2026	0.4	0.7	1.1	5.54	6.3	2.0	0.8		3.5	0.33	0.13	0.04
2027	0.4	0.6	1.0	5.71	5.8	2.0	0.8		3.1	0.29	0.12	0.03
2028	0.4	0.6	0.9	5.88	5.4	2.0	0.7		2.7	0.25	0.11	0.03
2029	0.3	0.5	0.8	6.05	5.0	2.0	0.6		2.3	0.21	0.10	0.02

Table DHULZ-2
Dorchester Hugoton, Ltd.
Income Model

	Year 1998	*Q1 3/31/99*	*Q2 6/30/99*	*Q3 9/30/99*	*Q4E 12/31/99*	*Year 1999E*	*Q1E 3/31/00*	*Q2E 6/30/00*	*Q3E 9/30/00*	*Q4E 12/31/00*	*Year 2000E*
Highlights											
Revenue ($mm)	15.37	3.06	3.51	4.34	3.85	14.8	3.77	3.70	3.74	3.91	15.1
Cash flow ($mm)	11.02	2.09	2.35	3.25	2.76	10.4	2.80	2.73	2.77	2.95	11.2
Per unit	1.03	0.19	0.22	0.30	0.26	0.97	0.26	0.25	0.26	0.27	1.05
Earnings ($mm)	9.01	1.60	1.89	2.77	2.28	8.5	2.37	2.30	2.34	2.52	9.5
Per unit	0.84	0.15	0.18	0.26	0.21	0.80	0.22	0.21	0.22	0.23	0.89
Distribution ($mm)	7.74	1.93	1.93	1.93	1.93	7.7	1.93	1.93	1.93	1.93	7.7
Per unit	0.72	0.18	0.18	0.18	0.18	0.72	0.18	0.18	0.18	0.18	0.72
Units (millions)	10.74	10.74	10.74	10.74	10.74	10.7	10.74	10.74	10.74	10.74	10.7
Volume											
Natural gas (bcf)											
Oklahoma	5.74	1.42	1.33	1.40	1.32	5.5	1.24	1.24	1.24	1.23	4.9
Kansas	1.70	0.35	0.34	0.33	0.31	1.3	0.29	0.29	0.29	0.29	1.2
Total	7.44	1.76	1.67	1.72	1.63	6.8	1.53	1.53	1.53	1.52	6.1
Natural Gas (mmcfd)	20.4	19.6	18.4	18.7	17.7	18.6	17.0	16.8	16.7	16.5	16.7
Days	365	90	91	92	92	365	90	91	92	92	365
Price											
Natural gas											
Henry Hub ($/mmbtu)		1.79	2.22	2.52	2.45	2.24	2.55	2.50	2.53	2.67	2.56
Oklahoma ($/mcf)	2.11	1.77	2.15	2.60	2.44	2.24	2.54	2.49	2.52	2.66	2.55
Kansas ($/mcf)	2.22	1.85	2.26	2.68	2.52	2.32	2.62	2.57	2.60	2.74	2.63
Total ($/mcf)	2.14	1.79	2.17	2.62	2.46	2.25	2.56	2.51	2.53	2.68	2.57
Revenue ($mm)											
Natural Gas											
Oklahoma	12.11	2.50	2.87	3.63	3.22	12.2	3.14	3.08	3.12	3.27	12.6
Kansas	3.77	0.64	0.76	0.88	0.78	3.1	0.77	0.76	0.76	0.80	3.1
Other	0.23	0.05	0.05	0.05	0.05	0.2	0.05	0.05	0.05	0.05	0.2
Production payment (ORRI)	(0.73)	(0.14)	(0.17)	(0.22)	(0.20)	(0.7)	(0.20)	(0.19)	(0.19)	(0.20)	(0.8)
Total	15.37	3.06	3.51	4.34	3.85	14.8	3.77	3.70	3.74	3.91	15.1
Cost ($mm)											
Operating	3.54	0.79	0.96	0.90	0.90	3.5	0.78	0.78	0.78	0.77	3.1
General and administrative	0.53	0.14	0.13	0.14	0.14	0.5	0.14	0.14	0.14	0.14	0.6
Management	0.49	0.12	0.12	0.13	0.13	0.5	0.13	0.13	0.13	0.13	0.5
Other	(0.22)	(0.06)	(0.05)	(0.08)	(0.08)	(0.3)	(0.08)	(0.08)	(0.08)	(0.08)	(0.3)
Total	4.35	0.98	1.16	1.09	1.09	4.3	0.97	0.97	0.97	0.96	3.9
Cash flow ($mm)	11.02	2.09	2.35	3.25	2.76	10.4	2.80	2.73	2.77	2.95	11.2
Depletion, deprec. & amort.	2.02	0.49	0.46	0.48	0.48	1.9	0.43	0.43	0.43	0.42	1.7
Earnings ($mm)	9.01	1.60	1.89	2.77	2.28	8.5	2.37	2.30	2.34	2.52	9.5
Capital expenditures ($mm)	1.14	0.04	0.05	0.21	0.06	0.4	0.10	0.10	0.10	0.10	0.4
Modeling ratios											
Prod pay/revenue	4.6%	4.3%	4.5%	4.9%	5.0%	4.7%	5.0%	5.0%	5.0%	5.0%	5.0%
Operating cost ($/mcf)	0.48	0.45	0.57	0.52	0.55	0.52	0.51	0.51	0.51	0.51	0.51
Depletion ($/mcf)	0.27	0.28	0.28	0.28	0.29	0.28	0.28	0.28	0.28	0.28	0.28