2000 Annual Report

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, 2000 **Commission file number 0-10697**

Dorchester Hugoton, Ltd.

(Exact name of registrant as specified in its charter)

Texas	**75-1829064**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1919 S. Shiloh Road, Suite 600-LB48, Garland, Texas 75042-8234
(Address of principal executive offices, including Zip Code)

Registrant's telephone number, including area code: **(972) 864-8610**

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

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

Depositary Receipts for Units of Limited Partnership Interest in Dorchester Hugoton, Ltd.
(Title of Class)

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. ☑

The aggregate market value of the voting securities held by non-affiliates of the registrant on **January 1, 2001** was **$144,685,613**.

As of **February 1, 2001**, there were outstanding Depositary Receipts for **10,744,380** Units of Limited Partnership Interest in Dorchester Hugoton, Ltd.

Documents Incorporated by Reference: **None**

CROSS REFERENCE SHEET

Form 10-K Item Number and Caption		Caption in Form 10-K
PART I:		
1.	Business	Business and Properties of the Partnership
2.	Properties	Business and Properties of the Partnership
3.	Legal Proceedings	Financial Information
4.	Submission of Matters to a Vote of Security Holders	None
PART II:		
5.	Market for Registrant's Common Equity and Related Stockholder Matters	Depositary Receipts and the Depositary Agreement
6.	Selected Financial Data	Selected Financial Data
7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	Management's Discussion and Analysis of Financial Condition And Results of Operations
8.	Financial Statements and Supplementary Data	Financial Information
9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	None
PART III:		
10.	Directors and Executive Officers of the Registrant	The Partnership
11.	Executive Compensation	The Partnership
12.	Security Ownership of Certain Beneficial Owners and Management	Principal Holders
13.	Certain Relationships and Related Transactions	The Partnership
PART IV:		
14.	Exhibits and Reports on Form 8-K	Financial Information

BUSINESS AND PROPERTIES OF THE PARTNERSHIP

Dorchester Hugoton, Ltd. (the ''Partnership'') has its principal place of business at 1919 S. Shiloh Road, Suite 600-LB 48, Garland, Texas 75042-8234 (telephone (972) 864-8610) with field offices in Hooker, Oklahoma and Amarillo, Texas and employed fourteen full time permanent employees (not including General Partners) as of January 1, 2001. The Partnership was formed on June 16, 1982 as a Texas limited partnership pursuant to a Certificate and Agreement of Limited Partnership (as amended, the ''Partnership Agreement''). Depositary receipts for units of limited partnership interest were originally distributed on August 20, 1982 in the form of a taxable property dividend.

The Partnership's principal operating assets consist of working interests and support facilities for properties that produce natural gas from the Hugoton gas field in Kansas and Oklahoma. The Hugoton field is considered one of the most prolific gas fields in the United States. All of the Partnership's current working interest wells (except for Kansas infill wells and Oklahoma replacement and Fort Riley wells) were drilled and have been producing since prior to 1954.

Oklahoma Properties

During 1998 the Partnership sold its working interest in one non-operated Oklahoma well and, at the same time, acquired overriding royalty interests in one Partnership owned and operated well. As a result, the Partnership's Oklahoma working interests changed from 128 natural gas wells (115.7 net wells) to 127 natural gas wells (115.2 net wells) in the Guymon-Hugoton field. Additionally, the Partnership's gross developed Oklahoma acreage changed from 80,501 acres (74,621 net acres) to 79,861 acres (74,301 net acres). The Partnership continues to operate and own interests in 117 wells in Oklahoma, of which the Partnership has a 100% working interest in 109 wells, working interests ranging from 50% to 88% in 5 wells and liquefiable hydrocarbons interests only in the remaining 3 wells. The Partnership also has working interests ranging from 25% to 50% per well in a 10 well group (previously 11) operated by an unaffiliated third party. The Partnership also has minor royalty interests in various producing natural gas wells. During December 1999 the Partnership acquired a 1.6% royalty interest in one well operated by the Partnership and in one non-Hugoton well operated by others. During December 2000, the Partnership acquired a 4.5% royalty interest in another Oklahoma Partnership operated well.

Of the Partnership's 127 gas wells, 124 deliver natural gas through a 132 mile Partnership owned and operated gas pipeline gathering system to the Partnership's Oklahoma gas compressor station. Beginning November 1, 1994, the Partnership began operation of a new 5400 horsepower gas compression and dehydration facility and delivered gas to Panhandle Eastern Pipe Line Company (''PEPL''). Numerous other transmission pipelines are also nearby. The total cost of these facilities was $6.0 million which included offices and warehouse storage for both field and compressor operations. During 1999 the Partnership installed two field rental gas compression units in Oklahoma. See ''Regulation and Prices'' for more information.

The Partnership began delivery of gas from its Oklahoma compression facilities to Williams Gas Processing — Mid Continent Region Co., a subsidiary of the Williams Companies, Inc. during December, 1996 following Federal Energy Regulatory Commission approval. Williams Field Services Company subsequently processes the gas at its plant near Baker, Oklahoma and returns the gas as directed by the Partnership to the available transmission pipelines at the plant outlet which include Williams Natural Gas Company, PEPL, and Natural Gas Pipeline Company of America. The gas returned to the Partnership for subsequent sale is of improved quality, including having the contaminant nitrogen removed.

Wells in the Guymon-Hugoton field are drilled into a 150 feet thick geological formation commonly called the Chase Group. An average Partnership well will encounter the top of the Chase Group approximately 2,700 feet below the surface. This formation typically consists of non-productive shale rock layers that separate the productive zones commonly called Herington, Krider, Winfield and the deeper Fort Riley, which is sometimes referred to as Towanda. At the time of drilling the

Partnership's wells (primarily during the late 1940's), the Fort Riley zone was considered to contain salt water rather than natural gas and was not penetrated. Based on current information, the Fort Riley zone for the most part appears to be full of water.

The Partnership believes that it is possible that some of the Partnership acreage contains gas productive Fort Riley zones without excessive water saturation. The Partnership's existing wells are mechanically not capable of being deepened. Consequently, to explore in the Fort Riley zone requires drilling a well and isolating the zone for testing. Considering the numerous unknown factors such as possible salt water and possible previous lateral gas migration in the Fort Riley, the Partnership continues to urge caution in predicting the outcome of such exploration.

Thus far the Partnership has drilled and completed three wells to test the Fort Riley zone. Each of the three wells replaced an existing gas well which was plugged and abandoned as required by Oklahoma regulations. The first of the three wells initially appeared to be favorable in both the Fort Riley zones and Winfield/Krider zones; however, subsequent testing indicated that gas leaked upward through the shale rock layer separating the zones, causing Fort Riley evaluations to be inconclusive. The first of the three wells recently produced 437 MCFD at 54 psig which is an improvement over the plugged well's previous 105 MCFD at 24 psig. The second of the three Fort Riley test wells was not as successful, producing 78 MCFD while pumping 30 bbls of water per day. This second well replaced a Winfield/Krider well that produced 175 MCFD with no water. In December 1998, this second Fort Riley well was plugged and recompleted in the Winfield/Krider zone and recently produced 148 MCFD at 17 psig. The third Fort Riley test recently produced between 51 MCFD at 17 psig while pumping 7 bbls of water per week. The third Fort Riley test replaced a Winfield/Krider well that produced 85 MCFD at 20 psig.

Kansas Properties

The Partnership currently operates and owns 100% of the working interest in 20 natural gas wells producing from the Kansas Hugoton field on 7,035 gross developed acres. The natural gas from these operated wells is currently delivered through a 26 mile gas gathering pipeline and compression facility owned by the Partnership and is sold in the field at spot market prices. Compared to 1998 and 1999, Kansas 2000 sales volumes have decreased. Such decreases are primarily a result of declining Kansas reservoir pressures experienced by the Partnership and other producers in the area. On November 5, 1997 the Partnership began operation of additional gas gathering pipelines and seven rental gas compressor units which are scattered over a ten mile area. Initial results showed a favorable increase in gas sales accompanied by an increase in condensed water accumulation in the gathering pipelines. The total capital cost was approximately $470,000. The Partnership's Kansas operating costs for such field gas compression operations were approximately $344,000 in 1998, $288,000 in 1999 and $243,000 in 2000.

During 1986, the Kansas Corporation Commission ("KCC") issued an order authorizing infill drilling on 320 acre spacing. Previously, each gas well required 640 acres. The Partnership drilled and completed on its operated properties eight producing wells through 1990 and one each in 1995, 1996 and 1997. One infill well was plugged in 1992 and another in 1993 for economic reasons.

During July 1998 the Partnership acquired in Kansas a royalty interest of approximately 3% that included two wells operated by the Partnership and two non-Hugoton wells operated by others. The Partnership also has minor overriding royalty interests in producing natural gas wells in Kansas.

Natural Gas Reserves And Other Financial Data

Information with respect to the Partnership's natural gas reserves and other financial data is presented in Note 4 to the Financial Statements included elsewhere herein.

Partnership Operations

The Partnership has operated most of its properties since July 1, 1984. Historically the cash necessary to pay the costs and expenses of operating the Partnership and its properties, including debt service, has been provided by the cash flow from the Partnership's producing properties. To the extent that Partnership operations, including any future development of its properties, require cash in excess of the Partnership's cash flow, the Partnership has secured a financing commitment from a bank. See Note 2 to the Financial Statements for a discussion regarding current bank borrowings.

Regulation And Prices

The transportation of natural gas after sale by the Partnership is subject to regulation by federal authorities, specifically by the Federal Energy Regulatory Commission (also referred to as the ''FERC''), and production of natural gas is regulated by various state agencies or authorities. The Partnership's operations are also affected by various statutory controls or obligations and, in varying degrees, by political developments and federal and state laws and regulations. Natural gas production is affected by changing federal and state tax and other laws which are specifically applicable to the oil and gas industry, by constantly changing federal and state administrative regulations as well as possible interruption or termination by government authorities due to ecological and other considerations. Allowable gas production rates have been, and are, to varying degrees, subject to conservation and environmental laws and regulations.

Both Kansas and Oklahoma regulate the amount of natural gas that can be produced by assigning to each well or proration unit a monthly allowable rate of production. Kansas and Oklahoma also specifically regulate the drilling of new or replacement oil and gas wells, the spacing of wells, the prevention of waste of natural gas resources, environmental protection and various other matters.

At present, the Oklahoma Guymon-Hugoton field is restricted by state conservation regulations to a maximum of one well for each 640 acres (subject to minor variances). Including the Partnership's 127 wells, there are about 1,350 currently producing gas wells in the Guymon-Hugoton field owned by both independent producers and major oil and gas companies. Previously, a few producers and numerous other interested parties in the area were actively seeking either regulatory or legislative changes to enable ''increased density drilling'' similar to Kansas infill drilling on 320 acre spacing. At present, several producers in the field have actively opposed such infill drilling. The difference in beliefs appears to rest in whether such infill drilling results in increased reserves. In 1989 the Oklahoma Corporation Commission (''OCC'') concluded hearings on infill drilling and determined the present density of one well per 640 acres was adequate to drain the 640 acres. Numerous studies of the Kansas infill drilling results concluded that no new reserves were developed by infill drilling. This conclusion is consistent with the Partnership's experience in Kansas.

A change in the Guymon-Hugoton field rules allowing infill drilling could result in a large number of wells being drilled that are not needed to produce the same gas that is being produced by the existing wells. The Partnership believes it is not usually economically justifiable to drill a second well on 640 acres in Oklahoma just to produce the same gas as the original well, only faster. **The outcome and cost of infill drilling is unpredictable.** In late February 1997, Oklahoma did not pass legislation that would have allowed ''infill drilling.'' Similar proposed legislation may arise in the future. On June 21, 1999 Oklahoma enacted legislation that clarifies who must receive notices of any application for Guymon-Hugoton infill drilling. Currently no such applications have been filed and such filings are expected to be controversial and require lengthy regulatory proceedings.

On October 28, 1997 the OCC, which administers oil and gas conservation in Oklahoma, conducted a hearing on a proposal to change the allowable amount of production per well in the Guymon-Hugoton field. The hearing included contradictory viewpoints that the proposal encouraged infill drilling vs. that the proposal had no effect on the infill drilling issue. On February 4, 1998 the OCC adopted rules that essentially removed production volume limits from nearly all wells in the Guymon-Hugoton field effective July 1, 1998 and specifically provided that the rule changes have no bearing on the question of infill drilling which must be decided separately. Thus far only one company on adjoining acreage has installed gas compression to try to benefit from Oklahoma's removal of production limits. The Partnership elected to install similar rental compression to stay competitive. At present, seven of the Partnership's wells are assisted by such field compressors vs. five during 1999. The two wells recently added have increased production from an average of 298 MCFD to 355 MCFD. Costs to operate the compressor units during 2000 were approximately $79,000. The increase in production has more than offset costs of compression. Further activities by others resulting from the field rule changes and related costs and/or benefits to the Partnership are unpredictable.

The pricing of all the Partnership's gas sales, both in Kansas and Oklahoma, is primarily determined by supply and demand in the marketplace. This price can fluctuate considerably. During 2000 the lowest price was $2.27/MMBTU in January and the highest was $5.91/MMBTU in December. The Partnership anticipates continued fluctuations in marketplace pricing. See Note 1 to the Financial Statements for a discussion regarding material customers and contracts.

The FERC allows regulated transmission pipelines to transfer or sell portions of their system classified or reclassified by the FERC as gas gathering pipelines to non-regulated entities or affiliates. Most of the Partnership's Oklahoma gas was not affected by any such sale or transfer and the effect on the Partnership in Kansas has been minimal since only one of the two transmission pipelines to which the Partnership delivered gas became a non-regulated gathering pipeline in 1996. Since then the Partnership's gas from the 20 Kansas wells was delivered directly to a transmission pipeline or sold to Duke Energy Field Services, Inc. at the outlet of the Partnership's compressors. On May 1, 2000 the Partnership extended year to year a previously four-year gas sales agreement with WFS Gas Resources Company (part of Williams Companies, Inc.) providing for gathering, compression, and sale of gas at market prices. This agreement covers only 3 wells (in which the Partnership has minimal interest) that are not connected to the Partnership's Oklahoma gas gathering pipeline and compression facilities. This sales agreement replaced the previously regulated gathering and compression services provided by Williams Natural Gas Company. Both Kansas and Oklahoma have adopted state regulation of gas gathering pipeline systems available for hire which excludes the Partnership's facilities. Additionally, current court decisions in both Kansas and Oklahoma sharply restrict the practice of requiring royalty owners to bear their share of gas gathering and compression costs. The Partnership has never charged royalty owners for such costs.

Competition

The energy industry in which the Partnership competes is subject to intense competition among a large number of companies, both larger and smaller than the Partnership, many of which have financial and other resources greater than the Partnership. See Note 1 to the Financial Statements for a discussion regarding material customers.

Environmental Laws And Regulations

The costs associated with the Partnership's compliance with environmental laws and regulations has not had, and is not anticipated to have, a material effect on its capital expenditures, earnings or competitive position. The Partnership's gas production contains minimal contaminants other than nitrogen, which is inert and non-toxic. The Partnership's quarterly air emission tests at its Oklahoma compression facility continue to comply with the Oklahoma Department of Environmental Quality's air quality regulations. The Kansas Department of Health and Environment ("KDHE") on July 24, 1997 issued the Partnership an air emissions operating permit for its Kansas compression facility. Previously such a permit was not required. At present, no permits are necessary for the seven rental field compressors installed in Kansas during 1997 or the two rental field compressors installed in Oklahoma during 1999. In addition, one Kansas well underwent KDHE regulated non-hazardous soil removal and disposal to remedy minor mercury contamination during 1996 at minimal cost. No other Kansas well site required remedial attention.

DEPOSITARY RECEIPTS AND THE DEPOSITARY AGREEMENT

Immediately subsequent to its formation, all of the Partnership's units of limited partnership interest ("Units") were deposited with an authorized depositary ("Depositary"), to be held in accordance with the Depositary Agreement. Effective September 8, 1998 the Depositary became BankBoston, N.A., c/o Boston EquiServe, L.P., P.O. Box 8040, Boston, MA 02266. The Depositary maintains an account with respect to the Units deposited for which it has issued Depositary Receipts. Holders of Depositary Receipts (also referred to as "Unitholders") may transfer, combine or subdivide them at any office of the Depositary designated for such purpose. Unitholders may also surrender them to the Depositary and, upon submission of such documents as the General Partners may require, reclaim deposited Units. However, the Units will not be readily transferable and any redeposit of Units against newly issued Depositary Receipts will require 60 days advance written notice and is subject to certain other conditions.

On May 7, 1996 the Partnership announced a program to purchase from time to time up to 500,000 of the Partnership's Units. Such purchases would have been made on the open market, in private transactions, or otherwise. Purchases from the General Partners were excluded from the repurchase program. All Units repurchased under the program would be retired resulting in a decrease in both Units issued and Units outstanding. No Units would have been held as "Treasury Units." There was no assurance or obligation that the repurchase program would result in any purchase of Units. The Partnership believed the repurchase program was a way to enhance the value to our long-term investors by increasing a Unitholder's equity ownership in natural gas producing properties rather than attempting alternatives such as acquisition or exploration programs. On October 26, 1999 the Partnership terminated the authorization to repurchase and retire Units. No Units were repurchased pursuant to such authorization.

The Depositary Receipts have been traded on the Nasdaq Stock Market under the symbol "DHULZ" since August 26, 1982. The quoted market prices and reported trading volumes for 2000 and 1999 were as follows:

	2000			1999		
	Low	High	Volume	Low	High	Volume
First Quarter	8 7/8	10 1/16	687,000	9 3/8	10 1/2	867,000
Second Quarter	9 15/16	14 1/8	1,055,000	9	11 1/2	388,000
Third Quarter	13 3/8	15 5/8	966,000	10 1/8	13 1/4	481,000
Fourth Quarter	13	16 1/4	1,251,000	9	13 1/4	476,000

As of January 1, 2001, there were approximately 4,100 Unitholders.

In accordance with governance rules for limited partnerships traded on the Nasdaq Stock Market, the Partnership established in 1995 an Advisory Committee consisting of two independent advisors to function as the Partnership's Audit Committee and to review and approve any transactions between the Partnership and its General Partners, including any compensation and benefits paid to the General Partners by the Partnership. The Partnership Agreement was amended accordingly.

During 2000 the Partnership, with Advisory Committee approval, adopted an Audit Committee charter which requires an annual review that complies with the Nasdaq's Marketplace Rules. The Advisors meet all current requirements to be independent directors, including the requirement that at least one director have the necessary financial experience and background. The Advisors, acting as the Audit Committee, reviewed and discussed with the Partnership's independent outside auditors (the "Auditors") and management the audited financial statements and discussed with the Auditors the matters required to be discussed by the Statement on Auditing Standards No. 61. The Audit Committee also had private discussions with the Auditors and reviewed and discussed disclosures from the Auditors concerning their independence. The Audit Committee recommended that the audited statements appearing herewith be included in this Partnership Annual Report on Form 10-K.

The Units and the Depositary Receipts are fully paid and non-assessable. Each record holder of a Depositary Receipt evidencing the ownership of one or more Units will, for purposes of the Texas Revised Limited Partnership Act ("TRLPA"), be an assignee with respect to the interests in the Partnership represented by such Units. Each such assignee may become a Substituted Limited Partner upon (i) the execution and delivery of a request and agreement to become a Substituted Limited Partner, which includes a power of attorney to the General Partners, (ii) the approval of the General Partners to such admission as a Substituted Limited Partner and (iii) the filing of an amended Certificate of Limited Partnership evidencing the admission of such person as a Substituted Limited Partner. If such action is not taken, Unitholders will remain assignees of the interests of the Partnership represented by the Units. Under certain circumstances, a Unitholder may not become a Substituted Limited Partner if such holder is not an Eligible Citizen. Each Unitholder (whether an assignee or Limited Partner) as of the last day of each month is allocated a pro rata share of the Partnership's profits and losses for the month then ended, regardless of whether such holder receives any cash distributions from the Partnership. Each Unitholder of record (whether an assignee or Limited Partner) as of the applicable record date is entitled to receive an allocable share of any cash distributions made by the Partnership. The timing and amount of such distributions is determined by the General Partners. In addition, the Partnership's Loan Agreement with Bank One, Texas, NA requires the Partnership capital to remain above certain specified amounts. The Partnership Agreement provides that prior to the dissolution of the Partnership, the General Partners shall determine the amount of cash available for distribution, if any, at least as of the end of each calendar quarter.

Effective with the third quarter 1995 distribution, the Partnership's transfer agents have paid all distributions as declared. Distributions per Unit, including special distributions, have been as follows:

	Calendar Year										
Quarter	1982	1983	1984	1985/86	1987	1988	1989/90/91	1992	1993	1994/95/96	1997/98/99	2000
First	N/A	$.02	$.01	$.01	$.02	$.03	$.05	$.05	$.12	$.17	$.18	$.28
Second	N/A	.01	.01	.01	.02	.04	.05	.05	.15	.17	.18	.18
Third	$ .01	.01	.01	.01	.03	.04	.05	.05	.17	.17	.18	.22
Fourth	.02	.01	.01	.02	.03	.04	.05	.08	.17	.17	.18	.22
Total	$ .03	$.05	$.04	$.05	$.10	$.15	$.20	$.23	$.61	$.68	$.72	$.90

After dissolution of the Partnership, distributions to each Unitholder of record (whether an assignee or Limited Partner) will be made in accordance with the Partnership Agreement.

Hugoton Nominee, Inc., a Texas nominee corporation ("Nominee"), was formed in August 1982 on behalf of the Partnership and has agreed to act as the Limited Partner of record for those Unitholders of record who do not become Substituted Limited Partners. If Nominee receives notice of any action requiring the vote of Limited Partners, it will provide or cause to be provided such notice to the Unitholders of record representing Units for which Nominee is acting as the Limited Partner of record and inform those holders of their rights to become Substituted Limited Partners. The Partnership is required to reimburse Nominee for all expenses incurred in such capacity ($507 for 2000 and $484 for 1999) and shall indemnify it against certain liabilities incurred by Nominee in such capacity. Nominee may at any time resign or be removed by the Partnership, and a successor appointed.

The following summary is subject to the detailed provisions of the Depositary Agreement and is qualified by reference to the Depositary Agreement, copies of which are available at the Partnership's office and the Depositary.

The Depositary may at any time resign or be removed by the Partnership, and a qualified successor appointed. Any corporation into or with which the Depositary may be merged or consolidated shall be the successor of the Depositary without the execution or filing of any document or any further act.

Any provision of the Depositary Agreement, including the form of Depositary Receipt, may at any time and from time to time be amended by agreement between the Partnership and the Depositary in any respect deemed necessary or desirable by them that does not adversely affect any substantial right of the Unitholders of record. The Unitholders of record representing twenty-five percent (25%) or more of the deposited Units may at any time propose an amendment or amendments to the Depositary Agreement. Any amendment of the Depositary Agreement that imposes any fee, tax, or charge (other than fees and charges provided for in the Depositary Agreement) upon, or otherwise adversely affects any substantial rights of Unitholders of record shall not be effective until the expiration of thirty (30) days after notice of the amendment has been given to the Unitholders of record or, if the amendment is presented for a vote of the Unitholders of record, until it has been approved by the affirmative vote of the Unitholders of record representing fifty percent (50%) or more of the deposited Units. For the purpose of considering any amendment of the Depositary Agreement that adversely affects any substantial right of the Unitholders of record or any amendment proposed by Unitholders of record but not adopted by the Depositary and the Partnership, the Partnership shall call a meeting of Unitholders of record to be held at a place in Dallas, Texas designated by the Partnership. The call shall set forth the time, place, and purpose of the meeting, and notice thereof shall be mailed at least twenty (20) days before the meeting to each record holder at the close of business on the record date selected by the Partnership for the purpose of the meeting. Any record holder may waive such notice. At the meeting each record holder shall have one vote for each deposited Unit evidenced by each Depositary Receipt registered in his name and may cast such vote in person or by proxy. At the meeting the presence in person or by proxy of Unitholders of record evidencing at least fifty percent (50%) of the deposited Units shall be necessary to constitute a quorum. If a proposed amendment is approved by the Unitholders of record representing fifty percent (50%) or more of the deposited Units and if, in the case of an amendment that alters the duties or liabilities of the Depositary, the Partnership or any General Partner thereof, it is approved in writing by whichever of them is or are affected, the amendment shall be declared adopted, and upon filing with the Depositary of a certificate of the proceedings of the meeting, verified by the chairman and the secretary thereof, together with any such approval, the amendment shall thereupon become effective. In lieu of adoption at a meeting, an amendment of the Depositary Agreement may be approved if Unitholders of record as of a record date selected by the Partnership representing fifty percent (50%) or more of the deposited Units consent thereto in writing filed with the Depositary. No amendment shall impair the right of the Unitholders of record to surrender the Depositary Receipt and withdraw any or all of the deposited Units evidenced thereby. Unitholders of record will not be entitled to notice as Limited Partners or the right to vote as Limited Partners under the Depositary Agreement unless they are Substituted Limited Partners (see notice requirements of Nominee above).

The Depositary shall terminate the Depositary Agreement whenever directed to do so by the Partnership by mailing notice of termination to the Unitholders of record then outstanding at least thirty (30) days before the date fixed for the termination in such notice.

In addition to acting as depositary for the Units, the Depositary will act as registrar and transfer agent for the Depositary Receipts. In addition to receiving a monthly fee from the Partnership for serving in such capacities, the Depositary will charge fees for Depositary Receipt transfers comparable to those customary for stock transfer fees. All Depositary fees for transfer of Depositary Receipts and withdrawal of Units will be borne by the Partnership and not the Unitholders (except for fees customarily paid by stockholders for surety bond premiums to replace lost or stolen certificates, special charges for services requested by Unitholders and other similar fees or charges which will be borne by the affected Unitholders). The Partnership will indemnify the Depositary against certain liabilities incurred by the Depositary in connection with its activities as depositary, transfer agent and registrar, including liabilities arising under the Securities Act of 1933.

The Depositary may terminate the Depositary Agreement if, after the Depositary has delivered to the Partnership a written notice of its election to resign, sixty (60) days have elapsed and a successor Depositary has not accepted its appointment. The Depositary shall mail notice of termination to the

Unitholders of record. Termination shall be effective on the date fixed in the notice, which shall be at least thirty (30) days after it is mailed.

PRINCIPAL HOLDERS

The following table sets forth certain information regarding the beneficial ownership of Units by the General Partners, their officers, and the Partnership's officer effective as of January 1, 2000 and other persons, excluding depositaries, of record on January 1, 2000 who held 5% or more of the Units.

	Number of Units Beneficially Owned	Percent of Class (1) (3)
P. A. Peak, Inc., General Partner	—	—
Preston A. Peak, President of P.A. Peak, Inc	1,577,412 (2)	14.68%
James E. Raley, Inc., General Partner	—	—
James E. Raley, President of James E. Raley, Inc	14,706	.14%

(1) Based on 10,744,380 Units.

(2) Includes 1,576,412 Units owned by various entities for the benefit of Mr. Peak and his family, and 1,000 Units owned by Hugoton Nominee, Inc. of which he is the President and sole Director.

(3) The Units owned by the Advisory Committee members and the non-general partner officer of the Partnership is less than 1% of the total Units outstanding at December 31, 2000.

THE PARTNERSHIP

The following summary contains certain provisions of the Partnership Agreement. The Partnership was formed pursuant to the TRLPA to own, hold, explore, develop and operate the properties contributed to it at its formation and any other properties acquired pursuant to the Partnership Agreement.

The Partnership Agreement was amended August 9, 1995 to provide for an Advisory Committee and to make certain other amendments which were necessary to conform to, or to provide desired flexibility permitted by, changes in Texas partnership law and federal tax law. The amendments were filed with the June 30, 1995 United States Securities and Exchange Commission Form 10-Q.

The statements herein relating to the Partnership Agreement are summaries and do not purport to be complete. The summaries make use of terms defined in the Partnership Agreement and are qualified in their entirety by reference to the Partnership Agreement, a copy of which is available at the Partnership's office.

Management Of The Partnership

The General Partners, who have purchased an aggregate 1% net profits interest in the Partnership, are P. A. Peak, Inc. whose sole shareholder is Preston A. Peak, age 78, Investor, and James E. Raley, Inc., whose sole shareholder is James E. Raley, age 61, Engineer. Kathleen A. Rawlings, age 43, is the Partnership's Principal Accounting Officer and Administrative Services Manager. She has been a full-time employee of the Partnership since 1983. Mr. Peak is a former member of the Board of Directors of Kaneb Services, Inc. as well as one of its subsidiaries. Mr. Raley is an independent consulting engineer.

The Partnership established an Advisory Committee consisting of two independent advisors in August, 1995 to function as the Partnership's Audit Committee and to review and approve any transactions between the Partnership and its General Partners, including any compensation and benefits paid to the General Partners by the Partnership. Mr. Rawles Fulgham of Dallas, Texas and Mr. W. Randall Blank of Houston, Texas presently serve on the Advisory Committee. Mr. Fulgham previously served as Chairman and Chief Executive Officer of Global Industrial Technologies, Inc. and is currently a director of NCH Corporation. Mr. Blank is currently a consultant active in the natural gas industry. Previously, he was the Executive Vice President of Rockland Pipeline Company in Houston, Texas. He also serves on the Board of Directors of Panther Natural Gas Company.

The General Partners have complete and exclusive discretion in the management and control of the business of the Partnership and all of its assets, including authority to purchase or otherwise acquire any lease or other interest in oil or gas property located within the geographical areas covered by the properties conveyed to the Partnership and such other geographical areas within the Hugoton Embayment as the General Partners may designate from time to time, to borrow monies for the business of the Partnership, and to mortgage or pledge all or any part of the Partnership's property as security, to surrender, release or abandon any Partnership property, with or without consideration therefor, and generally to execute and deliver such other documents and perform such other acts as the General Partners in their sole discretion may determine to be necessary or appropriate to carry out the business and affairs of the Partnership.

Under the Partnership Agreement, each General Partner is entitled to receive reasonable compensation for services rendered in operating and managing the Partnership. The agreement, as amended effective January 1, 1998, provides for a management fee to be divided among the General Partners in an annual aggregate amount of $350,000 (previously $250,000) plus 1% of the annual gross income of the Partnership from the Partnership properties. These amounts, on an accrual basis, are included in the heading All Other Compensation within the following table (no salaries, bonuses or other annual compensation was paid or accrued):

SUMMARY COMPENSATION TABLE	All Other Compensation		
Year	Preston A. Peak or P.A. Peak, Inc. General Partner	James E. Raley or James E. Raley, Inc. General Partner	Total for Year
1998	$ 88,830	$407,055(a)	$495,885
1999	$ 88,509	$407,484(a)	$495,993
2000	$137,905	$459,283(a)	$597,188

(a) Includes the amount of taxable medical insurance premiums and payments of $5,225, $5,975, and $8,378 for James E. Raley in 1998, 1999, and 2000, respectively.

Amounts expended by the Partnership for expenses (including certain private club dues and office and other expenses) reimbursed or expended on behalf of employees and the General Partners are believed to constitute ordinary and incidental business expenses and are paid by the Partnership to facilitate the conduct of Partnership business by such employees and General Partners. The Partnership has concluded that the aggregate amount, if any, of personal benefit is neither significant nor unusual nor does it result in any material additional expense (less than $50,000) to the Partnership. During 2000, the General Partners were reimbursed a total of $31,850 for all expenses incurred by them on behalf of the Partnership, including their general and administrative expenses. No employees or officers of the corporate General Partners participate in the Partnership's simplified employee pension plan. Fees and expenses paid to members of the Advisory Committee amount to less than $30,000 annually.

Upon the resignation or other Withdrawal of a General Partner, the remaining General Partners must select a Successor General Partner who is not an affiliate of any General Partner and must notify the Unitholders and Limited Partners (collectively referred to as the "Unitholders") of such selection. Such Successor General Partner shall be accepted unless Unitholders holding more than 25% of the Units call a meeting and a majority in interest of the Unitholders entitled to vote at such meeting disapprove the selection. So long as there is more than one General Partner, the approval of a majority of the General Partners is required to bind the Partnership, except as the General Partners may from time to time delegate responsibility among themselves or to others.

The General Partners shall not permit the Partnership to do business in any jurisdiction or political subdivision in which the General Partners and the Partnership have not previously taken such steps as may be necessary to assure for the Limited Partners substantially the same limited liability as is provided for limited partners in limited partnerships formed under the TRLPA.

Transactions With Affiliates

The Partnership Agreement specifically provides that an Affiliate of the Partnership may enter into contracts with the Partnership as operator, seller or purchaser of properties or services, or in other capacities, so long as the transactions are fair and reasonable to the Partnership and the terms of any contract or conveyance are no less favorable to the Partnership than those which could be obtained from unrelated persons. However, the Partnership shall not sell any part of an oil and gas mineral lease to an Affiliate without the prior consent of a majority in interest of the Unitholders. All transactions between the Partnership and its General Partners and/or their Affiliates will be reviewed and approved by the Advisory Committee.

Immunities And Indemnities

The Partnership Agreement also provides that no General Partner, nor any shareholder, director, officer, employee or agent of a General Partner, shall be liable to the Partnership or to the Partners for losses sustained or liabilities incurred as a result of any act or omission which such General Partner in good faith reasonably believed to be in, or not opposed to, the best interests of the Partnership, unless such act or omission constituted gross negligence, willful or wanton misconduct or breach of such General Partner's fiduciary obligations to the Unitholders. A General Partner may rely upon, and shall have no liability to the other Partners or to the Partnership if he relied upon, the opinion of the Partnership's independent public accountants with respect to any matter relating to computations and determinations which affect allocations or distributions. Each General Partner is indemnified by the Partnership as follows:

(a) In any threatened, pending or completed action, suit or proceeding to which a General Partner was or is a party by reason of the fact that it is or was a General Partner of the Partnership (other than an action by or in the right of the Partnership), involving an alleged cause of action, arising out of the manner in which such General Partner conducted the Partnership's business if, in the transaction giving rise to such action, suit or proceeding, such General Partner acted in good faith and in a manner such General Partner reasonably believed to be in, or not opposed to, the best interests of the Partnership and such General Partner's conduct in such transaction did not constitute gross negligence, willful or wanton misconduct or willful breach of such General Partner's fiduciary obligations to the Unitholders.

(b) In any threatened, pending or completed action, suit or proceeding by or in the right of the Partnership, to which a General Partner was or is a party, or is threatened to be made a party, by reason of the fact that it is or was a General Partner of the Partnership, involving an alleged cause of action arising out of the manner in which such General Partner managed the internal affairs of the Partnership as prescribed by the Agreement or by the TRLPA, or both (but excluding the activities covered in (a) above), if, in the transaction giving rise to such action, suit or proceeding, such General Partner acted in good faith and in a manner such General Partner reasonably believed to be in, or not opposed to, the best interests of the Partnership, except that no indemnification shall be made in respect of any claim, issue or matters as to which such General Partner shall have been adjudged to be liable for gross negligence, willful or wanton misconduct or breach of such General Partner's fiduciary obligations to the Unitholders, unless and only to the extent that the court in which such action, suit or proceeding was brought shall determine upon application that, despite the adjudication of liability but in view of all circumstances of the case, such General Partner is fairly and reasonably entitled to indemnity for such expenses which such court shall deem proper.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to a General Partner pursuant to the foregoing provisions, the Partnership has been informed that in the opinion of the United States Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is therefore unenforceable.

Actions By Unitholders

A majority in interest of the Unitholders shall have the right to waive any restriction on the General Partners contained in the Partnership Agreement. The Applicable Percentage Interest of the Unitholders (since June 16, 1988, defined as Unitholders who own 80% of all Units) shall have the right to dissolve the Partnership, to amend the Partnership Agreement, to approve or reject the sale of all or substantially all of the Partnership Property in the event that the General Partners do not approve or recommend such sale, or to remove one or all of the General Partners and elect a successor General Partner to operate and carry on the business of the Partnership, subject in each case to receipt of an opinion of counsel for the Unitholders or a ruling from the Internal Revenue Service that the taking of such action will not affect the federal income tax status of the Partnership, and subject further in the case of the removal and replacement of a General Partner, to the following:

(a) The partnership interest of each removed General Partner must be terminated by agreement between such terminating Partner and the successor General Partner or, in the absence of an agreement, in accordance with the following: The assets of the Partnership shall be valued, and gain or loss allocated, as if all assets were sold for their fair market value as determined by independent consulting engineers. Then, within 30 days after such valuation is completed, the successor General Partner shall pay for the Partnership interest of each removed General Partner cash equal to the capital account balance of such Partner, after adjustment for the valuation and allocation provided above, plus interest at a rate equal to the lower of (i) the prime rate of Bank One, Texas, NA or (ii) the highest rate permitted by law, for a period from the valuation date until the payment date. The Partnership interest of each terminating Partner, including income and deductions attributable thereto realized after the valuation date, shall be owned by the successor General Partner.

(b) The successor General Partner must make arrangements, satisfactory to the removed General Partner, to release the removed General Partner from personal liability with respect to all Partnership liabilities, if any, or to provide the removed General Partner with indemnity satisfactory to it against all liabilities of the Partnership with respect to which such release is not obtained.

Meetings of the Unitholders may be called by any General Partner and shall be called by the General Partners within 15 days following the written request of Unitholders holding more than 50% of the Units on not less than 30 days nor more than 60 days notice and at a reasonable time and place. There were no meetings of the Unitholders held during 2000. Any action which may be taken at a meeting of the Unitholders may be taken without a meeting if a consent in writing, setting forth the action so taken, shall be signed by Unitholders owning not less than the minimum percentage of Units that would be necessary to authorize or take such action at a meeting at which all Unitholders were present and voted. For purposes of obtaining a written consent, a General Partner may require response by a specified date not later than 30 days after the date any proposal is submitted to the Unitholders. Any Unitholder failing to notify the Partnership of his support for or opposition to the proposal within the specified time shall be conclusively deemed to have opposed the proposal.

No Unitholder shall have any right, power or authority to take part in the management or control of the business of, or to transact any business for, the Partnership. All management responsibility is vested in the General Partners. Each Unitholder irrevocably constitutes and appoints the General Partners, and each of them, his true and lawful attorney-in-fact and agent, to execute, acknowledge, verify, swear to, deliver, record and file, in the Unitholder's place and stead, all instruments, documents, and certificates which may be required, from time to time, by the laws of the United States of America, the State of Texas, and any other state or country in which the Partnership conducts business to effectuate, implement and continue the valid existence of the Partnership. This power of attorney is coupled with an interest, and shall be irrevocable, shall survive the death, dissolution, bankruptcy, incompetency or legal disability, of a Unitholder and shall extend to each Unitholder's heirs, successors and assigns and may be exercised for all Unitholders (or any of them) by listing all (or any) of the Unitholders required to execute any instrument.

No Limited Partner shall be required to make any additional contributions to the Partnership. If additional funds are required, the General Partners will attempt to obtain non-recourse loans but shall not be obligated to seek recourse loans if non-recourse loans are not available. If any General Partner loans any funds to the Partnership, the amount thereof shall be treated as a personal debt of the Partnership, and shall bear interest at the prime rate set by Bank One, Texas, NA.

Accounting And Allocations

For federal income tax purposes, income, gain, loss, deductions and federal tax credits shall be allocated on a monthly basis to the partners in accordance with their profit sharing percentages. The General Partners have the right to make or decline to make all elections required or permitted to be made for federal income tax purposes, including the Section 754 election, and such elections, other than the Section 754 election, shall also be controlling for book purposes. The classification, realization and recognition of income, deductions and other items shall be consistent with their treatment for federal income tax purposes applicable to a partnership electing the method of accounting which the General Partners elect and the elections provided for above, other than the Section 754 election. The Partnership Agreement requires that within two and one-half months after the end of each fiscal year, the General Partners must furnish to each Unitholder a statement containing necessary information concerning the Partnership's operations for the preceding fiscal year.

Transfers

The Partnership interest of a General Partner may be transferred, in whole or in part, only with the consent of the other General Partners, except where such transfer is by reason of merger of a transferor corporate General Partner into another corporation, or other transaction constituting a reorganization under Section 368 of the Internal Revenue Code. As discussed above, the Partnership Agreement contains provisions for valuing the Partnership interest of a General Partner. A Unitholder may transfer all or part of his Units to any person or persons; provided, however, that such transfer shall not confer upon the transferee any right to become a Substituted Limited Partner. A transferee of all or a part of such Units held prior thereto by a Unitholder may be admitted to the Partnership as a Substituted Limited Partner only if the transferee had requested and received the permission of the General Partners, which permission may be withheld in the sole discretion of the General Partners. Unless and until a transferee becomes a Substituted Limited Partner, the transferee's status and rights shall be limited to the rights of a transferee of limited partnership interests under the TRLPA. To the extent required by applicable law, if a transferee is not an Eligible Citizen, a Depositary Receipt evidencing the transferred Units will be issued and delivered to him, but he shall not be entitled to admission as a Substituted Limited Partner and shall remain a non-citizen assignee until he transfers the Units or he becomes an Eligible Citizen and elects to become a Substituted Limited Partner. An Eligible Citizen means a citizen or national of the United States; an alien lawfully admitted for permanent residence in the United States; a private, public or municipal corporation organized under the laws of the United States or of any State or of the District of Columbia, or a territory thereof; or an association of such citizens, nationals, resident aliens, or private, public or municipal corporations, States or political subdivisions of States. If at any time the Partnership or a General Partner is named a party in any judicial or administrative proceeding that seeks the cancellation or forfeiture or any property in which the Partnership has an interest because of the nationality (or any other status that subjects the Partnership to the risk of losing its eligibility to acquire or hold oil and gas leasehold interests in federal lands) of any one or more Unitholders the General Partners may redeem the partnership interest of such Unitholder.

Dissolution And Liquidation

The Partnership shall be dissolved upon the first to occur of the following events:

(a) The failure of the Partnership to own any oil and gas properties.

(b) The Withdrawal of a General Partner, which is defined as the death, dissolution, resignation, insanity or other incapacity of a General Partner, termination of a marital relationship in which all or a part of the record or beneficial ownership of the General Partner is transferred, certain bankruptcy acts of a General Partner or a purported transfer by a General Partner of his management rights in the Partnership (subject to reconstitution as referred to below).

(c) The agreement of the Applicable Percentage Interest of the Unitholders.

(d) The agreement of all General Partners.

(e) December 31, 2050.

The dissolution shall be effective on the day the event occurs giving rise to the dissolution, but the Partnership shall not terminate until all its affairs have been wound up and its assets distributed. If the Partnership dissolves because of the Withdrawal of a General Partner, the Partnership shall not liquidate, but shall be reconstituted and shall continue as it was before.

In liquidation, the assets of the Partnership shall be applied in the following order or priority:

(a) First, there shall be paid all liabilities of the Partnership to creditors other than Partners and Unitholders (collectively referred to as the "Partners"). If any liability is contingent, or uncertain in amount, a reserve equal to the maximum amount to which the Partnership could be reasonably held liable will be established. Upon the satisfaction or other discharge of such contingency, the amount of the reserve not required, if any, will be distributed in accordance with the balance of this provision.

(b) Second, the debts, if any, of the Partnership to the Partners shall be paid.

(c) Third, to the Partners in an amount equal to their then existing Capital Accounts. If any General Partner's Capital Account is less than zero, then each such Partner shall contribute cash to the Partnership equal to such deficit.

(d) Fourth, to the Partners in accordance with their Profit Sharing Percentages.

Each Partner agrees with every other Partner that (i) any Partner and any person affiliated with a Partner may engage in or possess any interest in another business venture or ventures; (ii) neither the Partnership nor the other Partners shall have any right in said independent venture or to the income or profits derived therefrom; and (iii) any General Partner may organize and be a General Partner in other limited partnerships organized for the exploration for oil, gas and other minerals or for any other purpose.

Amendments

Amendments to the Partnership Agreement may be proposed by any General Partner, or by Unitholders owning not less than 50% of the Units and must be approved by the Applicable Percentage Interest of the Limited Partners. However, no amendment shall be made which would cause the Partnership to be classified as a corporation for purposes of the Internal Revenue Code. Without notice to the Unitholders, the General Partners may make amendments to the Partnership Agreement which do not adversely affect the rights of the Unitholders in any material respect.

Inheritance Taxes

Under certain circumstances, Texas inheritance tax and other laws regarding devolution, probate and administration may be applicable to property in Texas, including intangible personal property, of both resident and nonresident decedents. Insofar as the Depositary Receipts may represent or constitute an interest in property in Kansas and Oklahoma, they may be subject to devolution, probate and administrative laws, and inheritance, gift and similar taxes, under the laws of such states.

Income Tax Treatment

Dorchester Gas Corporation received the opinion of counsel that the Partnership would be classified as a partnership and that the Unitholders would be treated as limited partners for federal income tax purposes. **As a natural resources partnership, the Partnership was not affected by existing tax provisions that caused certain publicly traded partnerships to be taxed as corporations in 1998.** The Partnership itself, to the extent that it is treated for federal income tax purposes as a partnership, is not subject to any federal income taxation, but it is required to file annual partnership returns of income. Each Unitholder will be required to take into account in computing his federal income tax liability his distributive share (determined in accordance with the allocation of profits and losses set forth in the Partnership Agreement) of all items of Partnership income, gain, loss, deduction or credit for any taxable year of the Partnership ending within or with his taxable year without regard to whether such Unitholder has received or will receive any cash distributions from the Partnership. The profits and losses of the Partnership are allocated 1% to the General Partners and 99% to the Limited Partners. The IRS may assess a deficiency attributable to Partnership items within three years after the Partnership return is filed. The applicable period of limitation with respect to Partnership items may be extended for all Unitholders by the General Partners. No period of limitation extensions have been granted at this time.

A Unitholder's distributive share of the taxable income or loss of the Partnership generally will be required to be included in determining his reportable income for state or local tax purposes in the jurisdiction in which he is a domicile or resident. In addition, the Partnership will conduct operations in some states, including Kansas and Oklahoma, which impose a tax on a Unitholder's share of the income derived from the activities or properties of the Partnership in that state whether or not the Unitholder is a resident or domicile of such state. Accordingly, a Unitholder may be subject to taxes in a state in which the Partnership has operations or properties in addition to the state in which the Unitholder has his residence or domicile. The Partnership initiated an agreement with the Kansas Department of Revenue removing the reporting burden for Unitholders who are nonresidents of Kansas and satisfying any tax liability that might exist with respect to their allocable share of Partnership income attributable to Kansas for 1982 through 2000.

In view of the complexities of the tax considerations involved in the ownership of Depositary Receipts, the holders of such are urged to consult tax or legal advisors to determine how and to what extent such holders will be taxed for federal and state income tax purposes and to determine all other legal consequences to such holders of that status (See Note 1 to the Financial Statements).

DORCHESTER HUGOTON, LTD.
(A Texas Limited Partnership)

SELECTED FINANCIAL DATA
For the Years Ended December 31, 2000, 1999, 1998, 1997, and 1996
(Dollars in Thousands)

	2000	1999	1998	1997	1996
Net operating revenues	$25,182	$15,302	$15,366	$19,159	$17,055
Net earnings	$17,962	$ 9,046	$ 9,010	$12,665	$ 7,830
Net earnings per Unit	$ 1.66	$ 0.83	$ 0.83	$ 1.17	$ 0.72
Cash distributions per Unit	$ 0.90	$ 0.72	$ 0.72	$ 0.72	$ 0.68
Total assets at December 31	$38,709	$28,165	$26,444	$25,215	$22,683
Notes payable — long term	$ 100	$ 100	$ 100	$ 122	$ 3,144
Partnership capital at December 31	$32,930	$24,338	$22,641	$20,841	$15,389

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The Partnership's year to year changes in net earnings and cash flows from operating activities are principally determined by changes in natural gas sales volumes and gas prices. As shown in the following table, overall gas sales volumes were down 7% from 1998 to 1999 and down 3.5% from 1999 to 2000. Natural gas market prices were up 7% from 1998 to 1999 and up 72% from 1999 to 2000. Net earnings were $9,010,000 in 1998, $9,046,000 in 1999, and $17,962,000 in 2000. Operating cash flows were $10,501,000 in 1998, $11,045,000 in 1999, and $18,526,000 in 2000. On May 15, 2001 the Partnership will pay an Oklahoma production payment of approximately $1,701,000 for the year ended February 28, 2001, of which approximately $1,176,000 was accrued through December 31, 2000. On March 15, 2000 a special distribution of $0.10 per Unit was paid to Unitholders of record on February 29, 2000. On April 14, 2000 and July 14, 2000 the Partnership paid distributions of $0.18 per Unit for the first two calendar quarters of 2000. On October 13, 2000 and January 12, 2001 the Partnership paid an increased quarterly distribution of $0.22 per Unit for the third and fourth calendar quarters of 2000. The total of the five distributions was approximately $9,768,000.

In order to supplement its cash flows from operating activities and finance significant capital projects, the Partnership entered into a $15 million long-term unsecured revolving credit facility (the "Credit Agreement") with Bank One, Texas, NA in 1994. See Note 2 to the Partnership's Financial Statements for additional information on the Credit Agreement. The Partnership does not believe that changes in interest rates will have a material effect on its financial condition or operating results. Cash flows from operating activities remain sufficient to meet the Partnership's anticipated costs and expenses and debt service requirements. The Partnership has no current outstanding material commitments for capital expenditures. Year end cash and cash equivalents totaled $7,017,000 for 1999 and $15,767,000 for 2000. The Partnership's ownership of Exxon (now Exxon Mobil Corporation) common stock increased from 54,000 to 64,000 shares during 1998. An accrual of $500,000 was recorded to other expense during June 2000 and reversed during October 2000. This accrual included $100 per Partnership K-1 or $446,100, excluding interest, as a penalty for a clerical error in requesting automatic extensions of time to file tax returns. All tax year 1999 federal and state tax returns had been filed and all Unitholders timely received their K-1's. The Partnership contested the federal penalty which was fully eliminated.

The Partnership's 5,400 horsepower gas compression and dehydration facility in Oklahoma has continued to operate satisfactorily since its start-up in November 1994. Major maintenance was performed in 1998 and is scheduled again during 2001. The Partnership anticipates normal gradual increases in repairs. Electronic measurement was installed on the Oklahoma gas gathering pipelines during 1996 and in Kansas during 2000. Field consumption of natural gas at the compression and dehydration facilities is estimated to be approximately 4.5% of the Oklahoma inlet gas volume and 10.3% in Kansas as a result of field compression. The Partnership anticipates gradual increases in Oklahoma field operating costs and expenses as repairs to its 50-year-old pipelines and gas wells become more frequent and as pressures decline. The Partnership does not anticipate significant replacement of these items at this time. During 1999, the Partnership concluded testing and reinstallation of anodes (corrosion protection devices) on the Oklahoma gas pipeline gathering system.

The routine workover of wells in Oklahoma includes fracture treating (the creation of cracks in the formation to assist gas flow toward the well bore from the producing zones). Currently, the Partnership has fracture treated 30 wells in Oklahoma which includes 13 wells during 2000. Such fracture treatments during 2000 have cost from $25,000 to $35,000 per well. Of the 13 wells, 11 increased in gas production volume and 13 increased in gas pressure. The combination of an increase in pressure and volume resulted in an overall increase of 34% in gas reserves for the 13 wells. Based on the continued favorable performance of the 17 wells fracture treated during 1997-1999, gas reserves have increased overall 65% as a result of fracture treating the 17 wells compared to 49% reported last year. The overall increase for the 30 wells is 53%. **The results of fracture treating can vary widely from well to well and may not be successful.** Average Oklahoma per well volume increases for the 13 wells were 57% (132 to 207 MCF per day). The Partnership anticipates continuing additional fracture treating during 2001.

The Partnership's portion of gas sales volumes (in MMCF) not reduced for Oklahoma production payment, and weighted average BTU adjusted sales prices per MCF were as follows:

	Year Ended December 31		
	2000	1999	1998
Sales Volumes:			
Oklahoma	5,576	5,580	5,739
Kansas	1,082	1,320	1,696
Total	6,658	6,900	7,435
Weighted Average Sales Prices:			
Oklahoma	$ 3.95	$ 2.28	$ 2.11
Kansas	3.99	2.36	2.22
Overall weighted average	3.96	2.30	2.14

Oklahoma 2000 gas sales volumes were essentially unchanged from 1999 and within 3% of the 1998 volumes largely because of volume increases from fracture treating offsetting natural declines. The Partnership drilled and completed one Fort Riley test well in 1997 and two in 1998. The second well has been plugged and recompleted in an upper zone — see the Business and Properties of the Partnership — Oklahoma Properties section of this annual report. The Partnership will continue to evaluate the Fort Riley zone including monitoring the activities of other operator's Fort Riley completions. Further Fort Riley drilling will await the results of this evaluation. As discussed in Business and Properties of the Partnership — Regulations and Prices, the Partnership is active in supporting its views regarding possible Oklahoma regulatory/legislative action on infill drilling and monitoring activities in the field resulting from removal of production quantity restrictions in the Guymon-Hugoton field.

Kansas 2000 sales volumes were lower than 1999 and 1998 as a result of declining volumes and pressures typical of other producers in that area. The use of field compression, which increased volume initially, helped lessen the decline on an annual basis. During 2000, Kansas adopted new regulatory rules, agreed upon by most producers, to enable the use of field compressors to operate Hugoton field wells at a vacuum and provide that no well will be restricted to less than 100 MCF per day. Possible effects on future production in excess of 100 MCF per day allowed by the state regulations are not predictable. The Partnership has begun receiving approval to operate wells at a vacuum; however, the Partnership does not anticipate any significant change in current production.

The Partnership is continuing to monitor the activity on nearby acreage in the Council Grove formation. At present 15 wells have been drilled by others. Two of the fifteen wells were recompleted in the Guymon-Hugoton field which presently improved production by 0 to 40 MCF per day over the two original Guymon-Hugoton wells that were plugged and abandoned per state regulations. The Partnership's ownership includes the Council Grove formation underlying most of its Oklahoma acreage. **It is not known if such monitoring will result in any plans by the Partnership to attempt a Council Grove well; previous preliminary reviews yielded unfavorable forecasts.** Recent results by others in the 13 remaining wells have varied from 15 MCF per day to 357 MCF per day. Production volumes in subsequent months have varied with most wells showing decreases. Current total production from the three Council Grove wells owned by others but located on the Partnership's acreage is approximately 33 MCFD, 22 MCFD and 10 MCFD. The Partnership has a minor overriding royalty interest in the three wells.

As previously reported, the accounting firm that has, for years, processed the Partnership's 4,000 to 5,000 individualized K-1's notified us that their computer software would not be able to process Year 2000 tax returns in early 2001. Subsequently, the Partnership was notified that the accounting firm had begun developing new software, acquired another firm that had a Year 2000 compliant product, and was preparing for newly required electronic filing of tax year 2000 K-1's with the Internal Revenue Service. Conversion of the data to the Year 2000 compliant product has been performed. Expenditures increased from approximately $176,000 in 1999 to approximately $320,000 in 2000, of which approximately $100,000 could be non-recurring in nature. The Partnership believes it could incur additional non-recurring expenditures during calendar year 2001 on K-1 preparation and/or conversion costs. However, the amount is unpredictable.

As previously discussed in the 1997, 1998 and 1999 Annual Reports, the Partnership is reviewing its strategic alternatives in light of the various mergers and other business transactions occurring in the natural gas and energy industry. Although no decision to sell or combine the Partnership's business with others has been made, the Partnership anticipates possible discussions with third parties which could result in such a decision. The Partnership has no timetable for any such discussions, and there is no assurance that any such discussions will lead to a transaction. During the first quarter of 1998 the Partnership adopted a severance policy which would provide up to approximately $2.8 million of severance payments. Please see Note 3 to the Financial Statements.

FINANCIAL INFORMATION

Financial Statements:

Statements of Earnings for the Years Ended December 31, 2000, 1999 and 1998.

Statements of Comprehensive Income for the Years Ended December 31, 2000, 1999 and 1998.

Balance Sheets as of December 31, 2000 and 1999.

Statements of Changes in Partnership Capital for the Years Ended December 31, 1998, 1999 and 2000.

Statements of Cash Flows for the Years Ended December 31, 2000, 1999 and 1998.

Notes to Financial Statements.

Exhibits:

Number	Description	Previously filed and incorporated with (bearing the same exhibit number)
3	— Amended and Restated Certificate and Agreement of Limited Partnership, as amended	June 30, 1995 Form 10-Q
3.01	— Certificates of Amendments to the Agreement of Limited Partnership dated July 2, 1997 and December 15, 1997	December 31, 1997 Form 10-K
3.02	— Certificate of Amendment to the Agreement of Limited Partnership dated April 3, 1998	March 31, 1998 Form 10-Q
4.1	— Depositary Agreement, as amended	June 30, 1995 Form 10-Q
4.2	— Specimen Depositary Receipt	December 31, 1995 Form 10-K
4.3	— Nominee Agreement among the Partnership, Dorchester and Nominee	December 31, 1995 Form 10-K

All other schedules and exhibits have been omitted because they are either not required, not applicable or the required information is disclosed in the Financial Statements or related Notes. No reports on Form 8-K were filed during the last quarter of the year covered by this report.

REPORT OF INDEPENDENT ACCOUNTANTS

To the General Partners and Unitholders of Dorchester Hugoton, Ltd.:

We have audited the financial statements of Dorchester Hugoton, Ltd. listed under Financial Information above. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Dorchester Hugoton, Ltd. as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

GRANT THORNTON LLP

Dallas, Texas
February 9, 2001

DORCHESTER HUGOTON, LTD.
(A Texas Limited Partnership)

STATEMENTS OF EARNINGS
For the Years Ended December 31, 2000, 1999 and 1998
(Dollars in Thousands)

	Year Ended December 31		
	2000	1999	1998
Net operating revenues:			
Natural gas sales	$26,368	$15,849	$15,901
Other	221	198	199
Production payment (ORRI)	(1,407)	(745)	(734)
Total net operating revenues	25,182	15,302	15,366
Costs and expenses:			
Operating	2,840	2,678	2,619
Production taxes	1,529	910	921
Depreciation, depletion and amortization	1,783	1,903	2,015
General and administrative:			
Tax and regulatory reporting	320	176	143
Depositary and transfer agent fees	22	24	18
Other	448	363	371
Management fees	589	490	491
Interest expense	39	37	40
Other income, net	(350)	(325)	(262)
Total costs and expenses	7,220	6,256	6,356
Net earnings	$17,962	$ 9,046	$ 9,010
Net earnings per Unit	$ 1.66	$ 0.83	$ 0.83

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2000, 1999 and 1998
(Dollars in Thousands)

	Year Ended December 31		
	2000	1999	1998
Net earnings	$17,962	$9,046	$9,010
Unrealized holding gain on available for sale securities	408	476	635
Comprehensive income	$18,370	$9,522	$9,645

See Notes to Financial Statements

DORCHESTER HUGOTON, LTD.
(A Texas Limited Partnership)

BALANCE SHEETS
December 31, 2000 and 1999
(Dollars in Thousands)

ASSETS

	2000	1999
Current assets:		
Cash and cash equivalents	$15,767	$ 7,017
Restricted cash (Note 3)	409	390
Investments — available for sale	5,564	5,156
Accounts receivable	4,092	1,555
Prepaid expenses and other current assets	284	141
Total current assets	26,116	14,259
Property and equipment — at cost:		
Natural gas properties (full cost method)	28,467	28,143
Other	1,122	1,060
Total	29,589	29,203
Less accumulated depreciation, depletion and amortization:		
Full cost depletion	16,534	14,863
Other	462	434
Total	16,996	15,297
Net property and equipment	12,593	13,906
Total assets	$38,709	$28,165

LIABILITIES AND PARTNERSHIP CAPITAL

	2000	1999
Current liabilities:		
Accounts payable	$ 443	$ 252
Production and property taxes payable	996	630
Royalties payable	1,851	889
Distributions payable to unitholders	2,389	1,956
Total current liabilities	5,679	3,727
Notes payable — long-term	100	100
Total liabilities	5,779	3,827
Commitments and contingencies (Note 3)		
Partnership capital:		
General partners	222	140
Unitholders	29,661	21,559
Accumulated other comprehensive income	3,047	2,639
Total partnership capital	32,930	24,338
Total liabilities and partnership capital	$38,709	$28,165

See Notes to Financial Statements

DORCHESTER HUGOTON, LTD.
(A Texas Limited Partnership)

STATEMENTS OF CHANGES IN PARTNERSHIP CAPITAL
For the Years Ended December 31, 1998, 1999 and 2000
(Dollars in Thousands)

Year	General Partners	Unitholders	Accumulated Other Comprehensive Income	Total
1998				
Balance at December 31, 1997	$116	$19,197	$1,528	$20,841
Net earnings	90	8,920	—	9,010
Net unrealized holding gain on investments available for sale	—	—	635	635
Distributions ($0.72 per Unit)	(78)	(7,736)	—	(7,814)
Other	—	(31)	—	(31)
Balance at December 31, 1998	128	20,350	2,163	22,641
1999				
Net earnings	90	8,956	—	9,046
Net unrealized holding gain on investments available for sale	—	—	476	476
Distributions ($0.72 per Unit)	(78)	(7,736)	—	(7,814)
Other	—	(11)	—	(11)
Balance at December 31, 1999	140	21,559	2,639	24,338
2000				
Net earnings	180	17,782	—	17,962
Net unrealized holding gain on investments available for sale	—	—	408	408
Distributions ($0.90 per Unit)	(98)	(9,670)	—	(9,768)
Other	—	(10)	—	(10)
Balance at December 31, 2000	$222	$29,661	$3,047	$32,930

See Notes to Financial Statements

DORCHESTER HUGOTON, LTD.
(A Texas Limited Partnership)

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
(Dollars in Thousands)

	2000	1999	1998
Cash flows from operating activities:			
Net earnings	$17,962	$ 9,046	$ 9,010
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,783	1,903	2,015
Gain on sale of property and equipment	(29)	(8)	(13)
Other	(10)	(11)	(31)
Changes in operating assets and liabilities:			
Restricted cash	(19)	(11)	(379)
Accounts receivable	(2,537)	90	441
Prepaid expenses and other current assets	(143)	11	(16)
Accounts payable, taxes and royalties payable	1,519	25	(526)
Net cash provided by operating activities	18,526	11,045	10,501
Cash flows from investing activities:			
Capital expenditures	(496)	(391)	(1,136)
Purchase of available for sale securities	—	—	(741)
Cash received on sale of property and equipment	54	12	58
Net cash used by investing activities	(442)	(379)	(1,819)
Cash flows from financing activities:			
Loan payments	—	—	(44)
Distributions paid to Unitholders	(9,334)	(7,816)	(7,815)
Net cash used by financing activities	(9,334)	(7,816)	(7,859)
Increase in cash and cash equivalents	8,750	2,850	823
Cash and cash equivalents at beginning of year	7,017	4,167	3,344
Cash and cash equivalents at end of year	$15,767	$ 7,017	$ 4,167
Supplemental cash flow and other information:			
Interest paid (no interest was capitalized)	$ 39	$ 37	$ 43
Distributions declared but not paid	$ 2,389	$ 1,956	$ 1,957

See Notes to Financial Statements

DORCHESTER HUGOTON, LTD.
(A Texas Limited Partnership)

NOTES TO FINANCIAL STATEMENTS
December 31, 2000, 1999 And 1998

1. General and Summary of Significant Accounting Policies

Nature of Operations — The Partnership's operations consist principally of the operation of natural gas properties located in Kansas and Oklahoma.

Basis of Presentation — Per-Unit information is calculated by dividing the 99% interest owned by Unitholders by the 10,744,380 Units outstanding.

Estimates — The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents — The Partnership's principal banking and short-term investing activities are with major financial institutions. Short-term investments with a maturity of three months or less are considered to be cash equivalents and are carried at cost, which approximates fair value. Cash balances in these accounts may, at times, exceed federally insured limits. The Partnership has not experienced any losses in such cash accounts or investments and does not believe it is exposed to any significant risk on cash and cash equivalents.

Concentration of Credit Risks — The Partnership sells its natural gas to major corporate gas purchasers in the United States and performs on-going credit evaluations of its customers, requiring major corporate guarantees, good credit history with the Partnership, or letters of credit on a regular basis. The Partnership has incurred minimal credit losses.

Investments — The Partnership's investments consist of shares of Exxon Mobil Corporation (previously Exxon Corporation) common stock and are classified as available for sale. At December 31, 2000 and 1999, the carrying value of this stock, based on the quoted market price, was $5,564,000 and $5,156,000, respectively, and the cost was $2,517,455 for both years.

Property and Equipment — The Partnership follows the full cost method of accounting prescribed by the United States Securities and Exchange Commission under which all costs relating to the acquisition, exploration and development of natural gas properties (both productive and nonproductive) are capitalized (not to exceed estimated discounted future net cash flows) by the country (United States) in which the costs are incurred. Natural gas properties are being depleted on the unit-of-production method using estimates of proved gas reserves. Other assets are being depreciated or amortized using straight-line methods for financial reporting purposes over estimated useful lives of 3 to 40 years.

Gains or losses are recognized upon the disposition of natural gas properties involving a significant portion of the Partnership's reserves. Proceeds from other dispositions of natural gas properties are credited to the full cost account.

General Partners — The Partnership's General Partners have the overall responsibility for the management, operation and future development of the properties. Each General Partner is entitled to receive reasonable compensation in the form of a management fee, to be divided among the General Partners in an annual aggregate amount of $350,000 plus 1% of the gross income from the Partnership properties for services rendered in operating and managing the Partnership. The General Partners are also reimbursed for all general and administrative expenses incurred by them on behalf of the Partnership.

Operating Agreement — The Partnership operates substantially all of its natural gas properties. Efforts are made to balance each working interest owner's share of production to gas marketed by increasing or decreasing the volumes of gas allocated to each working interest owner in subsequent months so that each such working interest owner shall be able to share in the actual cumulative production in proportion to its interest in the properties. The Partnership receives in-kind the Partnership's share of gas produced from 11 wells in Oklahoma (10 operated by others and 1 operated by the Partnership). At December 31, 2000 the net balance owed the Partnership is less than 300 MCF compared to 14,000 MCF at December 31, 1999.

Other Agreements — Effective May 1, 1997, the Partnership's Kansas gas was committed for sale and processing to PanEnergy Field Services, Inc. (now Duke Energy Field Services, Inc.) for a period of 3 years and year to year thereafter. Duke Energy will pay based on an index of the market price in the field plus a premium. Similarly, effective July 1, 2000 the Partnership's Oklahoma gas was committed for sale to Williams Energy Marketing and Trading Company (''WEM & TC'') for a one-year period at a premium over the market price index. During 1996, the Partnership's Oklahoma gas began a five-year commitment to Williams Field Services Company for delivery through a processing facility. The quantity sold to WEM & TC is determined by nominations at the processing facility outlet. Imbalances with actual deliveries to Williams Field Services Company are corrected in each subsequent month. At December 31, 2000 the imbalance was approximately 7,000 MMBTU owed the Partnership compared to 22,000 MMBTU owed the Partnership at December 31, 1999.

Operating Revenue — Natural gas revenues are recognized as production and sales take place (the ''sales method''). The Partnership's purchasers (including their affiliates) who accounted for more than 10% of natural gas revenues for each of the years ended December 31, 2000, 1999 and 1998 are as follows:

Year	Purchaser ''A''	Purchaser ''B''
2000	83%	16%
1999	80%	19%
1998	76%	23%

The Partnership believes that the loss of any single customer would not have a material adverse effect on the results of its operations because the transmission (and gathering) pipelines connected to the Partnership's facilities are required by the Federal Energy Regulatory Commission or state regulations to provide continued equal access for shipment of natural gas. Additionally, there are numerous buyers available on each pipeline.

Income Taxes — The Partnership is treated as a partnership for income tax purposes and, as a result, income or loss of the Partnership is includible in the tax returns of the individual Unitholders. Accordingly, no recognition has been given to income taxes in the financial statements.

An investment in the Partnership by certain tax-exempt entities (such as IRA's, pension plans, etc.) may produce Unrelated Business Taxable Income (''UBTI''). Many tax-exempt entities are subject to tax on UBTI. Tax exempt entities subject to the tax on UBTI must file with the IRS for each tax year that the entity has gross income of $1,000 or more from an unrelated trade or business. Additionally, the Partnership reports Unitholders' share of depreciation adjustments for alternative minimum tax (''AMT'') purposes. The AMT adjustment must be taken into account when figuring Unitholder passive activity gains and losses for AMT purposes. UBTI and AMT are specialized areas of the tax law — Unitholders should consult tax advisors concerning their own tax situation. Finally, depletion of natural gas properties is an expense allowable to each individual partner and the depletion expense as reported on the financial statements will not be indicative of the depletion expense an individual partner or Unitholder may be able to deduct for income tax purposes.

Simplified Employee Pension Plan — Contributions aggregating $136,065, $135,125, and $134,186 were made to eligible employees' accounts for 2000, 1999, and 1998, respectively under the Partnership's simplified employee pension plan. Employees become eligible in their third calendar year of employment. The Partnership does not have any other post-retirement benefit plans.

Operating Leases — The Partnership rents administrative office space under leases expiring at various dates through 2001. The Partnership also rents nine skid-mounted field gas compressor units on a month to month basis. The Partnership also has various prepaid site leases in Kansas and Oklahoma. Total rental expense was $337,000, $333,000, and $324,000 for the years ended December 31, 2000, 1999, and 1998, respectively.

2. Loans And Long-Term Debt

On July 19, 1994, the Partnership entered into a $15,000,000 unsecured revolving credit facility (the ''Credit Agreement'') with Bank One, Texas, NA (the ''Bank'') which was recently renewed. The current borrowing base is $6,000,000, which will be re-evaluated by the Bank at least semi-annually. If, on any such date, the aggregate amount of outstanding loans and letters of credit exceed the current borrowing base, the Partnership is required to repay the excess. This credit facility includes both cash advances and any letters of credit that the Partnership may need, with interest being charged at the Bank's base rate, which was 9.5% on December 31, 2000. All amounts borrowed under this facility become due and payable on July 31, 2002. As of December 31, 2000, a letter of credit totaling $25,000 was issued under the credit facility and the amount borrowed was $100,000. The Partnership is required to maintain certain minimum defined financial ratios with respect to its current ratio and the ratio of net cash flow to debt service. In addition, Partnership capital must be maintained above specified amounts. This note has been guaranteed by the General Partners. Since July 1994 the maximum amount borrowed under the Credit Agreement has been $5,800,000. During 2000 and 1999 the amount borrowed under the Credit Agreement was $100,000 (the minimum borrowing necessary to maintain the credit facility).

3. Commitments And Contingencies

Since its first annual payment in 1997, each May the Partnership pays an Oklahoma production payment (calculated through the prior February) that is based upon the difference between market gas prices compared to a table of rising prices and based upon a table of declining volumes.

Through 1998 the Partnership recorded $450,000 (which included related interest) towards a request from Panhandle Eastern Pipe Line Company (''PEPL'') for refund of Kansas tax reimbursements received by the Partnership during the years 1983 to 1987. These charges resulted from a ruling by the United States Court of Appeals for the District of Columbia, which overruled a previous order by the Federal Energy Regulatory Commission. On March 9, 1998 $151,757 was paid to PEPL. An additional $366,633, which is still awaiting possible settlement/regulatory/judicial/legislative action, was placed into an escrow account. On March 2, 1999, $2,840 was released from escrow to PEPL. At December 31, 2000, the value of the escrow is approximately $409,000. The escrowed funds include amounts that could possibly be waived, recovered or recoverable from others, of which $34,000 has been recorded as an allowance for bad debt on the Partnership's books in the event it is not waived and deemed uncollectible.

The Partnership is involved in a few other legal and/or administrative proceedings arising in the ordinary course of its gas business, none of which have predictable outcomes and none of which are believed to have any significant effect on financial position or operating results.

The Partnership adopted a severance policy during the first quarter of 1998. Benefits are generally payable to employees and General Partner(s) in the event of a reduction in force or the elimination of a position or group of positions. The policy provides for up to approximately $2.8 million of severance payments if such obligations occur.

4. Unaudited Natural Gas Reserve Information

Proved natural gas reserves are estimated quantities which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The Partnership retained Calhoun, Blair & Associates, Inc., (or its predecessor, Calhoun Engineering, Inc.) an independent petroleum engineering consulting firm, to provide annual estimates as of December 31 of each year of the Partnership's future net recoverable natural gas reserves. The Partnership has no known reserves of crude oil. There have been no events that have occurred since December 31, 2000 that would have a material effect on the estimated proved developed natural gas reserves.

In accordance with SFAS No. 69 and Securities and Exchange Commission (''SEC'') rules and regulations, the following information is presented with regard to the Partnership's gas reserves, all of which are proved, developed and located in the United States.

The SEC has adopted SFAS No. 69 disclosure guidelines for oil and gas producers. These rules require the Partnership to include as a supplement to the basic financial statements a standardized measure of discounted future net cash flows relating to proved oil and gas reserves.

The standardized measure, in management's opinion, should be examined with caution. The basis for these disclosures is an independent petroleum engineer's reserve study which contains imprecise estimates of quantities and rates of production of reserves. Revision of prior year estimates can have a significant impact on the results. Also, exploration and production improvement costs in one year may significantly change previous estimates of proved reserves and their valuation. Values of unproved properties and anticipated future price and cost increases or decreases are not considered. Therefore, the standardized measure is not necessarily a ''best estimate'' of the fair value of the Partnership's gas properties or of future net cash flows.

DORCHESTER HUGOTON, LTD.
(A Texas Limited Partnership)

NOTES TO FINANCIAL STATEMENTS — (Continued)

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves developed by independent petroleum engineers.

Summary of Changes in Proved Developed Reserves

	Natural Gas (MMCF)		
	2000	1999	1998
Estimated quantity, beginning of year	58,209	64,147	71,431
Revisions in previous estimates	3,012	1,478	581
Production	(7,094)	(7,416)	(7,865)
Estimated quantity, end of year	54,127	58,209	64,147
Depletion of natural gas properties (per MCF)	$ 0.24	$ 0.24	$ 0.24
Development costs incurred (in thousands of dollars)	$ 324	$ 348	$ 963
Leasehold acquisitions (in thousands of dollars)	$ 23	$ 16	$ 387

Standardized Measure of Discounted Future Net Cash Flows (Dollars in Thousands)

	2000	1999	1998
Future estimated gross revenues	$313,890	$118,516	$113,517
Future estimated gross production payment (ORRI)	(18,613)	(5,353)	(3,833)
Future estimated production and development costs	(71,661)	(45,930)	(46,245)
Future estimated net revenues	223,616	67,233	63,439
Future estimated net revenues 10% annual discount for estimated timing of cash flows	(83,613)	(22,851)	(22,830)
Standardized measure of discounted future estimated net revenues	$140,003	$ 44,382	$ 40,609
Sales of natural gas produced, net of production costs	$(20,812)	$(11,525)	$(11,633)
Net changes in prices and production costs	108,425	8,717	(8,821)
Revisions of previous quantity estimates	3,964	2,509	488
Accretion of discount	3,932	3,627	4,917
Other	112	445	528
Net change in standardized measure of discounted future estimated net revenues	$ 95,621	$ 3,773	$(14,521)

5. Unaudited Quarterly Financial Data

Quarterly financial data for the last two years (dollars in thousands except per unit data) is summarized as follows:

	2000 Quarter Ended				1999 Quarter Ended			
	March 31	June 30	September 30	December 31	March 31	June 30	September 30	December 31
Net operating revenues	$4,161	$5,572	$7,037	$8,412	$3,064	$3,508	$4,337	$4,393
Net earnings	2,638	3,403	5,239	6,682	1,602	1,889	2,769	2,786
Net earnings per Unit	$ 0.24	$ 0.32	$ 0.48	$ 0.62	$ 0.15	$ 0.17	$ 0.26	$ 0.25

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 15, 2001

DORCHESTER HUGOTON, LTD.

P.A. PEAK, INC., GENERAL PARTNER

By /s/ PRESTON A. PEAK

Preston A. Peak, President
(Principal Executive and Financial Officer)

JAMES E. RALEY, INC., GENERAL PARTNER

By /s/ JAMES E. RALEY

James E. Raley, President
(Principal Executive and Financial Officer)

By /s/ KATHLEEN A. RAWLINGS

Kathleen A. Rawlings, Controller
(Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

P.A. PEAK, INC.

By /s/ PRESTON A. PEAK Preston A. Peak President and Sole Director	General Partner	February 15, 2001

JAMES E. RALEY, INC.

By /s/ JAMES E. RALEY James E. Raley President and Sole Director	General Partner	February 15, 2001

EXHIBIT INDEX

Number	Description	Previously filed and incorporated with (bearing the same exhibit number)
3	— Amended and Restated Certificate and Agreement of Limited Partnership, as amended	June 30, 1995 Form 10-Q
3.01	— Certificates of Amendments to the Agreement of Limited Partnership dated July 2, 1997 and December 15, 1997	December 31, 1997 Form 10-K
3.02	— Certificate of Amendment to the Agreement of Limited Partnership dated April 3, 1998	March 31, 1998 Form 10-Q
4.1	— Depositary Agreement, as amended	June 30, 1995 Form 10-Q
4.2	— Specimen Depositary Receipt	December 31, 1995 Form 10-K
4.3	— Nominee Agreement among the Partnership, Dorchester and Nominee	December 31, 1995 Form 10-K

All other schedules and exhibits have been omitted because they are either not required, not applicable or the required information is disclosed in the Financial Statements or related Notes. No reports on Form 8-K were filed during the last quarter of the year covered by this report.