YEAR 1998

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MONT. P. S. COMMISSION

ANNUAL REPORT
OF

Montana-Dakota Utilities Company

GAS UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

Check No. 834156
Montana-Dakota
Utilities Co

REVISED JULY 28, 1998

Gas Annual Report

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Gas Annual Report

Instructions

General

1. A Microsoft EXCEL 97 workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell.

2. The workbook contains input sections that are unprotected, and non-input sections that are protected. Cell protection can be disabled or enabled through "TOOLS – PROTECTION – UNPROTECT SHEET" on your toolbar. Formulas and checks are built into most of the templates.

3. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed. There are macros built into the workbook to assist you with the report. An explanation of the macros is on the "Control" worksheet at the front of the workbook. The explanations start at cell A1.

4. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed. The orientation and margins are set up on each individual worksheet and should print on one page. If you elect not to use the disk, please format your reports to fit on one 8.5'' by 11'' page with the left binding edge (top if landscaped) set at .85'', the right edge (bottom if landscaped) set at .4'', and the remaining two margins at .5''. You may select specific schedules to print – See the worksheet "CONTROL".

5. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

6. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

7. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

8. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

9. All companies owned by another company shall attach a corporate structure chart of the holding company.

10. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

11. The following schedules shall be filled out with information on a total company basis:

    Schedules 1 through 5
    Schedules 6 and 7
    Schedule 14
    Schedule 17 and 18
    Schedules 23 through 26
    Schedule 33

    All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

    Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

12. For schedules where information may be provided using Mcf or Dkt, circle Mcf or Dkt to indicate which measurement is being reported. (For example, schedules 28, 32, 33 and 34).

13. FERC Form-2 sheets may not be substituted in lieu of completing annual report schedules.

14. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 201 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

2. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 34

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

IDENTIFICATION

Year: **1998**

1.	Legal Name of Respondent:	MDU Resources Group, Inc.
2.	Name Under Which Respondent Does Business:	Montana-Dakota Utilities Co.
3.	Date Utility Service First Offered in Montana	1920
4.	Address to send Correspondence Concerning Report:	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, ND 58501
5.	Person Responsible for This Report:	C. Wayne Fox
5a.	Telephone Number:	(701) 222-7637

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors *

Line No.	Name of Director and Address (City, State) (a)	Remuneration (b)
1	Martin A. White, Bismarck, ND	-
2	Ronald D. Tipton, Bismarck, ND	-
3	Lester H. Loble II, Bismarck, ND	-
4	Stanley E. Wingate, Bismarck, ND	-
5	Bruce T. Imsdahl, Bismarck, ND	-
6	Douglas C. Kane, Bismarck, ND	-
7	Warren L. Robinson, Bismarck, ND **	-
8		
9		
10	* Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc.,	
11	and has no Board of Directors. The affairs of the company are managed by	
12	a Managing Committee, the members of which are provided herein rather	
13	than the directors of MDU Resources Group, Inc.	
14		
15	** Term began November 5, 1998	
20		

Officers

Year: 1998

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President and Chief	Executive	Ronald D. Tipton
2	Executive Officer		
3			
4	Vice President	Regulatory Affairs and	C. Wayne Fox
5		General Services	
6			
7	Vice President	Energy Supply	Bruce T. Imsdahl
8			
9	Assistant Vice President	Gas Supply	Donald F. Klempel
10			
11	Vice President	Marketing and	Ronald G. Skarphol
12		Business Development	
13			
14	Vice President	Operations	Stanley E. Wingate
15			
16	Controller	Accounting and	Craig A. Keller
17		Information Systems	
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Company Name: **Montana-Dakota Utilities Co.**

SCHEDULE 4

CORPORATE STRUCTURE

Year: 1998

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Montana-Dakota Utilities Co.	Utility	$17,409	52.23%
2	(A Division of MDU Resources			
3	Group, Inc.)			
4				
5	WBI Holdings, Inc.	Natural Gas Transmission	20,823	62.48%
6		and Energy Marketing		
7				
8	Knife River Corporation	Construction Materials and	24,499	73.50%
9		Mining		
10				
11	Fidelity Oil Group, Inc.	Oil and Natural Gas	(32,673) 1/	-98.03%
12		Production		
13				
14	Utility Services, Inc.	Installs and repairs electric	3,272	9.82%
15		transmission and distribution		
16		power lines and provides		
17		related supplies and equipment		
50	TOTAL		$33,330	100.00%

1/ Reflects $39.9 million, or 78 cents per common share, in noncash after tax write-downs of oil and natural gas properties.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 1998

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$4,917	7.39%	$61,583
Advertising	Customer Service & Information	Directly Assignable	5,114	10.12%	45,400
	Sales	Directly Assignable	1,601	7.81%	18,896
	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	39	0.11%	35,037
Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	6,972	5.12%	129,248
Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	968	6.50%	13,914
Bank Services	Customer Accounts	Directly Assignable	19,399	21.28%	71,769
	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	21,958	6.77%	302,417
Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,201	5.22%	39,933
Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	38,966	5.50%	669,287
Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	41,251	6.42%	601,428
Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	44,337	5.84%	714,820

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 1998

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	2,520	6.21%	38,086
Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,053	6.31%	45,313
Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	12,137	5.58%	205,475
Express Mail	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	242	5.82%	3,915
Freight	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3	11.11%	24
Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	57,206	6.54%	817,430
Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	62	5.83%	1,002
Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	7,763	5.87%	124,553
Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	4,744	6.42%	69,111
Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	4,213	6.08%	65,117
Office Telephone	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	25	5.92%	397
Moving Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	4,935	6.53%	70,643

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 1998

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	211,372	15.69%	1,135,759
4	Printing	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	6,427	5.84%	103,626
7	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	(199)	-6.00%	3,514
10	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	912	5.86%	14,651
13	Payroll	Gas Distribution	Directly Assignable	(60)	31.41%	(131)
15		Customer Accounts	Directly Assignable	(25)	19.23%	(105)
17		Sales	Directly Assignable	(5)	25.00%	(15)
19		Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	419,577	6.42%	6,117,483
22	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	485	7.61%	5,890
25	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	6,834	5.90%	108,991
28	Seminars & Meeting Registrations	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	3,951	6.10%	60,856
31	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,547	9.22%	25,077
34	TOTAL			$936,442	7.40%	$11,720,394

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**WBI HOLDINGS, INC**	Natural Gas	Actual Costs Incurred			
2		Purchases/Transportation		$53,129,775		$16,634,205
3		Refunds/Adjustments		(3,758,227)		(1,102,817)
4						
5						
6						
7						
8						
9		Expense	Actual Costs Incurred			
10		Contract Services		7,032		2,799
11		Meals & Entertainment		16		5
12		Reimbursable Expenses		761		235
13		Employee Benefits		59		59
14		Seminars & Meeting Registrations		900		266
15		Materials		1,775		1,775
16		Office Expenses		260		80
17		Rents		20		
18						
19		Capital		38,442		
20						
21		Other Transactions/Reimbursements				
22		Miscellaneous		187		
23						
24						
25						
26						
27						
28		Total WBI Operating Revenues for the Year 1998			$142,585,652	
29						
30						
31						
32	**TOTAL**	**Grand Total Affiliate Transactions**		$49,421,000	34.6606%	$15,536,607

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	FIDELITY OIL GROUP	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$4,451		
4		Advertising	Costs Incurred	1,550		
5		Air Service		15,654		
6		Automobile		534		
7		Bank Services		22,936		
8		Corporate Aircraft		4,018		
9		Consultant Fees		60,309		
10		Contract Services		39,582		
11		Directors Expenses		69,842		
12		Employee Benefits		3,973		
13		Employee Meeting		2,116		
14		Employee Reimbursable Expense		22,900		
15		Express Mail		383		
16		Freight		1		
17		Legal Retainers & Fees		118,722		
18		Moving Allowance		7,866		
19		Meal Allowance		98		
20		Cash Donations		4,022		
21		Meal & Entertainment		11,137		
22		Industry Dues & Licenses		4,836		
23		Office Expenses		6,279		
24		Office Telephone		39		
25		Supplemental Insurance		18,485		
26		Permits & Filing Fees		567		
27		Postage		1,420		
28		Payroll		541,828		
29		Printing		10,125		
30		Reference Materials		9,722		
31		Rental		223		
32		Seminars & Meeting Registrations		5,561		
33		Software Maintenance		1,467		
34		Training Material		2,540		
35		**Total MDU Resources Group, Inc.**		$993,186	2.4703%	

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	FIDELITY OIL GROUP	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and /or Actual Costs Incurred			
3		Automobile		2		
4		Air Service		11		
5		Contract Services		14		
6		Corporate Aircraft		12		
7		Employee Reimbursable Expense		40		
8		Materials		32		
9		Meals & Entertainment		4		
10		Industry Dues & Licenses		6		
11		Office Expenses		70		
12		Office Telephone		6,980		
13		Payroll		1,506		
14		Reference Material		2		
15		Seminars & Meeting Registrations		5		
16						
17		Office Services	* General Office Complex and Office Supplies Cost of Service Allocation Factors			
18		Automobile		10		
19		Contract Services		346		
20		Employee Meetings		27		
21		Express Mail		1,505		
22		Office Expenses		1,962		
23		Postage		4,830		
24		Cost of Service - General Office Buildings		132,718		$32,372
25						
26		Information Systems	* Various Corporate Overhead Allocation Factors and /or Actual Costs Incurred			
27		Automobile		13		
28		Air Service		7		
29		Contract Services		496		
30		Corporate Aircraft		3		
31		Employee Reimbursable Expense		9		
32		Materials		3		
33		Meals & Entertainment		2		
34		Office Expenses		4,676		
35		Office Telephone		501		

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	FIDELITY OIL GROUP	Payroll		2,469		
2		Permits & Filing Fees		9		
3		Reference Material		5		
4		Seminars & Meeting Registrations		37		
5		Training Material		979		
6						
7		Controller	* Corporate Overhead Allocation Factors			
8		Employee Benefits	Based on Number of Employees	32		
9		Payroll		5		
10						
11		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
12		Automobile	Factors, Time Studies and/or	12		
13		Corporate Aircraft	Actual Costs Incurred	23		
14		Employee Benefits		25		
15		Office Expenses		52		
16		Payroll		972		
17		Training Material		6		
18						
19		Other Direct Charges	Actual Costs Incurred			
20		Utility Discounts		4,129		
21		Merchandise Discounts		316		
22		Corporate Aircraft		3,330		
23		Telephone		4,080		
24		Miscellaneous		4,806		
25						
26						
27						
28						
29						
30		**Total Montana-Dakota Utilities Co.**		$177,079	0.4404%	$32,372

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	FIDELITY OIL GROUP	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Insurance	Actual Costs Incurred			
3		Federal & State Tax Liability Payments		$94,908		
4		KESOP carrying costs		1,722,081		
5		Interest		112,637		
6		SISP Transfer		(1,815)		
7		Pension and FAS Accrual		235,751		
8		Tax Deferred Savings Plan		51,000		
9				1,477		
10		**Total Other Transactions/Reimbursements**				
11				$2,216,039	5.5119%	
12		**Grand Total Affiliate Transactions**				
13				$3,386,304	8.4227%	$32,372
14						
15						
16		**Total Fidelity Oil Group Operating Expenses for 1998**			$40,204,455	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and 'Montana-Dakota Utilities payroll allocated to affiliated companies of the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

Company Name: **Montana-Dakota Utilities Co.**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

SCHEDULE 7

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead				
3						
4		Audit Costs	* Various Corporate Overhead Allocation Factors, Time Studies and/or Actual Costs Incurred	$10,802		
5		Advertising		3,052		
6		Air Service		29,127		
7		Automobile		844		
8		Bank Services		46,340		
9		Corporate Aircraft		6,125		
10		Consultant Fees		113,707		
11		Contract Services		100,193		
12		Directors Expenses		139,685		
13		Employee Benefits		8,130		
14		Employee Meeting		8,081		
15		Employee Reimbursable Expense		42,959		
16		Express Mail		764		
17		Freight		1		
18		Legal Retainers & Fees		126,213		
20		Moving Allowance		12,275		
21		Meal Allowance		196		
22		Cash Donations		7,823		
23		Meal & Entertainment		21,239		
24		Industry Dues & Licenses		9,102		
25		Office Expenses		12,383		
26		Office Telephone		78		
27		Supplemental Insurance		169,165		
28		Permits & Filing Fees		1,120		
29		Postage		2,834		
30		Payroll		988,368		
31		Printing		20,250		
32		Reference Materials		21,446		
33		Rental		223		
34		Seminars & Meeting Registrations		10,869		
35		Software Maintenance		2,935		
36		Training Material		5,079		
		Total MDU Resources Group, Inc.		$1,921,408	0.6303%	

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department				
3		Automobile	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and /or Actual Costs Incurred	$4		
4		Air Service		20		
5		Contract Services		25		
6		Corporate Aircraft		20		
7		Employee Reimbursable Expense		69		
8		Materials		55		
9		Meals & Entertainment		7		
10		Industry Dues & Licenses		11		
11		Office Expenses		94		
12		Office Telephone		12,215		
13		Payroll		2,635		
14		Reference Material		3		
15		Seminars & Meeting Registrations		8		
16						
17		Office Services				
18		Automobile	* General Office Complex and Office Supplies cost of Service Allocation Factors	21		
19		Contract Services		627		
20		Employee Meetings		49		
21		Express Mail		3,010		
22		Office Expenses		3,489		
23		Postage		9,085		
24		Cost of Service - General Office Buildings		246,010		$60,005
25						
26		Information Systems				
27		Automobile	* Various Corporate Overhead Allocation Factors and /or Actual Costs Incurred	10		
28		Air Service		27		
29		Contract Services		387		
30		Corporate Aircraft		18		
31		Employee Meetings		1		
32		Employee Reimbursable Expense		33		
33		Materials		6		
34		Meals & Entertainment		3		
35		Office Expenses		3,678		
36		Office Telephone		618		

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	Payroll		1,809		
2		Permits & Filing Fees		18		
3		Reference Material		3		
4		Seminars & Meeting Registrations		65		
5		Training Material		1,944		
6						
7		Controller	* Corporate Overhead Allocation Factors			
8		Employee Benefits	Based on Number of Employees	1,433		
9						
10		Other Miscellaneous Departments				
11		Automobile		22		
12		Corporate Aircraft		61		
13		Employee Benefits		19		
14		Office Expenses		105		
15		Payroll		1,660		
16		Training Material		5		
17						
18		Other Direct Charges	Actual Costs Incurred			
19		Utility Discounts		63,815		6,364
20		Merchandise Discounts		761		
21		Corporate/Commercial Air Service		11,360		
22		Contract Services		146,575		
23		Office Supplies & Printing		8,239		
24		Rubber Glove Testing		3,757		
25		Electric Consumption		1,673,962		110,271
26		Gas Consumption		1,798		
27		Telephone		14,553		
28		Miscellaneous		6,841		
29						
30						
31						
32						
33						
34						
35		**Total Montana-Dakota Utilities Co.**		$2,221,043	0.7286%	$176,640

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Insurance		$525,850		
3		Federal & State Tax Liability Payments		10,285,284		
4		KESOP carrying costs		566,807		
5		Tax Deferred Savings Plan		26,569		
6		Interest		(3,631)		
7		Miscellaneous Reimbursements		9,487		
8						
9		**Total Other Transactions/Reimbursements**		$11,410,366	3.7430%	
10						
11		**Grand Total Affiliate Transactions**		$15,552,817	5.1019%	$176,640
12						
13						
14						
15		**Total Knife River Corporation Operating Expenses for 1998**			$304,841,842	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and 'Montana-Dakota Utilities payroll allocated to affiliated companies of the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$10,457		
4		Advertising	Costs Incurred	3,631		
5		Air Service		23,835		
6		Automobile		3,767		
7		Bank Services		47,205		
8		Corporate Aircraft		10,674		
9		Consultant Fees		155,758		
10		Contract Services		94,343		
11		Directors Expenses		142,722		
12		Employee Benefits		8,570		
13		Employee Meeting		11,129		
14		Employee Reimbursable Expense		39,958		
15		Express Mail		787		
16		Freight		2		
17		Legal Retainers & Fees		114,653		
18		Moving Allowance		15,923		
19		Meal Allowance		200		
20		Cash Donations		9,325		
21		Meal & Entertainment		26,073		
22		Industry Dues & Licenses		13,369		
23		Office Expenses		13,743		
24		Office Telephone		79		
25		Supplemental Insurance		170,866		
26		Permits & Filing Fees		1,145		
27		Postage		2,937		
28		Payroll		1,281,524		
29		Printing		20,690		
30		Reference Materials		21,795		
31		Rental		1,551		
32		Seminars & Meeting Registrations		13,273		
33		Software Maintenance		3,003		
34		Training Material		5,197		
35		**Total MDU Resources Group, Inc.**		$2,268,184	1.5908%	

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Information Systems	* Various Corporate Overhead Allocation			
2		Expense	Factors and /or Actual Costs Incurred			
3		Automobile		25		
4		Air Service		151		
5		Contract Services		5,002		
6		Corporate Aircraft		78		
7		Industry Dues & Licenses		10		
8		Employee Benefits		3		
9		Employee Meetings		4		
10		Employee Reimbursable Expense		181		
11		Materials		8		
12		Meals & Entertainment		38		
13		Office Expenses		47,573		
14		Office Telephone		3,674		
15		Payroll		17,225		
16		Permits & Filing Fees		19		
17		Reference Material		86		
18		Seminars & Meeting Registrations		392		
19		Training Material		2,125		
20						
21		Controller	* Corporate Overhead Allocation Factors			
22		Expense	Based on Number of Employees			
23		Employee Benefits		1,046		
24						
25		Division Operations	Actual Costs Incurred			
26		Expense				
27		Automobile		3,217		
28		Contract Services		6		
29		Employee Reimbursable Expense		16		
30		Freight		6		
31		Materials		85		
32		Meals & Entertainment		8		
33		Office Expenses		2		
34		OfficeTelephone		46		
35		Payroll		11,966		
36		Utilities		217		

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Transportation Department	* Various Corporate Overhead Allocation			
2		Capital	Factors, Time Studies and /or Actual			
3		Payroll	Costs incurred	10,218		
4		Clearing Accounts				
5		Automobile		1,149		
6		Air Service		59		
7		Contract Services		319		
8		Corporate Aircraft		120		
9		Employee Reimbursable Expense		533		
10		Materials		1,015		
11		Meals & Entertainment		320		
12		Office Expenses		19		
13		Office Telephone		355		
14		Payroll		10,720		
15		Permits & Filing Fees		8		
16		Reference Material		1		
17		Utilities		141		
18						
19		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
20		Expense	Factors, Time Studies and /or Actual			
21		Automobile	Costs incurred	46		
22		Annual Easements		218		
23		Corporate Aircraft		220		
24		Employee Benefits		30		
25		Freight		3		
26		Materials		(20)		
27		Office Expenses		107		
28		OfficeTelephone		14		
29		Payroll		7,209		
30		Utilities		8		
31		Capital				
32		Automobile		10		
33		Air Service		121		
34		Corporate Aircraft		2,851		
35		Employee Reimbursable Expense		794		

Company Name: Montana-Dakota Utilities Co.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

SCHEDULE 7

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Meals & Entertainment		159		
2		Office Expenses		24		
3		Payroll		1,030		
4		Reference Material		76		
5		Seminars & Meeting Registrations		494		
6						
7		Other Direct Charges				
8		Utility/Merchandise Discounts	Actual Costs Incurred	95,743		62,758
9		Corporate Aircraft		85,899		
10		Commercial Air Service		4,880		
11		Contract Services		44,429		
12		Dispatch Services		1,560		
13		Cathodic Protection		13,821		4,036
14		Purchased Power for Compressor Stations		71,572		64,132
15		Electric Compressor - Electricity Cost		138,864		101,374
16		Office Building Utilities		72,341		69,324
17		Office Building Rents		3,966		
18		Telephone		21,100		
19		Miscellaneous		17,029		
20		Nomination Services		112		
21		Pool Car Usage		19,396		
22						
23						
24		Total Montana-Dakota Utilities Co. 1/		$1,445,640	1.0139%	$439,068
25						
26						
27		1 Total Montana-Dakota Charges By Category				
28		Expense		$1,388,851	0.9740%	
29		Capital		42,030	0.0295%	
30		Clearing		14,759	0.0104%	
31		Total		$1,445,640	1.0139%	
32						
33						
34						
35						

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Insurance	Actual Costs Incurred	$181,803		
3		Federal & State Tax Liability Payments		5,123,416		
4		Dividends on Preferred Stock of WBI		572,000		$139,429
5		Tax Deferred Savings Plan		25,080		
6		KESOP carrying costs		252,040		
7		Interest		(3,709)		
8		Miscellaneous Reimbursements		5,175		
9						
10		**Total Other Transactions/Reimbursements**		$6,155,805	4.3173%	$139,429
11						
12		**Grand Total Affiliate Transactions**		$9,869,629	6.9219%	$578,497
13						
14						
15						
16		**Total WBI Holdings Operating Expenses for 1998**			$142,585,652	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and 'Montana-Dakota Utilities payroll allocated to affiliated companies of the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1998

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES INC.	Other Direct Charges	Actual Costs Incurred			
2		Legal Fees		$183,049		
3		Corporate Aircraft		18,373		
4		Commercial Air Service		19,790		
5		Audit Fees		3,502		
6		Miscellaneous		36,035		
7		Meals & Entertainment		5,162		
8		Other Reimbursable Expense		12,542		
9						
10		Other Transactions/Reimbursements				
11		Insurance		164,919		
12		Federal & State Tax Liability Payments		2,117,072		
13						
14						
15						
16		**Grand Total Affiliate Transactions**		$2,560,444	4.3919%	
17						
18						
19						
20						
21						
22						
23						
24						
25		**Total Utility Services Inc. Operating Expenses for 1998**			$58,299,271	

Company Name: Montana-Dakota Utilities Co.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1998

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses - continued**			
2				
3	Exploration & Development - Operation			
4	795 Delay Rentals			
5	796 Nonproductive Well Drilling		NOT	
6	797 Abandoned Leases		APPLICABLE	
7	798 Other Exploration			
8	**TOTAL Exploration & Development**			
9				
10	Other Gas Supply Expenses - Operation			
11	800 Natural Gas Wellhead Purchases			
12	800.1 Nat. Gas Wellhead Purch., Intracomp. Trans.			
13	801 Natural Gas Field Line Purchases			
14	802 Natural Gas Gasoline Plant Outlet Purchases			
15	803 Natural Gas Transmission Line Purchases			
16	804 Natural Gas City Gate Purchases	$26,015,237	$30,528,981	17.35%
17	805 Other Gas Purchases			
18	805.1 Purchased Gas Cost Adjustments	4,351,087	(771,830)	-117.74%
19	805.2 Incremental Gas Cost Adjustments			
20	806 Exchange Gas			
21	807.1 Well Expenses - Purchased Gas			
22	807.2 Operation of Purch. Gas Measuring Stations			
23	807.3 Maintenance of Purch. Gas Measuring Stations			
24	807.4 Purchased Gas Calculations Expenses			
25	807.5 Other Purchased Gas Expenses			
26	808.1 Gas Withdrawn from Storage -Dr.	3,926,734	4,136,770	5.35%
27	808.2 (Less) Gas Delivered to Storage -Cr.	(5,109,649)	(3,749,459)	26.62%
28	809.2 (Less) Deliveries of Nat. Gas for Processing-Cr.			
29	810 (Less) Gas Used for Compressor Sta. Fuel-Cr.			
30	811 (Less) Gas Used for Products Extraction-Cr.			
31	812 (Less) Gas Used for Other Utility Operations-Cr.	(57,860)	(41,749)	27.84%
32	813 Other Gas Supply Expenses	124,139	130,728	5.31%
33	**TOTAL Other Gas Supply Expenses**	$29,249,688	$30,233,441	3.36%
34				
35	**TOTAL PRODUCTION EXPENSES**	$29,249,688	$30,233,441	3.36%

Company Name: Montana-Dakota Utilities Co.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1998

	Account Number & Title	Last Year	This Year	% Change
1	**Storage, Terminaling & Processing Expenses**			
2				
3	Underground Storage Expenses - Operation			
4	814 Operation Supervision & Engineering			
5	815 Maps & Records			
6	816 Wells Expenses			
7	817 Lines Expenses			
8	818 Compressor Station Expenses			
9	819 Compressor Station Fuel & Power		NOT	
10	820 Measuring & Reg. Station Expenses		APPLICABLE	
11	821 Purification Expenses			
12	822 Exploration & Development			
13	823 Gas Losses			
14	824 Other Expenses			
15	825 Storage Well Royalties			
16	826 Rents			
17	**Total Operation - Underground Strg. Exp.**			
18				
19	Underground Storage Expenses - Maintenance			
20	830 Maintenance Supervision & Engineering			
21	831 Maintenance of Structures & Improvements			
22	832 Maintenance of Reservoirs & Wells			
23	833 Maintenance of Lines			
24	834 Maintenance of Compressor Station Equip.		NOT	
25	835 Maintenance of Meas. & Reg. Sta. Equip.		APPLICABLE	
26	836 Maintenance of Purification Equipment			
27	837 Maintenance of Other Equipment			
28	**Total Maintenance - Underground Storage**			
29	**TOTAL Underground Storage Expenses**			
30				
31	Other Storage Expenses - Operation			
32	840 Operation Supervision & Engineering			
33	841 Operation Labor and Expenses			
34	842 Rents		NOT	
35	842.1 Fuel		APPLICABLE	
36	842.2 Power			
37	842.3 Gas Losses			
38	**Total Operation - Other Storage Expenses**			
39				
40	Other Storage Expenses - Maintenance			
41	843.1 Maintenance Supervision & Engineering			
42	843.2 Maintenance of Structures & Improvements			
43	843.3 Maintenance of Gas Holders			
44	843.4 Maintenance of Purification Equipment		NOT	
45	843.6 Maintenance of Vaporizing Equipment		APPLICABLE	
46	843.7 Maintenance of Compressor Equipment			
47	843.8 Maintenance of Measuring & Reg. Equipment			
48	843.9 Maintenance of Other Equipment			
49	**Total Maintenance - Other Storage Exp.**			
50	**TOTAL - Other Storage Expenses**			
51				
52	**TOTAL - STORAGE, TERMINALING & PROC.**			

Company Name: Montana-Dakota Utilities Co.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1998

		Account Number & Title	Last Year	This Year	% Change
1		**Transmission Expenses**			
2	Operation				
3	850	Operation Supervision & Engineering			
4	851	System Control & Load Dispatching			
5	852	Communications System Expenses			
6	853	Compressor Station Labor & Expenses			
7	854	Gas for Compressor Station Fuel		NOT	
8	855	Other Fuel & Power for Compressor Stations		APPLICABLE	
9	856	Mains Expenses			
10	857	Measuring & Regulating Station Expenses			
11	858	Transmission & Compression of Gas by Others			
12	859	Other Expenses			
13	860	Rents			
14		**Total Operation - Transmission**			
15	Maintenance				
16	861	Maintenance Supervision & Engineering			
17	862	Maintenance of Structures & Improvements			
18	863	Maintenance of Mains			
19	864	Maintenance of Compressor Station Equip.		NOT	
20	865	Maintenance of Measuring & Reg. Sta. Equip.		APPLICABLE	
21	866	Maintenance of Communication Equipment			
22	867	Maintenance of Other Equipment			
23		**Total Maintenance - Transmission**			
24		**TOTAL Transmission Expenses**			
25		**Distribution Expenses**			
26	Operation				
27	870	Operation Supervision & Engineering	$362,049	$331,078	-8.55%
28	871	Distribution Load Dispatching	72,065	50,577	-29.82%
29	872	Compressor Station Labor and Expenses			
30	873	Compressor Station Fuel and Power			
31	874	Mains and Services Expenses	582,643	681,923	17.04%
32	875	Measuring & Reg. Station Exp.-General	28,408	22,575	-20.53%
33	876	Measuring & Reg. Station Exp.-Industrial	15,650	7,822	-50.02%
34	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.		27	100.00%
35	878	Meter & House Regulator Expenses	556,003	316,251	-43.12%
36	879	Customer Installations Expenses	769,945	673,785	-12.49%
37	880	Other Expenses	370,035	644,375	74.14%
38	881	Rents	9,964	14,007	40.58%
39		**Total Operation - Distribution**	$2,766,762	$2,742,420	-0.88%
40	Maintenance				
41	885	Maintenance Supervision & Engineering	$153,925	$139,932	-9.09%
42	886	Maintenance of Structures & Improvements	146	692	373.97%
43	887	Maintenance of Mains	182,399	191,522	5.00%
44	888	Maint. of Compressor Station Equipment			
45	889	Maint. of Meas. & Reg. Station Exp.-General	25,154	29,407	16.91%
46	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	16,104	12,071	-25.04%
47	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892	Maintenance of Services	112,015	104,409	-6.79%
49	893	Maintenance of Meters & House Regulators	118,118	98,719	-16.42%
50	894	Maintenance of Other Equipment	26,622	71,017	166.76%
51		**Total Maintenance - Distribution**	$634,483	$647,769	2.09%
52		**TOTAL Distribution Expenses**	$3,401,245	$3,390,189	-0.33%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1998

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Customer Accounts Expenses**			
3	Operation			
4	901 Supervision	$117,894	$101,775	-13.67%
5	902 Meter Reading Expenses	394,180	392,698	-0.38%
6	903 Customer Records & Collection Expenses	988,522	1,005,712	1.74%
7	904 Uncollectible Accounts Expenses	147,588	116,010	-21.40%
8	905 Miscellaneous Customer Accounts Expenses	156,524	184,008	17.56%
9				
10	**TOTAL Customer Accounts Expenses**	$1,804,708	$1,800,203	-0.25%
11				
12	**Customer Service & Informational Expenses**			
13	Operation			
14	907 Supervision	$525	$73	-86.10%
15	908 Customer Assistance Expenses	21,841	19,635	-10.10%
16	909 Informational & Instructional Advertising Exp.	32,654	12,575	-61.49%
17	910 Miscellaneous Customer Service & Info. Exp.	459	319	-30.50%
18				
19	**TOTAL Customer Service & Info. Expenses**	$55,479	$32,602	-41.24%
20				
21	**Sales Expenses**			
22	Operation			
23	911 Supervision	$103,438	$90,190	-12.81%
24	912 Demonstrating & Selling Expenses	184,632	170,343	-7.74%
25	913 Advertising Expenses	20,144	22,122	9.82%
26	916 Miscellaneous Sales Expenses	20,506	20,023	-2.36%
27				
28	**TOTAL Sales Expenses**	$328,720	$302,678	-7.92%
29				
30	**Administrative & General Expenses**			
31	Operation			
32	920 Administrative & General Salaries	$765,065	$772,430	0.96%
33	921 Office Supplies & Expenses	363,819	339,179	-6.77%
34	922 (Less) Administrative Expenses Transferred - Cr.			
35	923 Outside Services Employed	103,563	104,459	0.87%
36	924 Property Insurance	20,633	20,468	-0.80%
37	925 Injuries & Damages	270,207	259,723	-3.88%
38	926 Employee Pensions & Benefits	1,209,695	1,218,179	0.70%
39	927 Franchise Requirements			
40	928 Regulatory Commission Expenses	101,340	77,803	-23.23%
41	929 (Less) Duplicate Charges - Cr.			
42	930.1 General Advertising Expenses	1,635	3,724	127.77%
43	930.2 Miscellaneous General Expenses	108,685	127,876	17.66%
44	931 Rents	15,898	7,215	-54.62%
45				
46	**TOTAL Operation - Admin. & General**	$2,960,540	$2,931,056	-1.00%
47	Maintenance			
48	935 Maintenance of General Plant	$141,944	$138,992	-2.08%
49				
50	**TOTAL Administrative & General Expenses**	$3,102,484	$3,070,048	-1.05%
51	**TOTAL OPERATION & MAINTENANCE EXP.**	$37,942,324	$38,829,161	2.34%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 11

MONTANA TAXES OTHER THAN INCOME

Year: 1998

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$401,308	$405,437	1.03%
2	Superfund			
3	Secretary of State	134	206	53.73%
4	Montana Consumer Counsel	34,484	34,572	0.26%
5	Montana PSC	86,546	104,956	21.27%
6	Franchise Taxes	16,246	16,624	2.33%
7	Property Taxes	1,199,319	1,297,509	8.19%
8	Tribal Taxes	5,519	5,838	5.78%
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50	TOTAL MT Taxes other than Income	$1,743,556	$1,865,142	6.97%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 12

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 1998

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	ABB C-E Services, Inc.	Construction Services			
2			$296,282	$0	0.00%
3	Ace Electric, Inc.	Construction Services			
4			101,660	101,660	100.00%
5	API Construction Company	Construction Services			
6			88,425	0	0.00%
7	Applied Control	Construction Services			
8			211,896	0	0.00%
9	Arthur Andersen LLP	Audit Service			
10			195,100	10,774	5.52%
11	Baranko Brothers, Inc.	Construction Services			
12			158,376	0	0.00%
13	Bullinger Tree Service	Tree Trimming Service			
14			157,251	0	0.00%
15	Chief Construction	Construction Services			
16			337,133	0	0.00%
17	Customerlink	Telemarketing Service			
18			90,035	0	0.00%
19	Daksoft, Inc.	Consultant - CIS System			
20			835,923	82,850	9.91%
21	Diversified Graphics, Inc.	Contract Services - Annual Report			
22			93,279	5,448	5.84%
23	Gagnon, Inc.	Construction Services			
24			116,609	0	0.00%
25	Hedahl's of Bismarck	Contract Services - Auto and Work Equip.			
26			141,222	301	0.21%
27	Horsley Specialties	Construction Services - Asbestos Removal			
28			177,664	0	0.00%
29	Industrial Contractors, Inc.	Construction Services			
30			115,930	0	0.00%
31	Itec Enterprises, Inc.	Construction Services			
32			114,381	0	0.00%
33	Jim's Water Service, Inc.	Construction Services			
34			104,451	16	0.02%
35	Leboeuf, Lamb, Greene &	Legal Services			
36			83,871	4,898	5.84%
37	New York Stock Exchange	Contract Services - Financial			
38			107,763	6,093	5.65%
39	Norwest Bank	Stock Transfer Agent			
40			224,394	15,041	6.70%
41	Olszeweski, Inc.	Coyote Station Ash Hauling			
42			228,466	0	0.00%
43	One Call Locators, Inc.	Line Location Service			
44			76,690	76,690	100.00%
45	Osmose Wood	Contract Services - Pole Treatment			
46			223,098	0	0.00%
47	Prime Power & Communication	Construction Services			
48			129,516	0	0.00%
49	Progressive Maintenance	Contract Services - Custodial			
50			113,785	21,958	19.30%
51	Southern Cross Corporation	Contract Services - Leak Detection			
52			126,008	25,889	20.55%

Company Name: **Montana-Dakota Utilities Co.**

SCHEDULE 12

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 1998

1	Sterling Software	Consultant - CIS System	465,199	49,262	10.59%
2					
3	Strategic Capital, Inc.	Consultant - Financial	124,679	5,781	4.64%
4					
5	Thelen, Reid, & Priest LLP	Legal Services	880,203	25,514	2.90%
6					
7	Towers Perrin	Consultant - Compensation and Benefits	345,510	25,307	7.32%
8					
9	Underground Locator's, Inc.	Line Location Service	90,165	0	0.00%
10					
11	Underground Utility	Line Location Service	141,968	36	0.03%
12					
13	US Bank	Bank Services	122,193	21,982	17.99%
14					
15	Utility Partners, LC	Consultant - Mobile Service Computer	188,670	19,976	10.59%
16					
17	Vadakin, Inc.	Construction Services	116,103	0	0.00%
18					
19	Wang Laboratories, Inc.	Contract Services - Computer System	108,963	17,207	15.79%
20					
21	West Star Aviation, Inc.	Contract Services - Plane Refurbishing	440,157	42,452	9.64%
22					
23	**TOTAL Payments for Services**		$7,673,018	$559,135	7.29%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 13

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

Year: 1998

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$22,025	$2,600	11.80%
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50	**TOTAL Contributions**	$22,025	$2,600	11.80%

Pension Costs

Year: 1998

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: 1		
4	Annual Contribution by Employer: 0	Is the Plan Over Funded? Yes		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$126,985	$116,007	9.46%
8	Service cost	3,055	2,679	14.04%
9	Interest Cost	8,838	8,619	2.54%
10	Plan participants' contributions	-	-	
11	Amendments	-	-	
12	Actuarial Gain	4,111	7,300	-43.68%
13	Acquisition	-	-	
14	Benefits paid	(8,227)	(7,620)	-7.97%
15	Benefit obligation at end of year	$134,762	$126,985	6.12%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$164,330	$143,122	14.82%
18	Actual return on plan assets	30,053	28,828	4.25%
19	Acquisition	-	-	
20	Employer contribution	-	-	
21	Plan participants' contributions	-	-	
22	Benefits paid	(8,227)	(7,620)	-7.97%
23	Fair value of plan assets at end of year	$186,156	$164,330	13.28%
24	**Funded Status**	$51,394	$37,345	37.62%
25	Unrecognized net actuarial loss	(57,917)	(44,001)	-31.63%
26	Unrecognized prior service cost	5,398	6,001	-10.05%
27	Unrecognized net transition obligation	(4,423)	(5,275)	16.15%
28	Prepaid (accrued) benefit cost	($5,548)	($5,930)	6.44%
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	6.75	7.00	-3.57%
32	Expected return on plan assets	8.50	8.50	
33	Rate of compensation increase	4.50	4.50	
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	$3,055	$2,679	14.04%
37	Interest cost	8,838	8,619	2.54%
38	Expected return on plan assets	(11,637)	(10,688)	-8.88%
39	Amortization of prior service cost	604	604	
40	Recognized net actuarial loss	(390)	(440)	11.36%
41	Transition amount amortization	(852)	(852)	
42	Net periodic benefit cost	($382)	($78)	-389.74%
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs	($382)	($78)	-389.74%
46	Pension Costs Capitalized	(4)	(4)	
47	Accumulated Pension Asset (Liability) at Year End	(5,548)	(5,930)	6.44%
48	**Number of Company Employees:**			
49	Covered by the Plan	1,974	2,007	-1.64%
50	Not Covered by the Plan	13	19	-31.58%
51	Active	1,140	1,166	-2.23%
52	Retired	801	806	-0.62%
53	Deferred Vested Terminated	33	35	-5.71%

Other Post Employment Benefits (OPEBS)

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: 95.7.90			
4	Order numbers: 5856b & 5856g			
5	Amount recovered through rates - $453,658			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	6.75	7.00	-3.57%
8	Expected return on plan assets	7.50	7.50	
9	Medical Cost Inflation Rate	7.00	8.00	-12.50%
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase	4.50	4.50	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	VEBA			
14	**Describe any Changes to the Benefit Plan:** If an employee is at least age 55 and completed at least 10			
15	continuous years of service with the Company immediately prior to retirement, the contributory life insurance			
16	may be continued as a retiree benefit. For retirements effective January 1, 1999 and forward, the amount of			
17	contributory life insurance will be 25% of the amount in effect immediately prior to retirement.			
	TOTAL COMPANY			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	$52,366	$52,285	0.15%
20	Service cost	984	875	12.46%
21	Interest Cost	3,444	3,516	-2.05%
22	Plan participants' contributions	413	324	27.47%
23	Amendments	(4,137)	-	-100.00%
24	Actuarial Gain	(1,120)	(1,771)	36.76%
25	Acquisition	-	-	
26	Benefits paid	(2,865)	(2,863)	-0.07%
27	Benefit obligation at end of year	$49,085	$52,366	-6.27%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	$23,870	$16,953	40.80%
30	Actual return on plan assets	4,859	4,459	8.97%
31	Acquisition	-	-	
32	Employer contribution	4,526	4,997	-9.43%
33	Plan participants' contributions	413	324	27.47%
34	Benefits paid	(2,865)	(2,863)	-0.07%
35	Fair value of plan assets at end of year	$30,803	$23,870	29.04%
36	**Funded Status**	($18,282)	($28,496)	35.84%
37	Unrecognized net actuarial loss	(6,099)	(1,982)	-207.72%
38	Unrecognized prior service cost	(1,233)	-	-100.00%
39	Unrecognized transition obligation	24,500	29,362	-16.56%
40	Prepaid (accrued) benefit cost	($1,114)	($1,116)	0.18%
41	**Components of Net Periodic Benefit Costs**			
42	Service cost	$984	$875	12.46%
43	Interest cost	3,444	3,516	-2.05%
44	Expected return on plan assets	(1,861)	(1,359)	-36.94%
45	Amortization of prior service cost	-	-	
46	Transition amount amortization	1,957	1,957	
47	Net periodic benefit cost	$4,524	$4,989	-9.32%
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount Funded through VEBA	$4,939	$5,321	-7.18%
50	Amount Funded through 401(h)			
51	Amount Funded through Other ________________			
52	TOTAL	$4,939	$5,321	-7.18%
53	Amount that was tax deductible - VEBA	$2,714 1/	$2,859	-5.07%
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other ____________			
56	TOTAL	$2,714	$2,859	-5.07%

1/ Estimated.

Company Name: Montana-Dakota Utilities Co.

Other Post Employment Benefits (OPEBS) Continued

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	1,898	1,915	-0.89%
3	Not Covered by the Plan	13	19	-31.58%
4	Active	1,106	1,132	-2.30%
5	Retired	592	582	1.72%
6	Spouses/Dependants covered by the Plan	200	201	-0.50%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost	NOT APPLICABLE		
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ______			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 16

Year: 1998

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1							
2							
3							
4							
5	PROPRIETARY SCHEDULE						
6							
7							
8							
9							
10							

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 17
Year: 1998

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other 1/	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Martin A. White - President & C.E.O.	$254,808	$139,461	$226,338	$620,607	$206,641	200%
2	Douglas C. Kane - Executive Vice President Chief Administrative & Corporate Development Officer	210,185	63,032	260,894	534,111	298,772	79%
3	Ronald D. Tipton - President & C.E.O. of Montana-Dakota Utilities Co.	223,491	103,500	196,950	523,941	297,853	76%
4	Warren L. Robinson - Vice President, Treasurer & Chief Financial Officer	150,865	57,855	161,567	370,287	196,458	88%
5	Lester H. Loble, II - Secretary & General Counsel	139,694	43,848	126,707	310,249	189,367	64%

1/ See page 20a for details.

EXECUTIVE COMPENSATION

Shown below is information concerning the annual and long-term compensation for services in all capacities to the Company for the calendar years ending December 31, 1998, 1997, and 1996, for those persons who (i) served as the Chief Executive Officer during 1998, and (ii) were the other four most highly compensated executive officers of the Company at December 31, 1998 (the "Named Officers"). Footnotes supplement the information contained in the Tables.

TABLE 1: SUMMARY COMPENSATION TABLE(1)

		Annual compensation			Long-term compensation			
					Awards		Payouts	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Name and principal position	Year	Salary ($)	Bonus(2) ($)	Other annual compensation(3) ($)	Restricted stock awards(4) ($)	Securities underlying Options/SARs(5) (#)	LTIP payouts(6) ($)	All other compensation(7) ($)
Martin A. White	1998	254,808	139,461		54,157	122,760	43,937	5,484
—President & C.E.O.	1997	147,316	54,450		—	—	—	4,875
	1996	135,856	52,350		—	—	—	4,076
Harold J. Mellen, Jr.	1998	176,447	38,367	16,408	109,243	2,250	244,865	12,947
—President & C.E.O.	1997	342,735	186,450	10,581	—	—	—	6,598
(retired 3/31/98)	1996	276,373	189,150		—	—	—	5,886
Douglas C. Kane	1998	210,185	63,032		62,689	55,800	137,605	4,800
—Executive Vice President	1997	201,772	92,250		—	—	—	4,750
Chief Administrative & Corporate Development Officer	1996	192,281	106,500		—	—	—	4,500
Ronald D. Tipton	1998	223,491	103,500		—	49,125	142,827	4,998
—President & C.E.O. of	1997	200,655	92,250		—	—	—	4,948
Montana-Dakota Utilities Co.	1996	190,000	115,363		—	—	—	4,788
Warren L. Robinson	1998	150,865	57,855		43,771	37,950	75,320	4,526
—Vice President, Treasurer	1997	128,843	63,750		—	—	—	3,865
& Chief Financial Officer	1996	111,937	58,200		—	—	—	2,773
Lester H. Loble, II	1998	139,694	43,848	3,963	41,916	27,900	48,737	4,191
—Secretary and	1997	127,473	54,450	3,620	—	—	—	3,824
General Counsel	1996	122,592	47,100		—	—	—	3,688

(1) All share amounts in the table are adjusted to reflect the Company's three-for-two stock split on July 13, 1998.

(2) Granted pursuant to the Executive Incentive Compensation Plan.

(3) Above-market interest on deferred compensation.

(4) The restricted stock awards in the table are valued at fair market value on the date of grant. At December 31, 1998, the Named Officers held the following amounts of restricted stock: Mr. White—2,190 shares ($58,172); Mr. Mellen—4,440 shares ($117,938); Mr. Kane—2,535 shares ($67,336); Mr. Tipton—2,250 shares ($59,766); Mr. Robinson—1,770 ($47,016); and Mr. Loble—1,695 shares ($45,023).

(5) Options granted pursuant to the 1992 KESOP for the 1998-2000 performance cycle except for Mr. Mellen who received options as part of his Director compensation after his retirement as CEO.

(6) Dividend equivalents paid with respect to options granted pursuant to the 1992 KESOP for the 1995-1997 performance cycle.

(7) Totals shown are the Company contributions to the Tax Deferred Compensation Savings Plan, with the following exceptions: Mr. White's total includes insurance premiums of $684; Mr. Mellen's total includes insurance premiums of $462 and excess retirement benefit of $7,835; and Mr. Tipton's total includes insurance premiums of $198.

TABLE 2: OPTION/SAR[1] GRANTS IN LAST FISCAL YEAR[2]

Named Officer (a)	Individual Grants(3) Number of securities underlying options granted (#) (b)	Percent of total options granted to employees in fiscal year(%) (c)	Exercise or base price ($/share) (d)	Expiration date (e)	Grant date value: Grant date present value(4) ($) (f)
Martin A. White	122,760	10.2	21.13	2/10/08	293,396
Harold J. Mellen, Jr.	2,250	.2	23.08	6/3/08	7,673
Douglas C. Kane	55,800	4.6	21.13	2/10/08	133,362
Ronald D. Tipton	49,125	4.1	21.13	2/10/08	117,409
Warren L. Robinson	37,950	3.1	21.13	2/10/08	90,701
Lester H. Loble, II	27,900	2.3	21.13	2/10/08	66,681

(1) "SAR" is an acronym for "stock appreciation right." The Company has no plan or program which uses stock appreciation rights.

(2) Adjusted to reflect the Company's three-for-two stock split on July 13, 1998.

(3) All options except Mr. Mellen's were granted pursuant to the 1992 Key Employee Stock Option Plan. Mr. Mellen's options were granted as part of his Director compensation after his retirement as CEO and vested immediately upon grant. The options granted under the 1992 Key Employee Stock Option Plan become exercisable automatically in nine years on February 10, 2007. Vesting is accelerated upon change in control or upon attainment of certain performance goals, as follows: during the three year performance cycle (1998-2000) performance goals established for the Company by the Compensation Committee are based on return on equity (25%), earnings per share (25%) and total relative shareholder return (50%). Performance goals for Montana-Dakota Utilities Co. and the utility services companies, which are applicable to Mr. Tipton, are based on return on equity (50%) and earnings (50%). From 50% to 100% of the options granted may become exercisable at the end of the three year performance cycle if from 90% to 100% of the goals are met.

Dividend Equivalents granted with the options are described in Table 4.

(4) Present values were calculated using the Black-Scholes option pricing model which has been adjusted to take dividends into account. Use of this model should not be viewed in any way as a forecast of the future performance of the Company's stock. The estimated present value of each stock option granted pursuant to the 1992 Key Employee Stock Option Plan is $2.39 based on the following inputs:

Stock Price (fair market value) at Grant (2/10/98)	$21.13
Exercise Price	$21.13
Expected Option Term	7 Years
Stock Price Volatility	0.1625
Dividend Yield	5.13%

The model assumes: (a) a risk-free interest rate of 4.78 percent on a U.S. Treasury Note with a maturity date of approximately 7 years; (b) Stock Price Volatility is calculated using a three year historical average of stock prices from grant date; (c) Dividend Yield is calculated using the historical dividend rate for three years from the date of grant. The option value was not discounted to reflect any accelerated vesting of the options. Notwithstanding the fact that these options are non-transferable, no discount for lack of marketability was taken.

The option grants to Mr. Mellen were made pursuant to the 1997 Non-Employee Director Long-Term Incentive Plan under assumptions similar to those for the Key Employee Stock Option Plan except that assumptions differing from those utilized with respect to the Key Employee Stock Option Plan were: (a) a Stock Price at grant and Exercise Price of $23.08; (b) a risk free interest rate of 4.87 percent; (c) Stock Price Volatility of 0.2001; and (d) Dividend Yield of 4.94 percent. Based on these inputs, the estimated present value of each stock option granted to Mr. Mellen is $3.41.

TABLE 3: AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END OPTION/SAR VALUES(1)

(a)	(b) Shares acquired on exercise (#)	(c) Value realized ($)	(d) Number of securities underlying unexercised options at fiscal year-end(2) (#)		(e) Value of unexercised, in-the-money options at fiscal year-end ($)	
Name			Exercisable	Unexercisable	Exercisable	Unexercisable
Martin A. White	22,652	319,271	0	122,760	0	667,508
Harold J. Mellen, Jr.	74,610	767,800	2,250(3)	0	7,828	0
Douglas C. Kane	10,000	147,500	46,343	55,800	667,518	303,413
Ronald D. Tipton	49,432	666,304	0	49,125	0	267,117
Warren L. Robinson	17,137	179,309	7,912	37,950	112,581	206,353
Lester H. Loble, II	0	0	14,850	27,900	211,304	151,706

(1) Adjusted to reflect the Company's three-for-two stock split on July 13, 1998.

(2) Vesting is accelerated upon a change in control.

(3) Options were awarded under the 1997 Non-Employee Director Long-Term Incentive Plan on June 3, 1998.

TABLE 4: LONG-TERM INCENTIVE PLAN—AWARDS IN LAST FISCAL YEAR(1)

(a)	(b)	(c)	Estimated future payouts under non-stock price-based plans		
			(d)	(e)	(f)
Named Officer	Number of shares, units or other rights (#)(2)	Performance or other period until maturation or payout	Threshold ($)	Target ($)	Maximum ($)
Martin A. White	122,760	1998-2000	147,312	294,624	441,936
Harold J. Mellen, Jr.	—	—	—	—	—
Douglas C. Kane	55,800	1998-2000	66,960	133,920	200,880
Ronald D. Tipton	49,125	1998-2000	58,950	117,900	176,850
Warren L. Robinson	37,950	1998-2000	45,540	91,080	136,620
Lester H. Loble, II	27,900	1998-2000	33,480	66,960	100,440

(1) Adjusted to reflect the Company's three-for-two stock split on July 13, 1998.

(2) Dividend equivalents were granted pursuant to the 1992 Key Employee Stock Option Plan based on the number of options granted to each Named Officer (see Table 2). Dividend equivalents entitle the recipient to the cash amount equal to any dividend declared by the Board of Directors on the common stock of the Company. The table assumes the current level of dividends. Dividend equivalents may be earned from 0% to 150% at the end of the three year performance cycle (1998-2000) depending upon (1) the level of achievement of performance goals established for the Company and Montana-Dakota Utilities Co. and the utility services companies by the Compensation Committee and (2) individual

performance. Vesting is accelerated upon a change in control. See Table 2 for a description of the goals. Dividend equivalents that are not earned are forfeited.

TABLE 5: PENSION PLAN TABLE

Remuneration	Years of Service 15	20	25	30	35
$125,000	$ 79,572	$ 88,215	$ 96,859	$105,503	$114,147
150,000	95,689	106,145	116,602	127,058	137,514
175,000	108,545	119,726	130,908	142,090	153,271
200,000	121,145	132,326	143,508	154,690	165,871
225,000	132,125	143,306	154,488	165,670	176,851
250,000	143,045	154,226	165,408	176,590	187,771
300,000	179,285	190,466	201,648	212,830	224,011
350,000	226,865	238,046	249,228	260,410	271,591
400,000	267,845	279,026	290,208	301,390	312,571
450,000	307,745	318,926	330,108	341,290	352,471
500,000	347,945	359,126	370,308	381,490	392,671

The Table covers the amounts payable under the Salaried Pension Plan and non-qualified Supplemental Income Security Plan (SISP). Pension benefits are determined by the step-rate formula which places emphasis on the highest consecutive 60 months of earnings within the final 10 years of service. Benefits for single participants under the Salaried Pension Plan are paid as straight life amounts and benefits for married participants are paid as actuarially reduced pensions with a survivorship benefit for spouses, unless participants choose otherwise. The Salaried Pension Plan also permits preretirement survivorship benefits upon satisfaction of certain conditions. Additionally, certain reductions are made for employees electing early retirement.

The Internal Revenue Code places maximum limitations on the amount of benefits that may be paid under the Salaried Pension Plan. The Company has adopted a non-qualified SISP for senior management personnel. In 1998, 70 senior management personnel participated in the SISP, including the Named Officers. Both plans cover salary shown in column (c) of the Summary Compensation Table and exclude bonuses and other forms of compensation.

Upon retirement and attainment of age 65, participants in the SISP may elect a retirement benefit or a survivors' benefit with the benefits payable monthly for a period of 15 years.

As of December 31, 1998, the Named Officers were credited with the following years of service under the plans: Mr. White: Pension, 7, SISP, 7; Mr. Mellen: Pension, 12, SISP, 12; Mr. Kane: Pension, 27, SISP, 17; Mr. Tipton: Pension, 15, SISP, 15; Mr. Robinson: Pension 10, SISP 10; and Mr. Loble: Pension, 11, SISP, 11. The maximum years of service for benefits under the Pension Plan is 35 and under the SISP vesting begins at 3 years and is complete after 10 years. Benefit amounts under both plans are not subject to reduction for offset amounts.

Change-of-Control Arrangements

The Company entered into Change of Control Employment Agreements with the Named Officers (except Mr. Mellen) in November 1998, which would become effective for a three-year period (with automatic annual extension if the Company does not provide nonrenewal notice at least 60 days prior to the end of each 12-month period) only upon a change of control of the Company. If a change of control occurs, the agreements provide for a three-year employment period from the date they become effective, with base salary not less than the highest amount paid within the preceding twelve months, an annual bonus not less than the highest bonus paid within the preceding three years, and participation in the Company's incentive, savings, retirement and welfare benefit plans.

The agreements also provide that specified payments and benefits would be paid in the event of involuntary termination of employment, other than for cause or disability, at any time when the agreements are in effect. In such event, each of the Named Officers (except Mr. Mellen) would receive payment of an amount equal to three times his annual base pay plus three times his highest annual bonus (as defined therein). In addition, under these agreements, each of the officers would receive (i) an immediate pro-rated cash-out of his bonus for the year of termination based on the highest annual bonus and (ii) an amount equal to the excess of (a) the actuarial equivalent of the benefit under Company qualified and nonqualified retirement plans that the executive would receive if he continued employment with the Company for an additional three years over (b) the actual benefit paid or payable under these plans. All benefits of each executive officer under the Company's welfare benefit plans would continue for at least three years. These arrangements also provide for certain gross-up payments to compensate these executive officers for any excise taxes incurred in connection with these benefits and reimbursement for certain outplacement services.

For these purposes, "cause" means the Named Officer's willful and continued failure to substantially perform his duties or willfully engaging in illegal conduct or misconduct materially injurious to the Company, and "good reason" includes the Company's termination of the Named Officer without cause, the assignment to the Named Officer of duties inconsistent with his prior status and position, certain reductions in compensation or benefits, and relocation or increased travel obligations.

A "change of control" is defined as (i) the acquisition by a party or certain related parties of 20% or more of the Company's voting securities; (ii) a turnover in a majority of the Board of Directors without the approval of a majority of the members of the Board as of November 1998; (iii) a merger or similar transaction after which the Company's shareholders hold 60% or less of the voting securities of the surviving entity; or (iv) the stockholders' approval of the liquidation or dissolution of the Company.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

Introduction

The Compensation Committee of the Board of Directors is responsible for determining the compensation of the Company's executive officers. Composed entirely of non-employee Directors, the Committee meets several times each year to review and determine compensation for the executive officers, including the Chief Executive Officer.

Executive Compensation

The Committee firmly believes that appropriate compensation levels succeed in both attracting and motivating high quality employees. To implement this philosophy, the Committee analyzes trends in compensation among comparable companies participating in the oil and gas industry, segments of the energy and mining industries, the peer group of companies used in the graph following this report, and similar companies from general industry. The Committee then sets compensation levels that it believes are competitive within the industry and structured in a manner that rewards successful performance on the job. There are three components of total executive compensation: base salary, annual incentive compensation, and long-term incentive compensation.

In setting base salaries, the Committee does not use a particular formula. In addition to the data referenced above, other factors the Committee uses in its analysis include the executive's current salary in comparison to the competitive industry standard as well as individual performance. Using this system, the Committee granted to Mr. White, the President and Chief Executive Officer, a 44% increase in base salary. This increase took into account Mr. White's promotion from Senior Vice President — Corporate

Development to President and Chief Executive Officer, his personal role in achieving 1998 corporate performance, his rapid and capable assumption of his new duties, and the successful acquisitions made during the year. During 1998, only approximately 39.7% of Mr. White's compensation was base pay. The remainder was performance-based. This reflects the Committee's belief in the importance of having substantial at risk compensation to provide a direct and strong link between performance and executive pay. The other Named Officers, excluding Mr. Mellen, received base salary increases averaging 6.4% in 1998.

In keeping with the Committee's belief that compensation should be directly linked to successful performance, the Company employs both annual and long-term incentive compensation plans. The annual incentive compensation is determined under the Executive Incentive Compensation Plan. The Committee makes awards based upon the level of corporate earnings, cost efficiency, and individual performance. Mr. White received a total of $139,461 (or 116.7% of the targeted amount) in annual incentive compensation for 1998; the other Named Officers, excluding Mr. Mellen, received an average of $67,059, or 119% of the targeted amount, based upon achievement of corporate earnings and individual performance near the maximum level.

Long-term incentive compensation serves to encourage successful strategic management and is determined through three different vehicles: the 1992 Key Employee Stock Option Plan, the Restricted Stock Bonus Plan, and the 1997 Executive Long-Term Incentive Plan. Options with a three-year performance cycle (1998-2000) and related dividend equivalents were granted in 1998 under the 1992 Key Employee Stock Option Plan to Mr. White, the other Named Officers and certain other executives. Since options granted in 1995 vested in full in 1997 based upon achievement of performance goals at the maximum level for the 1995-1997 performance cycle, the Committee granted new stock options and dividend equivalents in 1998 to continue to motivate executives to achieve long-term corporate performance goals and to encourage ownership by them of Company common stock. The options become exercisable automatically in nine years, but vesting may be accelerated if certain performance goals are achieved. The number of options and dividend equivalents granted was determined based upon a percent of the salary of each executive.

Restricted stock awards were also made in 1998 to Mr. White and the other Named Officers to reward them for successful acquisitions completed by the Company during 1998. The restricted stock serves to motivate long-term performance and to align the interests of the executives with those of stockholders.

In 1994, the Board of Directors adopted Stock Ownership Guidelines under which executives are required to own Company Common Stock valued from one to four times their annual salary.

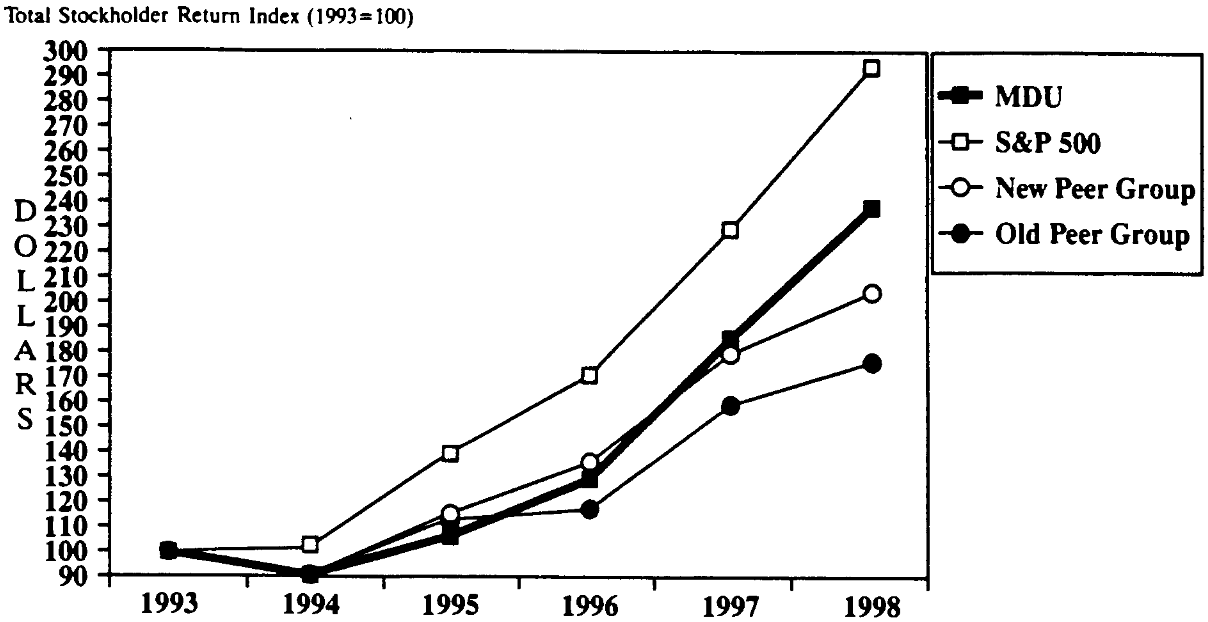
The 1998 compensation paid to the Company's executive officers qualified as fully deductible under federal tax laws. The Committee continues to review the impact of federal tax laws on executive compensation, including Section 162(m) of the Internal Revenue Code, but has not formulated any policy with regard thereto.

San W. Orr, Jr., Chairman

Harry J. Pearce, Member

Homer A. Scott, Jr., Member

MDU RESOURCES GROUP, INC.
COMPARISON OF FIVE YEAR TOTAL STOCKHOLDER RETURN (1)



	1993	1994	1995	1996	1997	1998
MDU	100	91	106	129	185	238
S&P 500	100	101	139	171	229	294
New Peer Group	100	91	115	136	179	204
Old Peer Group	100	91	113	117	159	176

(1) All data is indexed to December 31, 1993, for the Company, the S&P 500, and the peer groups. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group is weighted according to the issuer's stock market capitalization at the beginning of the period. New Peer Group issuers are Black Hills Corporation, Coastal Corporation, Equitable Resources, Inc., LG&E Energy Corp., Minnesota Power & Light Company, The Montana Power Company, Northwestern Corporation, ONEOK, Inc., Otter Tail Power Company, Questar Corporation, and UGI Corporation. Old Peer Group issuers are Black Hills Corporation, CILCORP, Inc., Equitable Resources, Inc., Florida Progress Corporation, Minnesota Power & Light Company, The Montana Power Company, ONEOK, Inc., Questar Corporation, South Jersey Industries, Inc., Teco Energy, Inc., UGI Corporation, and Utilicorp United Inc. The peer group was changed to include issuers that better reflect the Company's mix of regulated and unregulated businesses.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 18
Page 1 of 3
Year: 1998

BALANCE SHEET

	Account Number & Title		Last Year	This Year	% Change
1	**Assets and Other Debits**				
2	Utility Plant				
3	101	Gas Plant in Service	$151,377,162	$156,229,467	3.21%
4	101.1	Property Under Capital Leases			
5	102	Gas Plant Purchased or Sold			
6	104	Gas Plant Leased to Others	34,073	29,961	-12.07%
7	105	Gas Plant Held for Future Use			
8	105.1	Production Properties Held for Future Use			
9	106	Completed Constr. Not Classified - Gas			
10	107	Construction Work in Progress - Gas	686,643	522,991	-23.83%
11	108	(Less) Accumulated Depreciation	(85,178,131)	(90,603,621)	6.37%
12	111	(Less) Accumulated Amortization & Depletion	(296,563)	(356,552)	20.23%
13	114	Gas Plant Acquisition Adjustments			
14	115	(Less) Accum. Amort. Gas Plant Acq. Adj.			
15	116	Other Gas Plant Adjustments			
16	117	Gas Stored Underground - Noncurrent	2,847,532	3,386,816	18.94%
17	118	Other Utility Plant	577,312,446	585,634,157	1.44%
18	119	Accum. Depr. and Amort. - Other Utl. Plant	(289,278,461)	(302,164,119)	4.45%
19	**TOTAL Utility Plant**		$357,504,701	$352,679,100	-1.35%
20	**Other Property & Investments**				
21	121	Nonutility Property	$124,347	$162,463	30.65%
22	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(4,196)	(6,418)	52.96%
23	123	Investments in Associated Companies			
24	123.1	Investments in Subsidiary Companies	261,413,923	424,583,132	62.42%
25	124	Other Investments	13,003,762	28,287,140	117.53%
26	125	Sinking Funds			
27	**TOTAL Other Property & Investments**		$274,537,836	$453,026,317	65.01%
28	**Current & Accrued Assets**				
29	131	Cash	$6,039,234	$6,460,876	6.98%
30	32-134	Special Deposits	1,100	1,100	
31	135	Working Funds	15,005	14,705	-2.00%
32	136	Temporary Cash Investments	100,000		-100.00%
33	141	Notes Receivable			
34	142	Customer Accounts Receivable	23,294,761	19,267,843	-17.29%
35	143	Other Accounts Receivable	1,883,952	2,223,002	18.00%
36	144	(Less) Accum. Provision for Uncollectible Accts.	(154,989)	(142,462)	-8.08%
37	145	Notes Receivable - Associated Companies			
38	146	Accounts Receivable - Associated Companies	4,143,546	7,359,210	77.61%
39	151	Fuel Stock	2,056,269	2,011,153	-2.19%
40	152	Fuel Stock Expenses Undistributed			
41	153	Residuals and Extracted Products			
42	154	Plant Materials and Operating Supplies	6,176,509	6,079,423	-1.57%
43	155	Merchandise	387,543	540,426	39.45%
44	156	Other Material & Supplies			
45	163	Stores Expense Undistributed			
46	164.1	Gas Stored Underground - Current	9,388,410	9,106,722	-3.00%
47	165	Prepayments	6,439,544	6,982,358	8.43%
48	166	Advances for Gas Explor., Devl. & Production			
49	171	Interest & Dividends Receivable	8,739	5,846	-33.10%
50	172	Rents Receivable			
51	173	Accrued Utility Revenues	18,160,495	21,172,408	16.58%
52	174	Miscellaneous Current & Accrued Assets	97,393	3,087	-96.83%
53	**TOTAL Current & Accrued Assets**		$78,037,511	$81,085,697	3.91%

BALANCE SHEET

Year: 1998

		Account Number & Title	Last Year	This Year	% Change
1		**Assets and Other Debits (cont.)**			
2					
3	**Deferred Debits**				
4					
5	181	Unamortized Debt Expense	$1,693,092	$1,662,010	-1.84%
6	182.1	Extraordinary Property Losses			
7	182.2	Unrecovered Plant & Regulatory Study Costs			
	182.3	Other Regulatory Assets	6,270,750	5,568,013	-11.21%
	183	Prelim. Electric Survey & Investigation Chrg.	933,882	240,807	-74.21%
8	183.1	Prelim. Nat. Gas Survey & Investigation Chrg.			
9	183.2	Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
10	184	Clearing Accounts	(49,222)	(11,705)	-76.22%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	4,235,636	5,685,066	34.22%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	11,465,899	10,995,223	-4.11%
16	190	Accumulated Deferred Income Taxes	19,661,675	21,020,788	6.91%
17	191	Unrecovered Purchased Gas Costs	(21,721,470)	(274,040)	-98.74%
18	192.1	Unrecovered Incremental Gas Costs			
19	192.2	Unrecovered Incremental Surcharges			
20		**TOTAL Deferred Debits**	$22,490,242	$44,886,162	99.58%
21					
22	**TOTAL ASSETS & OTHER DEBITS**		$732,570,290	$931,677,276	27.18%

		Account Number & Title	Last Year	This Year	% Change
23		**Liabilities and Other Credits**			
24					
25	**Proprietary Capital**				
26					
27	201	Common Stock Issued	$97,047,296	$177,398,927	82.80%
28	202	Common Stock Subscribed			
29	204	Preferred Stock Issued	16,800,000	16,700,000	-0.60%
30	205	Preferred Stock Subscribed			
31	207	Premium on Capital Stock	78,867,179	174,158,583	120.83%
32	211	Miscellaneous Paid-In Capital			
33	213	(Less) Discount on Capital Stock			
34	214	(Less) Capital Stock Expense	(2,340,953)	(2,672,372)	14.16%
35	216	Appropriated Retained Earnings	33,962,961	36,965,806	8.84%
36	216.1	Unappropriated Retained Earnings	178,759,219	168,616,836	-5.67%
37	217	(Less) Reacquired Capital Stock			
38		**TOTAL Proprietary Capital**	$403,095,702	$571,167,780	41.70%
39					
40	**Long Term Debt**				
41					
42	221	Bonds	$135,850,000	$130,850,000	-3.68%
43	222	(Less) Reacquired Bonds			
44	223	Advances from Associated Companies			
45	224	Other Long Term Debt	21,700,000	43,400,000	100.00%
46	225	Unamortized Premium on Long Term Debt			
47	226	(Less) Unamort. Discount on Long Term Debt-Dr.	(84,637)	(58,897)	-30.41%
48		**TOTAL Long Term Debt**	$157,465,363	$174,191,103	10.62%

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTE 1

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The consolidated financial statements of MDU Resources Group, Inc. (company) include the accounts of two regulated businesses -- retail and wholesale sales of electricity and retail sales and/or transportation of natural gas and propane, and natural gas transmission and storage -- and two nonregulated businesses -- construction materials and mining operations, and oil and natural gas production. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating stations.

The company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the company's nonregulated businesses.

The company's regulated businesses account for certain income and expense items under the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (SFAS No. 71). SFAS No. 71 allows these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items are generally based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 3 for more information regarding the nature and amounts of these regulatory deferrals.

In accordance with the provisions of SFAS No. 71, intercompany coal sales, which are made at prices approximately the same as those charged to others, and the related utility fuel purchases are not eliminated. All other significant intercompany balances and transactions have been eliminated.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost when first placed in service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost and cost of removal, less salvage, is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for oil and natural gas production properties as described below, the resulting gains or losses are recognized as a component of income. The company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amounts of AFUDC and interest capitalized were not material in 1998, 1997 and 1996. Property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for oil and natural gas production properties as described below.

Oil and natural gas

The company uses the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on the units of production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter.

Due to low oil and natural gas prices, the company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at June 30, 1998 and December 31, 1998. Accordingly, the company was required to write down its oil and natural gas producing properties. These noncash write-downs amounted to $33.1 million ($20.0 million after tax) and $32.9 million ($19.9 million after tax) for the quarters ended June 30, 1998 and December 31, 1998, respectively.

Natural gas in underground storage and available under repurchase commitment
Natural gas in underground storage is carried at cost using the last-in, first-out (LIFO) method. The portion of the cost of natural gas in underground storage expected to be used within one year is included in inventories.

Natural gas available under a repurchase commitment with Frontier Gas Storage Company (Frontier) is carried at Frontier's cost of purchased natural gas, less an allowance to reflect changed market conditions, and is reflected on the company's Consolidated Balance Sheets in "Deferred charges and other assets." See Note 15 for discussion on the write-down which occurred in 1996 of the natural gas available under the repurchase commitment with Frontier.

Inventories
Inventories, other than natural gas in underground storage, consist primarily of materials and supplies and inventories held for resale. These inventories are stated at the lower of average cost or market.

Revenue recognition
The company recognizes utility revenue each month based on the services provided to all utility customers during the month. For its construction businesses, the company recognizes construction contract revenue on the percentage of completion method. The company generally recognizes all other revenues when services are rendered or goods are delivered.

Natural gas costs recoverable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the company is deferring natural gas commodity, transportation and storage costs which are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within 24 months from the time such costs are paid.

Income taxes

The company provides deferred federal and state income taxes on all temporary differences. Excess deferred income tax balances associated with Montana-Dakota's and Williston Basin's rate-regulated activities resulting from the company's adoption of SFAS No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in "Other liabilities" in the company's Consolidated Balance Sheets. These regulatory liabilities are expected to be reflected as a reduction in future rates charged customers in accordance with applicable regulatory procedures.

The company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods which conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Earnings per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options. Common stock outstanding includes issued shares less shares held in treasury. Earnings per share have been restated to reflect the three-for-two common stock split effected in July 1998 as discussed in Note 8.

Comprehensive income

On January 1, 1998, the company adopted Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income" (SFAS No. 130). SFAS No. 130 provides authoritative guidance on the reporting and display of comprehensive income and its components. For the years ended December 31, 1998, 1997 and 1996, comprehensive income equaled net income as reported.

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires the company 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. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, environmental and other loss contingencies, accumulated provision for revenues subject to refund, unbilled revenues and actuarially determined benefit costs. As better information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31, (In thousands)	1998	1997	1996
Interest, net of amount capitalized	$26,394	$25,626	$25,449
Income taxes	$34,498	$18,171	$28,163

The company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Reclassifications

Certain reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or common stockholders' equity as previously reported.

New accounting standard

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset the related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

SFAS No. 133 is effective for fiscal years beginning after June 15, 1999. SFAS No. 133 must be applied to derivative instruments and certain derivative instruments embedded in hybrid contracts that were issued, acquired, or substantively modified after December 31, 1997. The company will adopt SFAS No. 133 on January 1, 2000, and has not yet quantified the impacts of adopting SFAS No. 133 on the company's financial position or results of operations.

NOTE 2

NATURAL GAS IN UNDERGROUND STORAGE

Natural gas in underground storage included in natural gas transmission and natural gas distribution property, plant and equipment amounted to $43.7 million at December 31, 1998, and $43.1 million at December 31, 1997. In addition, $11.5 million and $11.4 million at December 31, 1998 and 1997, respectively, of natural gas in underground storage is included in inventories.

NOTE 3

REGULATORY ASSETS AND LIABILITIES

The following table summarizes the individual components of unamortized regulatory assets and liabilities included in the accompanying Consolidated Balance Sheets as of December 31:

(In thousands)	1998	1997
Regulatory assets:		
Long-term debt refinancing costs	$ 10,995	$ 11,466
Postretirement benefit costs	2,036	2,940
Plant costs	3,003	3,173
Other	11,647	10,899
Total regulatory assets	27,681	28,478
Regulatory liabilities:		
Reserves for regulatory matters	39,981	39,193

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NOTES TO FINANCIAL STATEMENTS (continued)

Taxes refundable to customers	14,129	13,933
Plant decommissioning costs	6,413	5,843
Natural gas costs refundable through rate adjustments	274	21,721
Other	1,351	1,393
Total regulatory liabilities	62,148	82,083
Net regulatory position	$ (34,467)	$ (53,605)

As of December 31, 1998, substantially all of the company's regulatory assets are being reflected in rates charged to customers and are being recovered over the next 1 to 18 years.

If, for any reason, the company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 4

FINANCIAL INSTRUMENTS

Derivatives

Williston Basin Interstate Pipeline Company and Fidelity Oil Group have entered into certain price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas. These swap and collar agreements are not held for trading purposes. The swap and collar agreements call for Williston Basin and Fidelity to receive monthly payments from or make payments to counterparties based upon the difference between a fixed and a variable price as specified by the agreements. The variable price is either an oil price quoted on the New York Mercantile Exchange (NYMEX) or a quoted natural gas price on the NYMEX or Colorado Interstate Gas Index. The company believes that there is a high degree of correlation because the timing of purchases and production and the swap and collar agreements are closely matched, and hedge prices are established in the areas of operations. Amounts payable or receivable on the swap and collar agreements are matched and reported in operating revenues on the Consolidated Statements of Income as a component of the related commodity transaction at the time of settlement with the counterparty. The amounts payable or receivable are generally offset by corresponding increases and decreases in the value of the underlying commodity transactions.

Innovative Gas Services, Incorporated participates in the natural gas futures market to hedge a portion of the price risk associated with natural gas purchase and sale commitments. These futures are not held for trading purposes. Gains or losses on the futures contracts are deferred until the transaction occurs, at which point they are reported in "Purchased natural gas sold" on the Consolidated Statements of Income. The gains or losses on the futures contracts are generally offset by corresponding increases and decreases in the value of the underlying commodity transactions.

Williston Basin and Knife River Corporation entered into interest rate swap agreements to manage a portion of their interest rate exposure on the natural gas repurchase commitment and long-term debt, respectively. These interest rate swap agreements, which expired in August 1997 and August 1998, respectively, were not held for trading purposes. The interest rate swap agreements called for Williston Basin and Knife River to receive quarterly payments from or make payments to counterparties based upon the difference between fixed and variable rates as specified by the interest rate swap agreements. The variable prices were based on the three-month floating London Interbank Offered Rate. Settlement amounts payable or receivable under these interest rate swap agreements were recorded in "Interest expense" for Knife River and "Costs on natural gas repurchase commitment" for Williston Basin on the Consolidated Statements of Income in the accounting period they were incurred. The amounts payable or receivable were generally offset by interest on the related debt instruments.

The company's policy prohibits the use of derivative instruments for trading purposes and the company has procedures in place to monitor compliance with its policies. The company is exposed to credit-related losses in relation to financial instruments in the event of nonperformance by counterparties, but does not expect any counterparties to fail to meet their obligations given their existing credit ratings.

The following table summarizes the company's hedging activity:

Years ended December 31,	1998	1997	1996
(Notional amounts in thousands)			
Oil swap agreements:*			
Range of fixed prices per barrel	$20.92	$19.77-$21.36	$18.74-$19.07
Notional amount (in barrels)	219	730	635
Natural gas swap/collar agreements:*			
Range of fixed prices per MMBtu	$1.54-$2.67	$1.30-$2.395	$1.40-$2.05
Notional amount (in MMBtu's)	6,082	8,039	5,331
Natural gas futures contracts:*			
Range of fixed prices per MMBtu	$1.96-$2.50	---	---
Notional amount (in MMBtu's)	650	---	---
Natural gas collar agreement:**			
Range of fixed prices per MMBtu	---	---	$1.22-$1.52
Notional amount (in MMBtu's)	---	---	910
Interest rate swap agreements:**			
Range of fixed interest rates	5.50%-6.50%	5.50%-6.50%	5.50%-6.50%
Notional amount (in dollars)	$10,000	$30,000	$30,000

* Receive fixed -- pay variable
** Receive variable -- pay fixed

At December 31, 1998, the company has natural gas collar agreements outstanding for 2.9 million MMBtu's of natural gas which call for the company, in 1999, to receive monthly payments from counterparties when the settlement price is below the floor price in the collar agreement or make monthly payments to counterparties when the settlement price is above the ceiling price in the collar agreement. The weighted average floor price and ceiling price is $2.10 and $2.51, respectively.

The fair value of these derivative financial instruments reflects the estimated amounts that the company would receive or pay to terminate the contracts at the reporting date, thereby taking into account the current favorable or unfavorable position on open contracts. The favorable or unfavorable position is currently not recorded on the company's financial statements. Favorable and unfavorable positions related to commodity hedge agreements are expected to be generally offset by corresponding increases and decreases in the value of the underlying commodity transactions. The company's net favorable position on all hedge agreements outstanding at December 31, 1998, was $597,000.

In the event a hedge agreement does not qualify for hedge accounting or when the underlying commodity transaction or related debt instrument matures, is sold, is extinguished, or is terminated, the current favorable or unfavorable position on the open contract would be included in results of operations. The company's policy requires approval to terminate a hedge agreement prior to its original maturity. In the event a hedge agreement is terminated, the realized gain or loss at the time of termination would be deferred until the underlying commodity transaction or related debt instrument is sold or matures and is expected to generally offset the corresponding increases or decreases in the value of the underlying commodity transaction or interest on the related debt instrument.

Fair value of other financial instruments

The estimated fair value of the company's long-term debt and preferred stock subject to mandatory redemption are based on quoted market prices of the same or similar issues. The estimated fair values of the company's long-term debt and preferred stock subject to mandatory redemption at December 31 are as follows:

	1998		1997	
(In thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 416,456	$ 435,078	$ 306,363	$ 319,367
Preferred stock subject to mandatory redemption	$ 1,700	$ 1,592	$ 1,800	$ 1,584

The fair value of other financial instruments for which estimated fair values have not been presented is not materially different than the related carrying amount.

NOTE 5

SHORT-TERM BORROWINGS

The company and its subsidiaries had unsecured short-term lines of credit from a number of banks totaling $60 million at December 31, 1998. These line of credit agreements provide for bank borrowings against the lines and/or support for commercial paper issues. The agreements provide for commitment fees at varying rates. Commercial paper amounts outstanding supported by the lines of credit were $15 million at December 31, 1998, and $3.3 million at December 31, 1997. The weighted average interest rate for borrowings outstanding at December 31, 1998 and 1997, was 5.45 percent and 8.50 percent, respectively. The unused portions of the lines of credit are subject to withdrawal based on the occurrence of certain events.

NOTE 6

LONG-TERM DEBT AND INDENTURE PROVISIONS

Long-term debt outstanding at December 31 is as follows:

NOTES TO FINANCIAL STATEMENTS (continued)

(In thousands)	1998	1997
First mortgage bonds and notes:		
9 1/8% Series, paid in 1998	$ ---	$ 20,000
Pollution Control Refunding Revenue Bonds, Series 1992 --		
Mercer County, North Dakota, 6.65%, due June 1, 2022	15,000	15,000
Morton County, North Dakota, 6.65%, due June 1, 2022	2,600	2,600
Richland County, Montana, 6.65%, due June 1, 2022	3,250	3,250
Secured Medium-Term Notes, Series A --		
6.52%, due October 1, 2004	15,000	15,000
8.25%, due April 1, 2007	30,000	30,000
5.83%, due October 1, 2008	15,000	---
6.71%, due October 1, 2009	15,000	15,000
8.60%, due April 1, 2012	35,000	35,000
Total first mortgage bonds and notes	130,850	135,850
Pollution control note obligation, 6.20%, due March 1, 2004	3,400	3,700
Senior notes:		
8.70%, paid in 1998	---	6,500
8.43%, due December 31, 2000	9,000	12,000
7.35%, due July 31, 2002	4,000	5,000
7.51%, due October 9, 2003	3,000	3,000
6.86%, due October 30, 2004	12,500	12,500
6.43%, due October 30, 2005	10,000	---
7.45%, due May 31, 2006	20,000	20,000
6.68%, due October 30, 2006	15,000	---
7.60%, due November 3, 2008	15,000	15,000
7.10%, due October 30, 2009	12,500	12,500
6.73%, due October 30, 2010	10,000	---
7.28%, due October 30, 2012	10,000	10,000
6.87%, due October 30, 2013	5,000	---
7.05%, due October 30, 2018	15,000	---
Commercial paper at a weighted average rate of 6.49%, supported by a revolving credit agreement due on November 29, 2001	82,921	---
Revolving lines of credit at a weighted average rate of 6.96%, due on dates ranging from January 5, 2001 through December 31, 2002	45,200	64,000
Term credit agreements at a weighted average rate of 7.84%, due on dates ranging from January 28, 2000 through November 25, 2012	13,211	6,398
Other	(126)	(85)
Total long-term debt	416,456	306,363
Less current maturities	3,192	7,802
Net long-term debt	$ 413,264	$ 298,561

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NOTES TO FINANCIAL STATEMENTS (continued)

During 1998, Centennial Energy Holdings, Inc., a direct subsidiary of the company, entered into a revolving credit agreement with various banks on behalf of its subsidiaries that allows for borrowings of up to $200 million. This facility supports the Centennial commercial paper program. Under the Centennial commercial paper program, $82.9 million was outstanding at December 31, 1998. The commercial paper borrowings are classified as long term as the company intends to refinance these borrowings on a long term basis through continued commercial paper borrowings supported by the revolving credit agreement.

Under the revolving lines of credit, the company and a subsidiary have $50 million available, $45.2 million of which was outstanding at December 31, 1998. The amounts of scheduled long-term debt maturities for the five years following December 31, 1998 aggregate $3.2 million in 1999; $12.4 million in 2000; $100.3 million in 2001; $49.4 million in 2002 and $6.4 million in 2003. Substantially all of the company's electric and natural gas distribution properties, with certain exceptions, are subject to the lien of its Indenture of Mortgage. Under the terms and conditions of such Indenture, the company could have issued approximately $273 million of additional first mortgage bonds at December 31, 1998. Certain of the company's other debt instruments contain restrictive covenants all of which the company is in compliance with at December 31, 1998.

NOTE 7

PREFERRED STOCKS

Preferred stocks at December 31 are as follows:

(Dollars in thousands)	1998	1997
Authorized:		
Preferred --		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A --		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference --		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series -- 17,000 and 18,000 shares in 1998 and 1997, respectively	$ 1,700	$ 1,800
Other preferred stock --		
4.50% Series -- 100,000 shares	10,000	10,000
4.70% Series -- 50,000 shares	5,000	5,000
	15,000	15,000
Total preferred stocks	16,700	16,800
Less current maturities and sinking fund requirements	100	100
Net preferred stocks	$ 16,600	$ 16,700

The preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the company with certain limitations on 30 days notice on any quarterly dividend date.

The company is obligated to make annual sinking fund contributions to retire the 5.10% Series preferred stock. The redemption prices and sinking fund requirements, where applicable, are summarized below:

Series	Redemption Price (a)	Sinking Fund Shares	Sinking Fund Price (a)
Preferred stocks:			
4.50%	$105 (b)	---	---
4.70%	$102 (b)	---	---
5.10%	$102	1,000 (c)	$100

(a) Plus accrued dividends.
(b) These series are redeemable at the sole discretion of the company.
(c) Annually on December 1, if tendered.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The aggregate annual sinking fund amount applicable to preferred stock subject to mandatory redemption for each of the five years following December 31, 1998, is $100,000.

NOTE 8
COMMON STOCK
On May 14, 1998, the company's Board of Directors approved a three-for-two common stock split effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on July 13, 1998, to common stockholders of record on July 3, 1998. Common stock information appearing in the accompanying Consolidated Statements of Income and Notes to Consolidated Financial Statements has been restated to give retroactive effect to the stock split.

The company's Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP) provides participants in the DRIP the opportunity to invest all or a portion of their cash dividends in shares of the company's common stock and/or to make optional cash payments of up to $5,000 per month for the same purpose. Holders of all classes of the company's capital stock, legal residents in any of the 50 states, and beneficial owners, whose shares are held by brokers or other nominees, through participation by their brokers or nominees are eligible to participate in the DRIP. The company's Tax Deferred Compensation Savings Plans (K-Plans) pursuant to Section 401(k) of the Internal Revenue Code are funded with the company's common stock. From January 1, 1989, through September 30, 1998, the DRIP and K-Plans have been funded primarily by the purchase of shares of common stock on the open market, except for a portion of 1997 where shares of authorized but unissued common stock were used to fund the DRIP and K-Plans. Beginning October 1, 1998, shares of authorized but unissued common stock were used to fund the DRIP, while the K-Plans continued to be funded by the purchase of shares of common stock on the open market. At December 31, 1998, there were 8.2 million shares of common stock reserved for issuance under the DRIP and K-Plans.

On November 12, 1998, the company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for one one-thousandth of a share of Series B

Preference Stock of the company, without par value, at an exercise price of $125 per one one-thousandth, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.01 per right, at the company's option at any time until any acquiring person has acquired 15 percent or more of the company's common stock.

NOTE 9

INCOME TAXES

Income tax expense is summarized as follows:

Years ended December 31,	1998	1997	1996
(In thousands)			
Current:			
Federal	$ 28,256	$ 15,427	$ 12,617
State	5,880	2,362	3,272
Foreign	605	60	60
	34,741	17,849	15,949
Deferred:			
Investment tax credit	(975)	(1,150)	(1,099)
Income taxes --			
Federal	(14,214)	11,844	1,139
State	(2,067)	2,200	120
Foreign	---	---	(22)
	(17,256)	12,894	138
Total income tax expense	$ 17,485	$ 30,743	$ 16,087

Components of deferred tax assets and deferred tax liabilities recognized in the company's Consolidated Balance Sheets at December 31 are as follows:

(In thousands)	1998	1997
Deferred tax assets:		
Reserves for regulatory matters	$ 35,703	$ 32,789
Natural gas available under repurchase commitment	2,268	4,821
Accrued pension costs	9,274	8,445
Deferred investment tax credits	2,336	2,714
Accrued land reclamation	2,907	3,184
Other	13,266	12,851
Total deferred tax assets	65,754	64,804
Deferred tax liabilities:		
Depreciation and basis differences		

on property, plant and equipment	192,166	123,629
Basis differences on oil and natural gas producing properties	9,604	30,726
Long-term debt refinancing costs	4,491	4,672
Other	15,669	8,168
Total deferred tax liabilities	221,930	167,195
Net deferred income tax liability	$(156,176)	$(102,391)

The following table reconciles the change in the net deferred income tax liability from December 31, 1997, to December 31, 1998, to the deferred income tax expense included in the Consolidated Statements of Income:

(In thousands)	1998
Net change in deferred income tax liability from the preceding table	$ 53,785
Change in tax effects of income tax-related regulatory assets and liabilities	323
Deferred taxes associated with acquisitions	(70,389)
Deferred income tax expense for the period	$ (16,281)

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference are as follows:

Years ended December 31,	1998		1997		1996	
	Amount	%	Amount	%	Amount	%
(Dollars in thousands)						
Computed tax at federal statutory rate	$ 18,057	35.0	$ 29,876	35.0	$ 21,545	35.0
Increases (reductions) resulting from:						
Depletion allowance	(1,571)	(3.0)	(828)	(1.0)	(1,070)	(1.7)
State income taxes -- net of federal income tax benefit	2,312	4.5	3,473	4.1	2,770	4.5
Investment tax credit amortization	(975)	(1.9)	(1,150)	(1.4)	(1,099)	(1.8)
Tax reserve adjustment	---	---	---	---	(6,600)	(10.7)
Other items	(338)	(.7)	(628)	(.7)	541	.8
Total income tax expense	$ 17,485	33.9	$30,743	36.0	$ 16,087	26.1

In 1996, the company reached a settlement with the Internal Revenue Service concerning notices of deficiency issued in connection with disputed items for the 1983 through 1988 tax years and, in 1997, reached a similar settlement for the tax years 1989 through 1991. In 1996, the company reflected the effects of the 1996 settlement and the 1997 anticipated settlement in the consolidated financial statements and, in addition, reversed reserves which had previously been provided and were deemed to be no longer required.

NOTE 10

BUSINESS SEGMENT DATA

In 1998, the company adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131). SFAS No. 131 requires the disclosure of certain information about operating segments in financial statements. The company's operations are conducted through five business segments. The company's reportable segments are those that are based on the company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The electric, natural gas distribution, natural gas transmission, construction materials and mining, and oil and natural gas production businesses are substantially all located within the United States. The electric business operates electric power generation, transmission and distribution facilities in North Dakota, South Dakota, Montana and Wyoming and installs and repairs electric transmission and distribution power lines and provides related supplies, equipment and engineering services throughout the western United States and Hawaii. The natural gas distribution business provides natural gas distribution services in North Dakota, South Dakota, Montana and Wyoming. The natural gas transmission business serves the Midwestern, Southern and Central regions of the United States providing natural gas transmission and related services including storage and production along with energy marketing and management, wholesale/retail propane and energy facility construction. The construction materials and mining business produces and markets aggregates and construction materials in Alaska, California, Hawaii and Oregon, and operates lignite coal mines in Montana and North Dakota. The oil and natural gas production business is engaged in oil and natural gas acquisition, exploration and production activities throughout the United States, the Gulf of Mexico and Canada.

Segment information follows the same accounting policies as described in the Summary of Significant Accounting Policies. Segment information included in the accompanying Consolidated Balance Sheets as of December 31 and included in the Consolidated Statements of Income for the years then ended is as follows:

	Electric	Nat Gas Dist	Nat Gas Trans	Construction Materials and Mining	Oil and Nat Gas Prod	Elimin and Adjust	Total
(In thousands)							
1998							
Operating revenues:							
External	$211,453	$154,147	$133,279	$338,702(a)	$ 51,297	$ ---	$ 888,878
Intersegment	---	---	47,420	7,749	---	(47,420)(b)	7,749
Depreciation, depletion and amortization	19,798	7,150	8,463	20,562	21,813	---	77,786
Interest expense	10,304	3,728	6,426	7,402	2,413	---	30,273
Income taxes	10,204	2,681	13,977	15,155	(24,532)	---	17,485
Earnings on common stock	17,180	3,501	20,823	24,499	(32,673)	---	33,330
Other significant noncash items:							
Write-downs of oil and natural gas properties (Note 1)	---	---	---	---	66,000	---	66,000
Identifiable assets (d)	344,304	129,654	260,942	500,720	171,207	45,948 (c)	1,452,775
Capital expen	31,378	8,256	23,710	172,108	94,465	(4,275)(e)	325,642

1997							
Operating revenues:							
External	$164,351	$157,005	$ 43,784	$168,067(a)	$ 68,387	$ ---	$ 601,594
Intersegment	---	---	49,622	6,080	---	(49,622)(b)	6,080
Depreciation, depletion and amortization	17,771	7,013	5,550	10,999	24,434	---	65,767
Interest expense	10,949	3,698	8,605	4,503	2,454	---	30,209
Income taxes	7,642	2,987	8,429	4,392	7,293	---	30,743
Earnings on common stock	13,388	4,514	11,317	10,111	14,505	---	53,835
Identifiable assets (d)	326,615	128,517	227,030	235,221	162,785	33,724 (c)	1,113,892
Capital expen	27,970	8,858	13,205	41,472	30,651	(4,522)(e)	117,634
1996							
Operating revenues:							
External	$138,761	$155,012	$ 20,396	$126,275(a)	$ 68,310	$ ---	$ 508,754
Intersegment	---	---	58,224	5,947	---	(58,224)(b)	5,947
Depreciation, depletion and amortization	17,053	6,880	6,748	6,974	24,996	---	62,651
Interest expense	11,269	4,422	7,799	3,277	3,111	(1,046)(b)	28,832
Income taxes	5,859	3,507	(5,962)	5,985	6,698	---	16,087
Earnings on common stock	11,436	4,892	2,459	11,521	14,375	---	44,683
Other significant noncash items:							
Write-down of natural gas available under repurchase commitment (Note 15)	---	---	18,553	---	---	---	18,553
Identifiable assets (d)	313,815	120,645	276,843	171,283	161,647	44,940 (c)	1,089,173
Capital expen	18,674	6,255	10,890	25,063	51,821	(11,803)(e)	100,900

(a) Includes sales, for use at the Coyote Station, an electric generating station jointly owned by the company and other utilities, of (in thousands) $6,714, $5,061 and $6,358 for 1998, 1997 and 1996, respectively.
(b) Intersegment eliminations.
(c) Corporate assets consist of assets not directly assignable to a business segment (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).
(d) Includes, in the case of electric and natural gas distribution property, allocations of common utility property. Natural gas stored or available under repurchase commitment, as applicable, is included in natural gas distribution and transmission identifiable assets.
(e) Net proceeds from sale or disposition of property.

Capital expenditures for 1998 and 1997, related to acquisitions, in the preceeding table include the following noncash transactions: issuance of the company's equity securities, less treasury stock acquired, in 1998 of $138.8 million; and assumed debt and the issuance of the company's equity securities in total for 1997 of $9.9 million. In addition, natural gas transmission capital expenditures for 1996 include $763,000 for Prairielands Energy Marketing, Inc. which were not reflected in investing activities in the Consolidated Statements of Cash Flows as Prairielands was not considered a major business segment.

On March 5, 1998, the company acquired Morse Bros., Inc. and S2 - F Corp., privately held construction materials companies located in Oregon's Willamette Valley. The purchase consideration for such companies consisted of $98.2 million of the company's common stock and cash. Morse Bros., Inc. sells aggregate, ready-mixed concrete, asphaltic concrete, prestress concrete and construction services in the Willamette Valley from Portland to Eugene. S2 - F Corp. sells aggregate and construction services.

The company also acquired a number of businesses in 1998, none of which were individually material, including construction materials and mining businesses in Oregon, utility services construction and engineering businesses in California and Montana and a natural gas marketing business in Kentucky. The total purchase consideration, consisting of the company's common stock and cash, for these businesses was $62.7 million.

In 1997, the company acquired several businesses, none of which were individually material, including the remaining 50 percent interest in Hawaiian Cement (See Note 12) and utility services construction and construction supplies and equipment businesses in Oregon. The total purchase consideration, consisting of the company's common stock and cash, for these businesses was $35.2 million.

The above acquisitions were accounted for under the purchase method of accounting. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not material to the company's financial position or results of operations.

NOTE 11

EMPLOYEE BENEFIT PLANS

In 1998, the company adopted SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132). SFAS No. 132 revises employers' disclosures about pension and other postretirement benefit plans but does not change the measurement or recognition of amounts related to these benefit plans. For comparative purposes, prior year amounts have been restated.

The company has noncontributory defined benefit pension plans and other postretirement benefit plans. There were no additional minimum pension liabilities required to be recognized as of December 31, 1998 and 1997. Changes in benefit obligation and plan assets for the years ended December 31 are as follows:

(In thousands)	Pension Benefits		Other Postretirement Benefits	
	1998	1997	1998	1997
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 178,199	$ 150,829	$ 73,838	$ 65,608

NOTES TO FINANCIAL STATEMENTS (continued)

Service cost	4,509	3,889	1,502	1,272
Interest cost	12,248	11,651	4,848	4,691
Plan participants' contributions	---	---	475	379
Amendments	437	---	(4,810)	---
Actuarial (gain) loss	5,971	12,263	(1,695)	(888)
Acquisition	---	9,463	---	6,394
Benefits paid	(13,699)	(9,896)	(3,820)	(3,618)
Benefit obligation at end of year	$ 187,665	$ 178,199	$ 70,338	$ 73,838
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 225,201	$ 185,872	$ 30,595	$ 21,712
Actual return on plan assets	39,604	38,272	6,226	5,621
Employer contribution	88	265	6,067	6,501
Plan participants' contributions	---	---	475	379
Acquisition	---	10,688	---	---
Benefits paid	(13,699)	(9,896)	(3,820)	(3,618)
Fair value of plan assets at end of year	251,194	225,201	39,543	30,595
Funded status	63,529	47,002	(30,795)	(43,243)
Unrecognized actuarial gain	(73,963)	(56,844)	(8,036)	(2,679)
Unrecognized prior service cost	7,645	8,056	(1,433)	---
Unrecognized net transition obligation	(5,340)	(6,333)	31,029	36,864
Accrued benefit cost	$ (8,129)	$ (8,119)	$ (9,235)	$ (9,058)

Weighted average assumptions for the company's pension and other postretirement benefit plans as of December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	1998	1997	1998	1997
Discount rate	6.75%	7.00%	6.75%	7.00%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

Health care rate assumptions for the company's other postretirement benefit plans as of December 31 are as follows:

	1998	1997
Health care trend rate	6.50%-8.50%	7.00%-9.00%
Health care cost trend rate - ultimate	5.00%-6.00%	5.00%-6.00%
Year in which ultimate trend rate achieved	1999-2004	1999-2004

Components of net periodic benefit cost for the company's pension and other postretirement benefit plans are as follows:

	Pension Benefits	Other Postretirement Benefits

Years ended December 31, (In thousands)	1998	1997	1996	1998	1997	1996
Components of net periodic benefit cost:						
Service cost	$ 4,509	$ 3,889	$ 3,852	$ 1,502	$ 1,272	$ 1,333
Interest cost	12,248	11,651	10,823	4,848	4,691	4,701
Expected return on assets	(15,892)	(14,321)	(13,145)	(2,395)	(1,748)	(1,279)
Amortization of prior service cost	848	811	755	---	---	---
Recognized net actuarial (gain) loss	(621)	(666)	(98)	(169)	(105)	48
Amortization of net transition obligation	(994)	(988)	(990)	2,458	2,458	2,458
Net periodic benefit cost	98	376	1,197	6,244	6,568	7,261
Less amount capitalized	79	70	131	628	625	735
Net periodic benefit expense	$ 19	$ 306	$ 1,066	$ 5,616	$ 5,943	$ 6,526

The company has other postretirement benefit plans including health care and life insurance. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plan anticipates future cost-sharing changes that are consistent with the company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A 1 percentage point change in the assumed health care cost trend rates would have the following effects at December 31, 1998:

(In thousands)	1 Percentage Point Increase	1 Percentage Point Decrease
Effect on total of service and interest cost components	$ 243	$ (294)
Effect on postretirement benefit obligation	$ 3,671	$ (4,546)

The company has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments consist of life insurance carried on plan participants which is payable to the company upon the employee's death. The cost of these benefits was $2.7 million in 1998 and $2.2 million in both 1997 and 1996.

The company has stock option plans for directors, key employees and employees, which grant options to purchase shares of the company's stock. The company accounts for these option plans in accordance with APB Opinion No. 25 under which no compensation expense has been recognized. The option exercise price is the market value of the stock on the date of grant. Options granted to the key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the company. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire ten years after the date of grant. Under the stock option plans, the company is authorized to grant options for up to 4.3 million shares of common stock and has granted options on 1.9 million shares through December 31, 1998.

Had the company recorded compensation expense for the fair value of options granted consistent with SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123), net income would have been reduced on a pro forma basis by $820,000 in 1998, $51,400 in 1997 and $48,000 in 1996. On a pro forma basis, basic and diluted earnings per share for 1998 would have been reduced by $.02 and there would have been no effect for 1997 and 1996. Since SFAS No. 123 does not require this accounting to be applied to options granted prior to January 1, 1995, the resulting pro forma compensation costs may not be representative of those to be expected in future years.

A summary of the status of the stock option plans at December 31, 1998, 1997 and 1996, and changes during the years then ended are as follows:

	1998		1997		1996	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	594,180	$12.07	635,965	$11.77	703,105	$11.65
Granted	1,225,920	21.12	22,500	16.37	---	---
Forfeited	(37,875)	21.05	(13,600)	11.41	---	---
Exercised	(265,417)	11.98	(50,685)	10.50	(67,140)	10.50
Balance at end of year	1,516,808	19.17	594,180	12.07	635,965	11.77
Exercisable at end of year	333,261	$12.94	112,461	$11.67	140,646	$10.50

Exercise prices on options outstanding at December 31, 1998, range from $10.50 to $23.84 with a weighted average remaining contractual life of approximately 8 years.

The weighted average fair value of each option granted in 1998 and 1997 is $2.40 and $2.09, respectively. The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The assumptions used to estimate the fair value of options granted in 1998 and 1997 were a weighted average risk-free interest rate of 4.78 percent and 6.60 percent, respectively, a weighted average expected dividend yield of 5.13 percent and 5.48 percent, respectively, an expected life of 7 years and a weighted average expected volatility of 16.27 percent and 14.51 percent, respectively.

The company sponsors various defined contribution plans for eligible employees. Costs incurred by the company under these plans were $3.1 million in 1998, $2.1 million in 1997 and $1.9 million in 1996. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 12

PARTNERSHIP INVESTMENT

In September 1995, KRC Holdings, Inc., through its wholly owned subsidiary, Knife River Hawaii, Inc., acquired a 50 percent interest in Hawaiian Cement, which was previously owned by Lone Star Industries, Inc. Knife River Dakota, Inc., a wholly owned subsidiary of KRC Holdings, Inc., acquired the remaining 50 percent interest in Hawaiian Cement from the previous owner, Adelaide Brighton Cement (Hawaii), Inc. of Adelaide, Australia, in July 1997.

In August 1997, the company began consolidating Hawaiian Cement into its financial statements. Prior to August 1997, the company's net investment in Hawaiian Cement was not consolidated and was accounted for by the equity method. The company's share of operating results for the seven months ended July 31, 1997, and the year ended December 31, 1996, is included in "Other income -- net" in the accompanying Consolidated Statements of Income for the years ended December 31, 1997 and 1996, respectively. Summarized operating results for Hawaiian Cement for the seven months ended July 31, 1997, and for the year ended December 31, 1996, when accounted for by the equity method, are as follows: net sales of $33.5 million and $70.1 million; operating margin of $4.7 million and $9.9 million; and income before income taxes of $2.0 million and $5.4 million, respectively.

NOTE 13

JOINTLY OWNED FACILITIES

The consolidated financial statements include the company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The company's share of the Big Stone Station and Coyote Station operating expenses is reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

(In thousands)	1998	1997
Big Stone Station:		
Utility plant in service	$ 49,762	$ 49,467
Less accumulated depreciation	28,781	27,971
	$ 20,981	$ 21,496
Coyote Station:		
Utility plant in service	$121,726	$121,604
Less accumulated depreciation	56,770	53,107
	$ 64,956	$ 68,497

NOTE 14

REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

General rate proceedings

Williston Basin had pending with the FERC a general natural gas rate change application implemented in 1992. In October 1997, Williston Basin appealed to the United States Court of Appeals for the D.C. Circuit (D.C. Circuit Court) certain issues decided by the FERC in prior orders concerning the 1992 proceeding. Williston Basin is awaiting a decision from the D.C. Circuit Court.

In June 1995, Williston Basin filed a general rate increase application with the FERC. As a result of FERC orders issued after Williston Basin's application was filed, Williston Basin filed revised base rates in December 1995 with the FERC resulting in an increase of $8.9 million or 19.1 percent over the then current effective rates. Williston Basin began collecting such increase effective January 1, 1996, subject to refund. On July 29, 1998, the FERC issued an order which addressed various issues including storage cost allocations, return on equity and throughput. On August 28, 1998, Williston Basin requested rehearing of such order.

Reserves have been provided for a portion of the revenues that have been collected subject to refund with respect to pending regulatory proceedings and to reflect future resolution of certain issues with the FERC. Williston Basin believes that such reserves are adequate based on its assessment of the ultimate outcome of the various proceedings.

NOTE 15

NATURAL GAS REPURCHASE COMMITMENT

The company has offered for sale since 1984 the inventoried natural gas owned by Frontier, a special purpose, nonaffiliated corporation. Through an agreement, Williston Basin is obligated to repurchase all of the natural gas at Frontier's original cost and reimburse Frontier for all of its financing and general administrative costs. Frontier has financed the purchase of the natural gas under a term loan agreement with several banks. At December 31, 1998 and 1997, borrowings totaled $14.8 million and $32.0 million, respectively, at a weighted average interest rate of 6.19 percent and 6.63 percent, respectively. At December 31, 1998 and 1997, the natural gas repurchase commitment of $14.3 million and $30.4 million, respectively, is reflected on the company's Consolidated Balance Sheets under "Other liabilities" and $551,000 and $1.6 million, respectively, is reflected under "Other accrued liabilities." The financing costs associated with this repurchase commitment, consisting principally of interest and related financing fees, approximated $5.7 million in 1996. The costs incurred in 1998 and 1997 were not material and are included in "Other income -- net" on the Consolidated Statements of Income. The term loan agreement will terminate on October 2, 1999, subject to an option to renew this agreement upon the lenders' consent for up to five years, unless terminated earlier by the occurrence of certain events.

The FERC has issued orders that have held that storage costs should be allocated to this gas, prospectively beginning May 1992, as opposed to being included in rates applicable to Williston Basin's customers. These storage costs, as initially allocated to the Frontier gas, approximated $2.1 million annually, for which Williston Basin has provided reserves. Williston Basin appealed these orders to the D.C. Circuit Court which in December 1996 issued its order ruling that the FERC's actions in allocating storage capacity costs to the Frontier gas were appropriate. On August 28, 1998, Williston Basin requested rehearing of the July 29, 1998 FERC order which addressed various issues, including a requirement that storage deliverability costs be allocated to the Frontier gas.

Williston Basin sells and transports natural gas held under the repurchase commitment. In the third quarter of 1996, Williston Basin, based on a number of factors including differences in regional natural gas prices and natural gas sales occurring at that time, wrote down 43.0 MMdk of this gas to its then current value. The value of this gas was determined using the sum of discounted cash flows of expected future sales occurring at then current regional natural gas prices as adjusted for anticipated future price increases. This resulted in a write-down aggregating $18.6 million ($11.4 million after tax). In addition, Williston Basin wrote off certain other costs related to this natural gas of approximately $2.5 million ($1.5 million after tax). The amounts related to this write-down are included in "Costs on natural gas repurchase commitment" in the Consolidated Statements of Income. At December 31, 1998 and 1997, natural gas held under the repurchase commitment of $6.9 million and $14.6 million, respectively, is included in the company's Consolidated Balance Sheets under "Deferred charges and other assets." The amount of this natural gas in storage as of December 31, 1998 was 7.0 MMdk.

NOTE 16

COMMITMENTS AND CONTINGENCIES

Pending litigation

In November 1993, the estate of W.A. Moncrief (Moncrief), a producer from whom Williston Basin purchased a portion of its natural gas supply, filed suit in Federal District Court for the District of Wyoming (Federal District Court) against Williston Basin and the company disputing certain price and volume issues under the contract.

Through the course of this action Moncrief submitted damage calculations which totaled approximately $19 million or, under its alternative pricing theory, approximately $39 million.

In June 1997, the Federal District Court issued its order awarding Moncrief damages of approximately $15.6 million. In July 1997, the Federal District Court issued an order limiting Moncrief's reimbursable costs to post-judgment interest, instead of both pre- and post-judgment interest as Moncrief had sought. In August 1997, Moncrief filed a notice of appeal with the United States Court of Appeals for the Tenth Circuit (U.S. Court of Appeals) related to the Federal District Court's orders. In September 1997, Williston Basin and the company filed a notice of cross-appeal. Oral argument before the U.S. Court of Appeals was held September 23, 1998. Williston Basin and the company are awaiting a decision from the U.S. Court of Appeals.

Williston Basin believes that it is entitled to recover from customers virtually all of the costs which might ultimately be incurred as a result of this litigation as gas supply realignment transition costs pursuant to the provisions of the FERC's Order 636. However, the amount of costs that can ultimately be recovered is subject to approval by the FERC and market conditions.

In December 1993, Apache Corporation (Apache) and Snyder Oil Corporation (Snyder) filed suit in North Dakota Northwest Judicial District Court (North Dakota District Court) against Williston Basin and the company. Apache and Snyder are oil and natural gas producers which had processing agreements with Koch Hydrocarbon Company (Koch). Williston Basin and the company had a natural gas purchase contract with Koch. Apache and Snyder have alleged they are entitled to damages for the breach of Williston Basin's and the company's contract with Koch. Williston Basin and the company believe that if Apache and Snyder have any legal claims, such claims are with Koch, not with Williston Basin or the company as Williston Basin, the company and Koch have settled their disputes. Apache and Snyder have submitted damage estimates under differing theories aggregating up to $4.8 million without interest. A motion to intervene in the case by several other producers, all of which had contracts with Koch but not with Williston Basin, was denied in December 1996. The trial before the North Dakota District Court was completed in November 1997.

On November 25, 1998, the North Dakota District Court entered an order directing the entry of judgment in favor of Williston Basin and the company. On December 15, 1998, Apache and Snyder filed a motion for relief asking the North Dakota District Court to reconsider its November 25, 1998 order.

In a related matter, in March 1997, a suit was filed by nine other producers, several of which had unsuccessfully tried to intervene in the Apache and Snyder litigation, against Koch, Williston Basin and the company. The parties to this suit are making claims similar to those in the Apache and Snyder litigation, although no specific damages have been stated.

In Williston Basin's opinion, the claims of Apache and Synder are without merit and overstated and the claims of the nine other producers are without merit. If any amounts are ultimately found to be due, Williston Basin plans to file with the FERC for recovery from customers. However, the amount of costs that can ultimately be recovered is subject to approval by the FERC and market conditions.

In November 1995, a suit was filed in District Court, County of Burleigh, State of North Dakota (State District Court) by Minnkota Power Cooperative, Inc., Otter Tail Power Company, Northwestern Public Service Company and Northern Municipal Power Agency (Co-owners), the owners of an aggregate 75 percent interest in the Coyote electric generating station (Coyote Station), against the company (an owner of a 25 percent interest in the Coyote Station) and Knife River. In its complaint, the Co-owners have alleged a breach of contract against Knife River with respect to the long-term coal supply agreement (Agreement) between the owners of the Coyote Station and Knife River. The Co-owners have requested a determination by the State District Court of the pricing mechanism to be applied to the Agreement and have further requested damages during the term of such alleged breach on the difference between the prices charged by Knife River and the prices that may ultimately be determined by the State District Court. The Co-owners also alleged a breach of fiduciary duties by the company as operating agent of the Coyote Station, asserting essentially that the company was unable to cause Knife River to reduce its coal price sufficiently under the Agreement, and the Co-owners are seeking damages in an unspecified amount. In May 1996, the State District Court stayed the suit filed by the Co-owners pending arbitration, as provided for in the Agreement.

In September 1996, the Co-owners notified the company and Knife River of their demand for arbitration of the pricing dispute that had arisen under the Agreement. The demand for arbitration, filed with the American Arbitration Association (AAA), did not make any direct claim against the company in its capacity as operator of the Coyote Station. The Co-owners requested that the arbitrators make a determination that the pricing dispute is not a proper subject for arbitration. By an April 1997 order, the arbitration panel concluded that the claims raised by the Co-owners are arbitrable. The Co-owners have requested the arbitrators to make a determination that the prices charged by Knife River were excessive and that the Co-owners should be awarded damages, based upon the difference between the prices that Knife River charged and a "fair and equitable" price. Upon application by the company and Knife River, the AAA administratively determined that the company was not a proper party defendant to the arbitration, and the arbitration is proceeding against Knife River. On October 9, 1998, a hearing before the arbitration panel was completed. At the hearing the Co-owners requested damages of approximately $24 million, including interest, plus a reduction in the future price of coal under the

Agreement. The company is currently awaiting a decision from the arbitration panel. Although unable to predict the outcome of the arbitration, Knife River and the company believe that the Co-owners' claims are without merit and intend to vigorously defend the prices charged pursuant to the Agreement.

The company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that there is no pending legal proceeding against or involving the company, except those discussed above, for which the outcome is likely to have a material adverse effect upon the company's financial position or results of operations.

Environmental matters

Montana-Dakota and Williston Basin discovered polychlorinated biphenyls (PCBs) in portions of their natural gas systems and informed the United States Environmental Protection Agency (EPA) in January 1991. Montana-Dakota and Williston Basin believe the PCBs entered the system from a valve sealant. In January 1994, Montana-Dakota, Williston Basin and Rockwell International Corporation (Rockwell), manufacturer of the valve sealant, reached an agreement under which Rockwell has reimbursed and will continue to reimburse Montana-Dakota and Williston Basin for a portion of certain remediation costs. On the basis of findings to date, Montana-Dakota and Williston Basin estimate future environmental assessment and remediation costs will aggregate $3 million to $15 million. Based on such estimated cost, the expected recovery from Rockwell and the ability of Montana-Dakota and Williston Basin to recover their portions of such costs from ratepayers, Montana-Dakota and Williston Basin believe that the ultimate costs related to these matters will not be material to each of their respective financial positions or results of operations.

Electric purchased power commitments

Through October 31, 2006, Montana-Dakota has contracted to purchase 66,400 kW of participation power from Basin Electric Power Cooperative. In addition, Montana-Dakota, under a power supply contract through December 31, 2006, is purchasing up to 55,000 kW of capacity from Black Hills Power and Light Company.

NOTE 17

QUARTERLY DATA (UNAUDITED)

The following unaudited information shows selected items by quarter for the years 1998 and 1997:

(In thousands, except per share amounts)	First Quarter	Second Quarter*	Third Quarter	Fourth Quarter*
1998				
Operating revenues	$ 170,122	$ 179,715	$ 269,978	$ 276,812
Operating expenses	137,913	186,310	227,283	274,178
Operating income (loss)	32,209	(6,595)	42,695	2,634
Net income (loss)	17,793	(5,785)	22,538	(439)
Earnings (loss) per common share:				
Basic	.39	(.12)	.42	(.01)
Diluted	.39	(.12)	.42	(.01)
Weighted average common shares outstanding:				

Basic	45,375	50,936	52,703	53,021
Diluted	45,629	50,936	53,062	53,021
1997				
Operating revenues	$ 139,811	$ 125,380	$ 163,699	$ 178,784
Operating expenses	109,055	106,932	134,675	145,451
Operating income	30,756	18,448	29,024	33,333
Net income	14,597	8,741	14,195	17,084
Earnings per common share:				
Basic	.34	.20	.32	.39
Diluted	.33	.20	.32	.39
Weighted average common shares outstanding:				
Basic	42,894	43,104	43,577	43,676
Diluted	43,019	43,247	43,733	43,901

* Reflects $20.0 million and $19.9 million in noncash after-tax write-downs of oil and natural gas properties for the second quarter and fourth quarter of 1998, respectively.

Certain company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

NOTE 18

OIL AND NATURAL GAS ACTIVITIES (UNAUDITED)

Fidelity Oil Group is involved in the acquisition, exploration, development and production of oil and natural gas properties. Fidelity's operations vary from the acquisition of producing properties with potential development opportunities to exploration and are located throughout the United States, the Gulf of Mexico and Canada. Fidelity shares revenues and expenses from the development of specified properties in proportion to its interests.

Williston Basin Interstate Pipeline Company owns in fee or holds natural gas leases and operating rights primarily applicable to the shallow rights (above 2,000 feet) in the Cedar Creek Anticline in southeastern Montana and to all rights in the Bowdoin area located in north-central Montana.

The following information includes the company's proportionate share of all its oil and natural gas interests held by both Fidelity and Williston Basin.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to oil and natural gas producing activities at December 31:

(In thousands)	1998	1997	1996
Subject to amortization	$ 266,301	$ 252,291	$ 223,409
Not subject to amortization	22,153	9,408	6,792
Total capitalized costs	288,454	261,699	230,201
Accumulated depreciation, depletion and amortization	111,472	95,611	71,554
Net capitalized costs	$ 176,982	$ 166,088	$ 158,647

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/1998	Dec. 31, 1998

NOTES TO FINANCIAL STATEMENTS (continued)

NOTE: Net capitalized costs as of December 31, 1998 reflect noncash write-downs of the company's oil and natural gas properties as discussed in Note 1.

Capital expenditures, including those not subject to amortization, related to oil and natural gas producing activities are as follows:

Years ended December 31, (In thousands)	1998	1997	1996
Acquisitions	$ 63,419	$ 59	$23,284
Exploration	15,976	13,344	8,101
Development	21,545	18,874	19,979
Total capital expenditures	$100,940	$32,277	$51,364

The following summary reflects income resulting from the company's operations of oil and natural gas producing activities, excluding corporate overhead and financing costs:

Years ended December 31, (In thousands)	1998	1997	1996
Revenues*	$ 61,831	$77,756	$75,335
Production costs	19,419	23,251	21,296
Depreciation, depletion and amortization	23,050	24,864	25,629
Write-downs of oil and natural gas properties (Note 1)	66,000	---	---
Pretax income	(46,638)	29,641	28,410
Income tax expense (benefit)	(19,268)	10,968	10,875
Results of operations for producing activities	$(27,370)	$18,673	$17,535

*Includes $10.5 million, $9.4 million and $7.0 million of revenues for 1998, 1997 and 1996, respectively, related to Williston Basin's natural gas production activities which are included in "Natural gas" operating revenues in the Consolidated Statements of Income.

The following table summarizes the company's estimated quantities of proved oil and natural gas reserves at December 31, 1998, 1997 and 1996, and reconciles the changes between these dates. Estimates of economically recoverable oil and natural gas reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

	1998		1997		1996	
(In thousands of barrels/Mcf)	Oil	Natural Gas	Oil	Natural Gas	Oil	Natural Gas
Proved developed and undeveloped reserves:						
Balance at beginning of year	14,900	184,900	16,100	200,200	14,200	179,000
Production	(1,900)	(20,700)	(2,100)	(20,400)	(2,100)	(20,400)
Extensions and discoveries	200	21,300	600	12,100	600	27,000
Purchases of proved						

SCHEDULE 13A

SCHEDULE 40A

SCHEDULE 10A

SCHEDULE 10A

SCHEDULE 10A

SCHEDULE 1[illegible]A

SCHEDULE [illegible]

SCHEDULE 10A

SCHEDULE [illegible]

SCHEDULE 10A

SCHEDULE 40A

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SCHEDULE 13A

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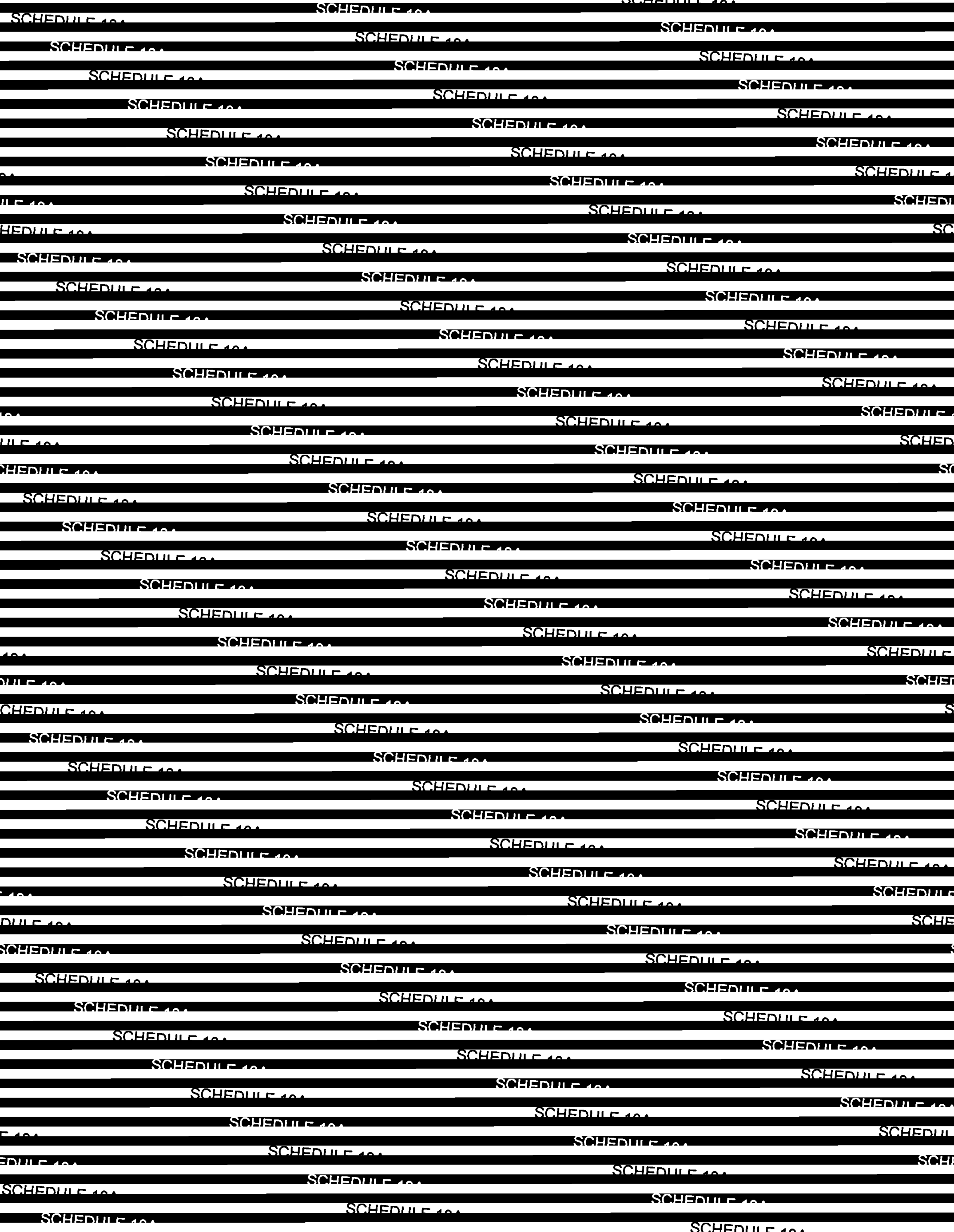
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SCHEDULE 12A

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reserves	2,000	56,600	---	200	2,900	9,900
Sales of reserves in place	---	(100)	(200)	(2,300)	(700)	(3,700)
Revisions to previous estimates due to improved secondary recovery techniques and/or changed economic conditions	(3,700)	1,600	500	(4,900)	1,200	8,400
Balance at end of year	11,500	243,600	14,900	184,900	16,100	200,200
Proved developed reserves:						
January 1, 1996	13,600	156,400				
December 31, 1996	15,400	168,200				
December 31, 1997	14,500	163,800				
December 31, 1998	10,700	193,000				

Virtually all of the company's interests in oil and natural gas reserves are located in the continental United States. Reserve interests at December 31, 1998, applicable to the company's $411,000 net investment in oil and natural gas properties located in Canada comprise approximately 2 percent of the total reserves.

The standardized measure of the company's estimated discounted future net cash flows of total proved reserves associated with its various oil and natural gas interests at December 31 is as follows:

(In thousands)	1998	1997	1996
Future net cash flows before income taxes	$246,700	$306,600	$580,300
Future income tax expenses	40,500	86,600	194,200
Future net cash flows	206,200	220,000	386,100
10% annual discount for estimated timing of cash flows	81,100	81,000	152,100
Discounted future net cash flows relating to proved oil and natural gas reserves	$125,100	$139,000	$234,000

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

(In thousands)	1998	1997	1996
Beginning of year	$139,000	$234,000	$120,900
Net revenues from production	(42,400)	(54,500)	(54,000)
Change in net realization	(70,500)	(158,400)	125,800
Extensions, discoveries and improved recovery, net of future production-related costs	18,200	19,400	43,500
Purchases of proved reserves	51,000	200	49,600
Sales of reserves in place	(100)	(2,800)	(6,700)

Changes in estimated future development costs, net of those incurred during the year	(16,600)	7,700	(2,400)
Accretion of discount	18,600	32,800	16,900
Net change in income taxes	30,100	62,100	(69,200)
Revisions of previous quantity estimates	(1,600)	(1,300)	8,700
Other	(600)	(200)	900
Net change	(13,900)	(95,000)	113,100
End of year	$125,100	$139,000	$234,000

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end oil and natural gas prices. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates (adjusted for permanent differences and tax credits) to estimated net future pretax cash flows.

NOTE 19

INVESTMENT IN SUBSIDIARY

The Respondent, through its wholly-owned subsidiary, Centennial Enery Holdings, Inc., owns Williston Basin Interstate Pipeline Company, Knife River Corporation, Fidelity Oil Group and Utility Services, Inc.

As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $322,000,585 and $226,428,522; current and accrued assets would increase by $159,563,049 and $101,878,421; deferred debits would increase by $39,533,812 and $53,014,772; preferred stock would decrease by $100,000 and $100,000; long-term debt would increase by $239,072,884 and $141,095,646; other noncurrent liabilities and current and accrued liabilities would increase by $91,779,591 and $88,616,330; deferred credits would increase by $193,970,783 and $151,709,739 as of December 31, 1998 and 1997, respectively. Furthermore, operating revenues would increase by $595,259,613 and $309,078,645; and operating expenses, excluding income taxes, would increase by $564,511,507 and $239,234,512 for the year ended December 31, 1998 and 1997, respectively. In addition, net cash provided by operating activities would increase by $118,899,000; net cash used in investing activities would increase by $17,207,000; net cash used in financing activities would increase by $90,972,000; and the net change in cash and cash equivalents would increase by $10,720,000 for the year ended December 31, 1998. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

Company Name: **Montana-Dakota Utilities Co.**

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 1998

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Intangible Plant**			
3				
4	301 Organization			
5	302 Franchises & Consents			
6	303 Miscellaneous Intangible Plant	$619,544	$630,783	1.81%
7				
8	**TOTAL Intangible Plant**	$619,544	$630,783	1.81%
9				
10	**Production Plant**			
11	Production & Gathering Plant			
12				
13	325.1 Producing Lands			
14	325.2 Producing Leaseholds			
15	325.3 Gas Rights			
16	325.4 Rights-of-Way			
17	325.5 Other Land & Land Rights			
18	326 Gas Well Structures			
19	327 Field Compressor Station Structures			
20	328 Field Meas. & Reg. Station Structures			
21	329 Other Structures			
22	330 Producing Gas Wells-Well Construction			
23	331 Producing Gas Wells-Well Equipment		NOT	
24	332 Field Lines		APPLICABLE	
25	333 Field Compressor Station Equipment			
26	334 Field Meas. & Reg. Station Equipment			
27	335 Drilling & Cleaning Equipment			
28	336 Purification Equipment			
29	337 Other Equipment			
30	338 Unsuccessful Exploration & Dev. Costs			
31				
32	**Total Production & Gathering Plant**			
33				
34	Products Extraction Plant			
35				
36	340 Land & Land Rights			
37	341 Structures & Improvements			
38	342 Extraction & Refining Equipment			
39	343 Pipe Lines			
40	344 Extracted Products Storage Equipment			
41	345 Compressor Equipment		NOT	
42	346 Gas Measuring & Regulating Equipment		APPLICABLE	
43	347 Other Equipment			
44				
45	**Total Products Extraction Plant**			
46				
47	**TOTAL Production Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 1998

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Natural Gas Storage and Processing Plant**			
3				
4	Underground Storage Plant			
5				
6	350.1 Land			
7	350.2 Rights-of-Way			
8	351 Structures & Improvements			
9	352 Wells			
10	352.1 Storage Leaseholds & Rights			
11	352.2 Reservoirs			
12	352.3 Non-Recoverable Natural Gas			
13	353 Lines		NOT	
14	354 Compressor Station Equipment		APPLICABLE	
15	355 Measuring & Regulating Equipment			
16	356 Purification Equipment			
17	357 Other Equipment			
18				
19	**Total Underground Storage Plant**			
20				
21	Other Storage Plant			
22				
23	360 Land & Land Rights			
24	361 Structures & Improvements			
25	362 Gas Holders			
26	363 Purification Equipment			
27	363.1 Liquification Equipment			
28	363.2 Vaporizing Equipment			
29	363.3 Compressor Equipment		NOT	
30	363.4 Measuring & Regulating Equipment		APPLICABLE	
31	363.5 Other Equipment			
32				
33	**Total Other Storage Plant**			
34				
35	**TOTAL Natural Gas Storage and Processing Plant**			
36				
37	**Transmission Plant**			
38				
39	365.1 Land & Land Rights			
40	365.2 Rights-of-Way			
41	366 Structures & Improvements			
42	367 Mains			
43	368 Compressor Station Equipment			
44	369 Measuring & Reg. Station Equipment		NOT	
45	370 Communication Equipment		APPLICABLE	
46	371 Other Equipment			
47				
48	**TOTAL Transmission Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 1998

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Distribution Plant**			
3					
4	374	Land & Land Rights	$34,881	$34,881	
5	375	Structures & Improvements	190,323	190,323	
6	376	Mains	18,993,606	19,421,758	2.25%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	517,797	534,003	3.13%
9	379	Meas. & Reg. Station Equipment-City Gate	131,088	130,788	-0.23%
10	380	Services	9,332,712	9,837,617	5.41%
11	381	Meters	8,282,885	8,645,180	4.37%
12	382	Meter Installations			
13	383	House Regulators	1,228,879	1,276,292	3.86%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	107,121	120,525	12.51%
16	386	Other Prop. on Customers' Premises 1/	169,866	161,799	-4.75%
17	387	Other Equipment	712,704	750,006	5.23%
18					
19		**TOTAL Distribution Plant**	$39,701,862	$41,103,172	3.53%
20					
21		**General Plant**			
22					
23	389	Land & Land Rights	$26,744	$26,744	
24	390	Structures & Improvements	202,818	236,084	16.40%
25	391	Office Fumiture & Equipment	92,793	115,072	24.01%
26	392	Transportation Equipment	1,397,752	1,412,987	1.09%
27	393	Stores Equipment	48,508	48,508	
28	394	Tools, Shop & Garage Equipment 1/	815,250	836,871	2.65%
29	395	Laboratory Equipment	97,523	97,463	-0.06%
30	396	Power Operated Equipment	1,124,992	1,203,367	6.97%
31	397	Communication Equipment	332,289	332,413	0.04%
32	398	Miscellaneous Equipment	40,376	44,495	10.20%
33	399	Other Tangible Property			
34					
35		**TOTAL General Plant**	$4,179,045	$4,354,004	4.19%
36					
37		**Common Plant**			
38					
39	389	Land & Land Rights	$183,605	$186,902	1.80%
40	390	Structures & Improvements	2,200,748	2,262,836	2.82%
41	391	Office Fumiture & Equipment	1,346,116	1,366,095	1.48%
42	392	Transportation Equipment	493,179	539,848	9.46%
43	393	Stores Equipment	12,956	13,106	1.16%
44	394	Tools, Shop & Garage Equipment	106,764	114,621	7.36%
45	397	Communication Equipment	370,048	417,024	12.69%
46	398	Miscellaneous Equipment	57,344	60,146	4.89%
47					
48		**TOTAL Common Plant**	$4,770,760	$4,960,578	3.98%
49					
50		**TOTAL Gas Plant in Service**	$49,271,211	$51,048,537	3.61%

1/ Includes gas plant leased to others.

Company Name: Montana-Dakota Utilities Co.

STATEMENT OF CASH FLOWS

SCHEDULE 23

Year: 1998

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$54,617,094	$34,106,960	-37.55%
5	Depreciation	24,505,387	25,278,905	3.16%
6	Amortization	1,472,732	527,498	-64.18%
7	Deferred Income Taxes - Net	(674,722)	(3,086,777)	357.49%
8	Investment Tax Credit Adjustments - Net	(1,149,623)	(974,672)	-15.22%
9	Change in Operating Receivables - Net	2,126,444	462,570	-78.25%
10	Change in Materials, Supplies & Inventories - Net	(4,181,416)	271,007	106.48%
11	Change in Operating Payables & Accrued Liabilities - Net	(4,436,966)	1,248,453	128.14%
12	Change in Other Regulatory Assets	1,919,866	702,737	-63.40%
13	Change in Other Regulatory Liabilities	1,782,876	289,604	-83.76%
14	Allowance for Funds Used During Construction (AFUDC)	(335,502)	(199,488)	-40.54%
15	Change in Other Assets & Liabilities - Net	18,745,195	(23,158,807)	-223.55%
16	Less Undistributed Earnings from Subsidiary Companies	(36,879,250)	(15,920,717)	-56.83%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$57,512,115	$19,547,273	-66.01%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($28,895,675)	($22,361,401)	-22.61%
23	Acquisition of Other Noncurrent Assets	(206,853)	(15,283,378)	7288.52%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(14,840,704)	(175,311,592)	1081.29%
26	Contributions and Advances from Affiliates	17,194,000	26,063,100	51.58%
27	Disposition of Investments in and Advances to Affiliates	2,000,000	2,000,000	
28	Other Investing Activities: Depreciation on Nonutility Plant	969	2,222	129.31%
29	**Net Cash Provided by/(Used in) Investing Activities**	($24,748,263)	($184,891,049)	647.09%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt	$30,000,000	$37,000,000	23.33%
34	Preferred Stock			
35	Common Stock	14,440,704	175,311,616	1114.01%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper	(2,000,000)	15,000,000	850.00%
39	Payment for Retirement of:			
40	Long-Term Debt	(42,300,000)	(20,300,000)	-52.01%
41	Preferred Stock	(100,000)	(100,000)	
42	Common Stock			
43	Other:			
44	Net Decrease in Short-Term Debt			
45	Dividends on Preferred Stock	(781,909)	(776,808)	-0.65%
46	Dividends on Common Stock	(32,654,520)	(40,469,690)	23.93%
47	Other Financing Activities (explained on attached page)			
48	**Net Cash Provided by (Used in) Financing Activities**	($33,395,725)	$165,665,118	596.07%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($631,873)	$321,342	150.86%
51	**Cash and Cash Equivalents at Beginning of Year**	$6,786,112	$6,154,239	-9.31%
52	**Cash and Cash Equivalents at End of Year**	$6,154,239	$6,475,581	5.22%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 24

LONG TERM DEBT

Year: 1998

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	8.25 % Secured MTN, Series A	04/92	04/07	$30,000,000	$26,111,796	$30,000,000	8.25%	$3,053,100	10.18%
2	8.60 % Secured MTN, Series A	04/92	04/12	35,000,000	28,906,532	35,000,000	8.60%	3,857,000	11.02%
3	6.52 % Secured MTN, Series A	09/97	10/04	15,000,000	14,082,923	15,000,000	6.52%	1,171,650	7.81%
4	6.71 % Secured MTN, Series A	09/97	10/09	15,000,000	13,488,404	15,000,000	6.71%	1,229,250	8.20%
5	5.83 % Secured MTN, Series A	09/98	10/08	15,000,000	14,813,914	15,000,000	5.83%	912,900	6.09%
6	Grant County 6.20 % PCN	03/74	03/04	5,600,000	5,427,042	3,400,000	6.20%	222,904	6.56%
7	Mercer County 6.65 % 2/	06/92	06/22	15,000,000	14,061,276	15,000,000	6.65%	1,093,200	7.29%
8	Richland County 6.65 % 2/	06/92	06/22	3,250,000	3,063,677	3,250,000	6.65%	235,398	7.24%
9	Morton County 6.65 % 2/	06/92	06/22	2,600,000	2,420,986	2,600,000	6.65%	190,944	7.34%
10	Term Loan 3/								
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26	TOTAL			$136,450,000	$122,376,550	$134,250,000		$11,966,346	8.91%

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquistion and redemption.
2/ Pollution Control Refunding Revenue Bonds.
3/ The company has $50 million available under revolving lines of credit, of which $40 million was outstanding at year end.
The average 1998 term loan rate was 6.562%.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 25

PREFERRED STOCK

Year: 1998

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price 1/	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	4.50 % Cumulative	01/51	100,000	$100	$105	$10,000,000	4.50%	$10,000,000	$450,000	4.50%
2	4.70 % Cumulative	12/55	50,000	100	102	5,000,000	4.70%	5,000,000	235,000	4.70%
3	5.10 % Cumulative	05/61	50,000	100	102	4,947,548	5.29%	1,700,000	89,845	5.29%
4										
5										
6										
7										
8										
9										
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28										
29										
30										
31										
32	**TOTAL**					$19,947,548		$16,700,000	$774,845	4.64%

1/ Plus accrued dividends.

COMMON STOCK

Year: 1998

		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 2/
1									
2									
3									
4	January 1/	43,714,998	$8.98						
5									
6	February 1/	43,714,998	8.82						
7									
8	March 1/	48,534,067	9.91	$0.39	$0.1917	50.85%	$25.25	$18.83	19.2 X
9									
10	April 1/	50,053,349	10.44						
11									
12	May 1/	51,369,923	10.31						
13									
14	June 1/ 3/	51,369,923	10.07	(0.12)	0.1917	-259.75%	25.13	21.13	25.9 X
15									
16	July	52,366,255	10.49						
17									
18	August	52,859,641	10.43						
19									
20	September	52,889,397	10.56	0.42	0.2000	52.38%	28.88	22.06	25.0 X
21									
22	October	53,004,471	10.75						
23									
24	November	53,025,201	10.66						
25									
26	December 3/	53,033,430	10.39	(0.01)	0.2000	-2100.00%	27.63	24.88	39.9 X
27									
28									
29									
30	TOTAL Year End	53,033,430	$10.39	$0.68	$0.7834	-15.21%			39.9 X

1/ Restated to reflect the company's three-for-two stock split effected in July 1998.
2/ Calculated on 12 months ended using closing stock price.
3/ Earnings per share amounts reflect $20.0 million and $19.9 million in noncash, after-tax write-downs of oil and natural gas properties for the second and fourth quarter, respectively.

MONTANA EARNED RATE OF RETURN

Year: 1998

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	$49,271,211	$51,048,537	3.61%
3	108	(Less) Accumulated Depreciation	28,108,199	29,724,554	5.75%
4					
5		**NET Plant in Service**	$21,163,012	$21,323,983	0.76%
6					
7		CWIP in Service Pending Reclassification	$150,900	$121,031	-19.79%
8					
9		Additions			
10	154, 156	Materials & Supplies	$357,083	$316,985	-11.23%
11	165	Prepayments	155,644	163,422	5.00%
12		Prepaid Demand/Commodity Charges	1,620,083	1,562,472	-3.56%
13		Gas in Underground Storage	4,003,055	3,965,362	-0.94%
14		Unamoritzed Gas IRP	268,248	232,540	-13.31%
15					
16		**TOTAL Additions**	$6,404,113	$6,240,781	-2.55%
17					
18		Deductions			
19	190	Accumulated Deferred Income Taxes	$3,415,885	$3,319,418	-2.82%
20	252	Customer Advances for Construction	39,411	150,748	282.50%
21	255	Accumulated Def. Investment Tax Credits	375,862	335,606	-10.71%
22		Other Deductions			
23					
24		**TOTAL Deductions**	$3,831,158	$3,805,772	-0.66%
25		**TOTAL Rate Base**	$23,886,867	$23,880,023	-0.03%
26					
27		**Net Earnings**	$2,583,921	$1,998,801	-22.64%
28					
29		**Rate of Return on Average Rate Base**	11.74%	8.37%	-28.71%
30					
31		**Rate of Return on Average Equity**	14.70%	8.01%	-45.51%
32					
33		Major Normalizing Adjustments & Commission			
34		Ratemaking adjustments to Utility Operations 1/			
35					
36		Adjustment to Operating Revenues			
37		Weather Normalization	$112,220	$279,531	149.09%
38		Late Payment Revenue	24,203	24,947	3.07%
39					
40		Adjustment to Operating Expenses			
41		Elimination of Promotional & Institutional Advertising	(13,201)	(15,666)	18.67%
42					
43		Total Adjustments to Operating Income	$149,624	$320,144	113.97%
44					
45					
46		**Adjusted Rate of Return on Average Rate Base**	12.42%	9.71%	-21.82%
47					
48		**Adjusted Rate of Return on Average Equity**	16.24%	11.20%	-31.03%

1/ Updated amounts, net of taxes.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 28

MONTANA COMPOSITE STATISTICS

Year: 1998

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$47,676
5	107	Construction Work in Progress	162
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	17
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	317
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	29,725
12	252	Contributions in Aid of Construction	151
13			
14		**NET BOOK COSTS**	$18,296
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$45,275
19			
20	403 - 407	Depreciation & Amortization Expenses	$1,953
21		Federal & State Income Taxes	629
22		Other Taxes	1,865
23		Other Operating Expenses	38,829
24		TOTAL Operating Expenses	$43,276
25			
26		Net Operating Income	$1,999
27			
28	415 - 421.1	Other Income	301
29	421.2 - 426.5	Other Deductions	237
30			
31		**NET INCOME**	$2,063
32			
33		Customers (Intrastate Only) 1/	
34			
35		Year End Average:	
36		Residential	61,443
37		Firm General	7,366
38		Small Interruptible	37
39		Large Interruptible	6
40			
41		**TOTAL NUMBER OF CUSTOMERS**	68,852
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	91
46		Average Annual Residential Cost per (Dkt) ($) * 2/ * Avg annual cost = [(cost per Dkt x annual use) +	$5.24
47		(mo. svc chrg x 12)]/annual use	
48		Average Residential Monthly Bill	$37.62
49		Gross Plant per Customer	$692

1/ Reflects bills divided by twelve.

2/ Reflects cost per dk effective December 1, 1998.

MONTANA CUSTOMER INFORMATION

Year: 1998

	City/Town	Population (Include Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	270	133	23		156
2	Billings	81,151	37,476	3,464		40,940
3	Bridger	692	393	64		457
4	Crow Agency	6,370	303	58		361
5	Edgar	Not Available	101	8		109
6	Fromberg	370	261	21		282
7	Hardin	2,940	1,207	198		1,405
8	Joliet	522	336	37		373
9	Laurel	5,686	3,154	250		3,404
10	Park City	375	448	22		470
11	Pryor	654	91	10		101
12	Rockvale	Not Available	57	4		61
13	Silesia	55	31	2		33
14	Warren	Not Available		1		1
15	Alzada	Not Available	7	5		12
16	Baker	1,818	772	179		951
17	Carlyle	20	8	2		10
18	Fort Peck	325	121	11		132
19	Fairview	869	360	49		409
20	Forsyth	2,178	895	139		1,034
21	Frazer	403	101	14		115
22	Glasgow	3,572	1,611	281		1,892
23	Glendive	4,802	2,970	400		3,370
24	Hinsdale	225	113	19		132
25	Ismay	19	10	4		14
26	Malta	2,340	1,040	196		1,236
27	Miles City	8,461	3,867	497		4,364
28	Nashua	375	189	21		210
29	Poplar	881	874	127		1,001
30	Richey	259	117	25		142
31	Rosebud	170	54	7		61
32	Saco	261	48	8		56
33	Savage	300	150	17		167
34	Sidney	5,217	2,227	380		2,607
35	Terry	659	312	67		379
36	St. Marie	Not Available	145	14		159
37	Wibaux	628	216	58		274
38	Whitewater	125	37	8		45
39	Wolf Point	2,880	1,395	212		1,607
40	MT Oil Fields	Not Available	2	5		7
41	**TOTAL Montana Customers**	135,872	61,632	6,907		68,539

1/ 1990 Census.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 30

MONTANA EMPLOYEE COUNTS 1/

Year: 1998

	Department	Year Beginning	Year End	Average
1	Electric	30	26	28
2	Gas	49 (2)	42 (1)	45 (2)
3	Accounting	34	29	32
4	Marketing	2	2	2
5	Management	7	7	7
6	Power	30	27	29
7	Service 2/	51 (1)	55 (5)	53 (3)
13	1/ Parentheses denotes part-time.			
14	2/ Reflects service employees such as meter			
15	readers, service dispatchers and servicemen.			
42	TOTAL Montana Employees	203 (3)	188 (6)	196 (5)

Company Name: **Montana-Dakota Utilities Co.** **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 1999

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000			
2				
3	Electric - Production			
4	Install control system at Lewis & Clark Station	$1,024,542	$246,457	1/
5				
6	Common - Intangible			
7	Work Management System	3,963,256	1,003,504	1/
8				
9				
10				
11				
12	Other Projects<$1,000,000			
13				
14	Electric			
15	Production	$3,201,110	$770,040	1/
16	Transmission:			
17	Integrated	899,031	136,365	1/
18	Direct	401,223	58,506	2/
19	Distribution	5,313,975	927,273	2/
20	General	1,003,790	275,034	2/
21	Common:			
22	General Office	1,882,648	432,559	1/
23	Other Direct	737,358	133,238	2/
24	Total Electric	$13,439,135	$2,733,015	
25				
26	Gas			
27	Distribution	$5,714,422	$1,905,292	2/
28	General	1,339,560	492,183	2/
29	Common:			
30	General Office	1,057,700	311,944	1/
31	Other Direct	356,052	98,148	2/
32	Total Gas	$8,467,734	$2,807,567	
33				
34				
35				
36				
37				
38				
39				
40				
41	TOTAL	$26,894,667	$6,790,543	

1/ Allocated to Montana.
2/ Directly assigned to Montana.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 1998

	Total Company			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
1	January			
2	February			
3	March			
4	April			
5	May			
6	June	NOT APPLICABLE		
7	July			
8	August			
9	September			
10	October			
11	November			
12	December			
13	TOTAL			

	Montana			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
14	January			
15	February			
16	March			
17	April			
18	May			
19	June	NOT APPLICABLE		
20	July			
21	August			
22	September			
23	October			
24	November			
25	December			
26	TOTAL			

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA

Year: 1998

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	11	324,809	7,036,369
2	February	27	210,464	4,754,058
3	March	10	277,411	5,333,083
4	April	7	131,565	2,735,545
5	May	7	82,891	1,857,904
6	June	2	78,757	1,664,490
7	July	20	51,430	1,361,606
8	August	19	56,079	1,475,084
9	September	30	82,300	1,666,409
10	October	29	133,574	3,329,083
11	November	10	195,853	4,770,471
12	December	21	312,662	6,435,618
13	**TOTAL**			42,419,720

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	11	102,374	2,098,368
15	February	26	58,835	1,361,674
16	March	10	88,314	1,542,446
17	April	15	37,127	708,447
18	May	14	24,021	511,404
19	June	3	19,453	419,782
20	July	20	17,723	323,738
21	August	19	18,556	381,353
22	September	30	21,276	424,309
23	October	18	41,738	947,829
24	November	9	56,897	1,352,996
25	December	21	97,250	1,897,788
26	**TOTAL**			11,970,134

Year: 1998

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	1	11	4,660	184,221	9,302	2,697,932	
2	February	21	27	327	88,803	1,718	1,261,700	
3	March	26	10	20,246	142,234	54,893	1,652,385	
4	April	30	7	43,654	27,643	480,192	177,584	
5	May	15	1	71,837	1,589	1,403,457	3,879	
6	June	13	4	95,502	692	1,448,727	1,056	
7	July	15	0	71,182	0	1,852,760	0	
8	August	14	3	66,335	138	1,778,580	630	
9	September	15	30	87,320	88	1,904,125	153	
10	October	9	16	36,441	11,713	518,385	92,733	
11	November	26	10	8,544	66,692	44,629	1,070,393	
12	December	1	21	5,660	185,046	20,096	2,391,077	
13	TOTAL					9,516,864	9,349,522	

		Montana						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
14	January							
15	February							
16	March							
17	April							
18	May							
19	June	NOT AVAILABLE						
20	July							
21	August							
22	September							
23	October							
24	November							
25	December							
26	TOTAL							

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 33

SOURCES OF GAS SUPPLY

Year: 1998

	Name of Supplier 1/	Last Year Volumes Dkt	This Year Volumes Dkt	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	37,136,753	33,530,452	$1.880	$1.761

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 1998

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(Mcf or Dkt)**	Achieved Savings **(Mcf or Dkt)**	Difference
1							
2	NONE						
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**						

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 35

MONTANA CONSUMPTION AND REVENUES

Year: 1998

	Sales of Gas	Operating Revenues		MCF Sold		Avg. No. of Customers 1/	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$27,741,499	$27,928,195	5,573,492	6,337,540	61,443	60,794
2	Firm General	15,630,144	15,946,421	3,272,668	3,749,207	7,366	7,229
3	Small Interruptible	239,952	261,043	59,747	61,141	5	4
4	Large Interruptible						
5							
6							
7							
8							
9							
10							
11	TOTAL	$43,611,595	$44,135,659	8,905,907	10,147,888	68,814	68,027
12							
13							
14							
15		Operating Revenues		BCF Transported		Avg. No. of Customers 1/	
16							
17	Transportation of Gas	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
18							
19	Utilities						
20	Small Interruptible	$437,796	$379,926	0.9	0.8	32	28
21	Large Interruptible	361,944	425,972	2.0	2.3	6	6
22	Firm	11,907	7,782				
23							
24	TOTAL	$811,647	$813,680	2.9	3.1	38	34

1/ Reflects bills divided by twelve.