YEAR ENDING 2012

ANNUAL REPORT
OF

NorthWestern Energy
(Townsend Propane)

GAS UTILITY

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

Propane Annual Report

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Sch. 1	IDENTIFICATION	
	Legal Name of Respondent:	NorthWestern Corporation
	Name Under Which Respondent Does Business:	NorthWestern Energy
	Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
	Person Responsible for Report:	Kendall G. Kliewer
	Telephone Number for Report Inquiries:	(406) 497-2759
	Address for Correspondence Concerning Report:	40 East Broadway Street Butte, MT 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See Northwestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS	
Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Robert Rowe
Vice President, Chief Financial Officer	Tax, Internal Audit, Credit Financial Planning and Analysis Controller and Treasury Functions Investor Relations and Corporate Finance Cash Management and Financial Applications Business Technology Energy Risk Management Flight Services, Executive Compensation	Brian Bird
Vice President, General Counsel	Legal Services Corporate Secretary Records Management Risk Management	Heather Grahame
Vice President, Distribution Operations	Distribution Operations - MT/SD/NE Construction, Engineering, and Planning Organizational Development & Labor Relations Distribution Infrastructure Safety/Health/Environmental Services Support Services	Curt Pohl
Vice President, Transmission	Regional System Planning and Engineering Gas Transmission & Storage Transmission Services Systems Operations Control Center Transmission Business Development and Analysis Organizational Performance & Asset Management	Michael Cashell
Vice President, Supply	Production & Generation Operations Energy Supply Planning, Regulatory, & Marketing Energy Supply Long-Term Resources	John Hines
Vice President, Government & Regulatory Affairs	Government & Regulatory Affairs	Patrick Corcoran
Vice President, Customer Care, Communications & Human Resources	Corporate Communications Account and Analysis Infrastructure Systems and Support Customer Care Key Accounts/Customer Education Human Resources	Bobbi Schroeppel
Chief Audit & Compliance Officer	Internal Audit Enterprise Risk	Michael Nieman
Vice President, Controller	Financial Reporting Accounting Accounts Payable/Payroll Compensation and Benefits	Kendall Kliewer

Reflects active officers as of December 31, 2012.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 110,436**	**112.22%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP) Propane Utility Natural Gas Funding Trust - (Bond Transition Financing) 1/		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		**$ (12,030)**	**-12.22%**
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
NorthWestern Investments, LLC	Holds non-utility assets		
Risk Partners Assurance, Ltd.	Captive insurance company		
Mountain States Transmission Intertie, LLC	Will hold new transmission infrastructure assets		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		**$ 98,406**	**100.00%**

1/ While the Natural Gas Funding Trust (the Trust) is regulated by the MPSC and information pertaining to the Trust is reported to the MPSC on a semi-annual basis, it is reflected on the equity basis in this presentation.

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$32,667,942	84.92%	$5,800,737
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, Human Resources and Print Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	20,055,866	76.52%	6,153,434
Legal Department	Includes the following departments: Chief Legal, Record Services, Risk Mgmt	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	12,266,620	81.98%	2,696,724
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Security, Data Center, Project Management & Asset Control and Capital Related Exp.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	14,663,469	75.08%	4,867,965
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations & Public Affairs.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,798,229	81.67%	852,231
Executive Department	Includes the following departments: CEO, and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	1,967,505	71.86%	770,655
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	765,723	74.00%	269,037
Distribution	Includes the following departments: Sioux Falls Facilities and Mail Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	559,012	74.00%	196,409
TOTAL			$86,744,366	80.06%	$21,607,192

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	**Total Nonutility Subsidiaries**			$0		$0
5	**Total Nonutility Subsidiaries Revenues**			$0		
6						
7						
8						
9	**Utility Subsidiaries**					
10						
11	**Total Utility Subsidiaries**			$0		$0
12	**Total Utility Subsidiaries Revenues**			$2,026,284		
13	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0	-	$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Natural Gas Funding Trust	Metering and billing services	Negotiated Contract Rate	$500,000	95.2%	$500,000
14						
15	**Total Utility Subsidiaries**			$500,000		$500,000
16	**Total Utility Subsidiaries Expenses**			$549,087		
17	**TOTAL AFFILIATE TRANSACTIONS**			$500,000		$500,000

Sch. 8	MONTANA UTILITY INCOME STATEMENT - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 863,090	$ -	$ 863,090	$ 928,549	-7.05%
3						
4	**Total Operating Revenues**	863,090	-	863,090	928,549	-7.05%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	792,062	-	792,062	808,001	-1.97%
9	402 Maintenance Expense	29,055	-	29,055	29,243	-0.64%
10	403 Depreciation Expense	43,367	-	43,367	43,275	0.21%
11	407.3 Regulatory Debits	-	-	-	-	-
12	408.1 Taxes Other Than Income Taxes	59,095	-	59,095	52,822	11.88%
13	409.1 Income Taxes-Federal	(6,580)	-	(6,580)	-	-
14	-Other	(1,361)	-	(1,361)	-	-
15	410.1 Deferred Income Taxes-Dr.	(11,764)	-	(11,764)	1,263	>-300.00%
16	411.1 Deferred Income Taxes-Cr.	-	-	-	-	-
17						
18	**Total Operating Expenses**	903,874	-	903,874	934,604	-3.29%
19	**NET OPERATING INCOME**	$ (40,784)	$ -	$ (40,784)	$ (6,055)	>-300.00%

This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1.

Sch. 9	MONTANA REVENUES - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$ 559,511	$ -	$ 559,511	$ 632,290	-11.51%
5	442 Commercial & Industrial-Small	303,579	-	303,579	296,259	2.47%
6						
7	**Total Sales to Ultimate Consumers**	863,090	-	863,090	928,549	-7.05%
8	447 Sales for Resale					
9						
10	**Total Sales of Propane**	863,090	-	863,090	928,549	-7.05%
11	449.1 Provision for Rate Refunds					
12						
13	**Total Revenue Net of Rate Refunds**	863,090	-	863,090	928,549	-7.05%
14						
15	**Other Operating Revenues**					
16						
17	**Total Other Operating Revenue**	-	-	-	-	-
18	**TOTAL OPERATING REVENUE**	$ 863,090	$ -	$ 863,090	$ 928,549	-7.05%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Supply Expenses**					
2	**Other Propane Supply Expense-Operation**					
3	804 Purchases	$ -	$ -	$ -	$ -	-
4	805 Other Propane Purchases	83,030	-	83,030	(1,649)	>300.00%
5	807 Purchased Propane Expense	-	-	-	-	-
6	808 Propane Withdrawn from Storage	589,279	-	589,279	716,103	-17.71%
7	809 Propane Delivered to Storage	-	-	-	-	-
8	**Total Supply Expenses**	672,309	-	672,309	714,454	-5.90%
9	**Storage Expenses**					
10	**Other Storage-Operation**					
11	840 Operation Supervision & Engineering	-	-	-	-	-
12	841 Operation Labor & Expenses	-	-	-	-	-
13	842 Rents	13,251	-	13,251	15,393	-13.92%
14	**Total Operation-Other Storage**	13,251	-	13,251	15,393	-13.92%
15						
16	**Other Storage-Maintenance**					
17	847 Maintenance Storage Expenses	-	-	-	-	-
18	**Total Maintenance-Other Storage**	-	-	-	-	-
19	**Total Storage Expenses**	13,251	-	13,251	15,393	-13.92%
20	**Distribution Expenses**					
21	**Distribution-Operation**					
22	870 Supervision & Engineering	-	-	-	-	-
23	874 Mains & Service	15,384	-	15,384	12,331	24.76%
24	878 Meter & House Regulators	43,614	-	43,614	22,475	94.06%
25	879 Customer Installation	6,411	-	6,411	5,451	17.59%
26	880 Other	2,020	-	2,020	1,573	28.47%
27	**Total Operation-Distribution**	67,429	-	67,429	41,830	61.20%
28	**Distribution-Maintenance**					
29	885 Maintenance Superv. & Eng.	-	-	-	-	-
30	887 Maintenance of Mains	26,927	-	26,927	27,793	-3.12%
31	892 Maint. of Services	229	-	229	135	69.72%
32	893 Maint. of Meters & House Regulators	1,152	-	1,152	1,311	-12.12%
33	894 Maintenance of Other Equipment	747	-	747	3	>300.00%
34	**Total Maintenance-Distribution**	29,055	-	29,055	29,242	-0.64%
35	**Total Distribution Expenses**	96,484	-	96,484	71,072	35.76%
36						
37	**Customer Accounts Expenses**					
38	**Customer Accounts-Operation**					
39	901 Supervision	-	-	-	-	-
40	902 Meter Reading	1,225	-	1,225	1,260	-2.81%
41	903 Customer Records & Collection Expense	442	-	442	365	21.19%
42	**Total Customer Accounts Expenses**	1,667	-	1,667	1,625	2.58%
43	**Administrative & General Expenses**					
44	**Admin. & General - Operation**					
45	920 Salaries	648	-	648	660	-1.85%
46	921 Office Supplies & Expenses	9	-	9	244	-96.12%
47	923 Outside Services	36,749	-	36,749	33,794	8.74%
48	925 Injuries & Damages	-	-	-	-	-
49	926 Employee Pensions and Benefits	-	-	-	-	-
50	928 Regulatory Commission Expense	-	-	-	-	-
51	**Total Operation-Admin. & General**	37,406	-	37,406	34,698	7.81%
52	**Admin. & General - Maintenance**					
53	935 General Plant	-	-	-	-	-
54	**Total Admin. & General Expenses**	37,406	-	37,406	34,698	7.81%
55						
56	**TOTAL OPER. & MAINT. EXPENSES**	$ 821,117	$ -	$ 821,117	$ 837,242	-1.93%

Sch. 11	MONTANA TAXES OTHER THAN INCOME - PROPANE			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,895	$1,861	1.84%
3	Real Estate & Personal Property	55,116	48,732	13.10%
4	Consumer Counsel	259	279	-7.19%
5	Public Service Commission	1,812	1,950	-7.05%
6	Vehicle Use Tax	12	-	-
7				
8	**TOTAL TAXES OTHER THAN INCOME**	$59,095	$52,822	11.88%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	ACUREN INSPECTION INC	Materials Engineering & Testing	79,457.64
2	AEVENIA INC	Construction	1,115,362.98
3	ALSTOM GRID INC	Software Support Services	1,380,830.90
4	AMERICAN ARBITRATION ASSOCIATION	Arbitration Services	78,789.49
5	APPALACHIAN PIPELINE CONTRACTO	Pipeline Contractor	2,485,064.68
6	ARCADIS US INC	Engineering Services	751,691.19
7	ASPLUNDH TREE EXPERT CO	Tree Trimming	3,540,086.89
8	ASSOCIATED ARBORISTS	Vegetation Management	1,523,260.82
9	AUTOMOTIVE RENTALS INC	Fleet Management	8,189,852.69
10	AVERY PIPELINE SERVICES INC	Welding Inspectors	146,697.73
11	B & B CONTRACTING INC	Construction	427,759.92
12	BALHOFF & WILLIAMS LLC	Legal Services	284,819.67
13	BART ENGINEERING COMPANY	Engineering Services	271,835.44
14	BENEDICT CONSULTING PLLC	Energy Management System Consulting	137,000.00
15	BIG SKY WATER HAULING LLC	Water Hauling Services	87,131.80
16	BILL FIELD TRUCKING INC	Hauling Services	354,759.26
17	BROWNING, KALECZYC, BERRY & HOVEN	Legal Services	621,301.42
18	CAUTHEN FORBES & WILLIAMS	Governmental Affairs Consultant	120,000.00
19	CENTRAL AIR SERVICE INC	Aerial Pilot Services	172,767.50
20	CENTRAL COPTERS INC	Flight Services	83,946.28
21	CENTRON SERVICES INC	Collection Services	80,739.67
22	CESSNA AIRCRAFT COMPANY	Aircraft Maintenance	307,420.42
23	CHARLES RIVER ASSOCIATES	Expert Witness	81,112.34
24	COMPLETE CAREER CENTER INC	Temporary Employment Services	99,223.55
25	CONTINENTAL STEEL WORKS	Fabrication Services	518,454.76
26	COP CONSTRUCTION LLC	Construction	783,846.10
27	CRIST KROGH & NORD LLC	Legal Services	119,534.08
28	CROWLEY FLECK	Legal Services	477,507.07
29	CYME INTERNATIONAL T & D INC	Construction	111,866.72
30	DAHME CONSTRUCTION CO INC	Construction	383,937.27
31	DAKOTA HIGH VOLTAGE TESTING	Electric System Testing and Maintenance	285,314.91
32	DAVEY RESOURCE GROUP	Field Surveyors	3,100,767.43
33	DAVEY TREE SURGERY COMPANY	Tree Trimming	1,495,705.82
34	DELOITTE & TOUCHE LLP	Audit Services	1,304,364.40
35	DELOITTE TAX LLP	Tax Consultants	237,112.36
36	DEPT OF HEALTH & HUMAN SERVICES	Weatherization Program Services	2,023,536.62
37	DEWILD GRANT RECKERT & ASSOCIATES	Engineering Services	470,482.86
38	DICKSTEIN SHAPIRO LLP	Legal Services	137,917.91
39	DIGITAL INSPECTIONS - A KEMA COMPANY	Software Support Services	99,288.44
40	DISTRIBUTION CONSTRUCTION CO	Gas Pipeline Construction	1,366,639.59
41	DJ&A P C CONSULTING ENGINEERS	Engineering Services	78,721.96
42	DNV RENEWABLES (USA) INC	Renewable Energy Consultants	370,664.70
43	DORSEY & WHITNEY LLP	Legal Services	180,306.28
44	ECOVA INC	Energy Conservation Consultants	169,516.00
45	EDM INTERNATIONAL INC	Anchor Rod Inspection Services	669,107.35
46	EIDEBAILLY	Audit Services	76,787.50
47	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	2,245,929.10
48	ENERGY RESOURCE MANAGEMENT INC	Energy Conservation Consultants	193,293.00
49	ENERGY SHARE OF MONTANA	USBC Services	705,506.25
50	EXPRESS SERVICES INC	Temporary Employment Services	106,872.56
51	FAIRBANKS MORSE ENGINE	Construction	848,453.85
52	FALLS CONSTRUCTION COMPANY	Construction	240,297.68
53	FINANCIAL ACCOUNTING INSTITUTE	Finance and Accounting Training	105,007.26
54	FISHNET SECURITY INC	Software Support Services	657,763.07
55	FOSTER ASSOCIATES INC	Depreciation Study Consultants	215,877.62
56	GARTNER INC	Information Technology Consulting	124,400.00
57	GARY INCE CONSTRUCTION INC	Construction	86,826.00
58	GD & J INC	Well and Compressor Maintenance	110,379.14
59	GE ELECTRIC INTERNATIONAL INC	Energy Consulting Services	225,000.00
60	GREATER GALLATIN CONTRACTORS	Landscape Repair Services	91,540.49
61	H & H ASPHALT & MAINTENANCE INC	Asphalt Services	120,169.29
62	H & H CONTRACTING INC	Concrete and Asphalt Services	481,671.07
63	HAIDER CONSTRUCTION INC	Backhoe Services	355,503.49
64	HAROLD K SCHOLZ CO	Construction	134,290.91

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
65	HDR ENGINEERING INC	Engineering Services	928,013.97
66	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	350,108.25
67	HEATH CONSULTANTS INC	Gas Leak Surveys	442,780.31
68	HIGH MARK MEDIA	Marketing Services	86,230.00
69	HUFF CONSTRUCTION INC	Construction	967,689.32
70	INDEPENDENT INSPECTION COMPANY	Electric Line Inspection	2,930,468.58
71	INDEPENDENT POWER SYSTEMS INC	Installation of Renewable Energy Systems	358,893.88
72	INTELLIGENT ACCESS SYSTEMS OF	Access System Installation	144,190.31
73	INTERGRAPH CORPORATION	Software Consultants	732,136.59
74	JACOBSEN TREE EXPERTS	Tree Trimming	1,048,102.07
75	JAMES TALCOTT CONSTRUCTION INC	Construction	137,500.00
76	JERKE CONSTRUCTION CO	Construction	98,294.36
77	JONES DAY	Legal Services	220,006.01
78	JSSI JET SUPPORT SERVICES INC	Flight Services	193,771.88
79	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	157,738.52
80	KELLY SERVICES INC	Engineering Services	101,496.15
81	KEMA SERVICES INC	USB and DSM Programs and Services	7,909,983.35
82	KM CONSTRUCTION CO INC	Construction	94,056.73
83	KNIFE RIVER	Construction	79,172.86
84	LANDS ENERGY CONSULTING	Energy Consultants	133,716.47
85	LARSON DIGGING INC	Construction	139,324.02
86	LC STAFFING SERVICE	Temporary Employment Services	83,360.65
87	LEONARD,STREET & DEINARD	Legal Services	165,390.78
88	LOCKMER PLUMBING HEATING & UTILITIES INC	Gas Meter Relocations	150,538.06
89	MAPPCOR	Electric Reliability Services	358,335.80
90	MARKOVICH CONSTRUCTION & REAL ESTATE	Construction	96,707.00
91	MARTIN EXCAVATING LLC	Excavation Contractor	97,653.75
92	MECHANICAL TECHNOLOGY INC	Construction	147,831.10
93	MERCER HUMAN RESOURCE CONSULTING	Actuarial and Consulting Services	91,369.00
94	MERIDIAN IT INC	Information Technology Services	288,087.25
95	MICROSOFT LICENSING GP	Computer Licensing	704,156.83
96	MICROSOFT SERVICES	Computer Maintenance	92,468.04
97	MOODY'S INVESTORS SERVICE	Debt Rating Services	186,200.00
98	MOUNTAIN POWER CONSTRUCTION CO	Construction	1,626,464.11
99	MOUNTAIN WEST HOLDING COMPANY	Construction	157,164.00
100	MUTH ELECTRIC INC	Electric Construction	94,103.06
101	NATIONAL CENTER FOR APPROPRIATE TECHNOLOGY	Conservation Program Consultants	1,314,638.62
102	NATURAL GAS SERVICES INC	Gas Servicemen	85,361.30
103	NEWMECH COMPANIES INC	Construction	664,687.00
104	NORLEY CONSULTING	Gas Compressor Consultant	119,021.17
105	NORTHWEST DYNAMICS INSPECTION	Safety Inspections	75,039.00
106	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,458,548.38
107	NORTHWEST TOWER	Construction	215,800.00
108	NOVINIUM INC	Construction	117,704.25
109	OLSON CONSTRUCTION	Construction	132,662.57
110	OLSON LAND SERVICES	Real Estate Services	80,808.97
111	OMIMEX CANADA LTD	Gas Lease Operating Expenses	85,712.87
112	OPEN ACCESS TECHNOLOGY INT'L I	Software Support Services	293,028.58
113	OSMOSE INC	Construction	606,640.30
114	P2 ENERGY SOLUTIONS INC	Computer System Implementation	80,617.60
115	PACER ENERGY LLC	Due Diligence for Gas Acquisition	300,380.43
116	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	6,716,514.67
117	PARISI WESTERN PLBG & HTNG,INC	Construction	85,703.16
118	PATTON BOGGS LLC	Legal Services	103,182.51
119	PAULSEN MARKETING	Advertising	994,814.18
120	PERKINS COIE	Legal Services	2,293,884.53
121	PORTLAND ENERGY CONSERVATION INC	Energy Conservation Consultants	160,370.00
122	POWER ENGINEERS INCORPORATED	Engineering Services	1,777,705.08
123	POWERPLAN INC	Software Implementation Support Services	438,819.92
124	PRAIRIE POTHOLE CONSULTING	Land Survey Services	94,858.75
125	PRATT & WHITNEY POWER SYSTEMS	Construction	16,837,317.74
126	PRICEWATERHOUSECOOPERS LLP	Software Implementation Support Services	159,357.62
127	PRO PIPE CORPORATION	Construction	79,287.40
128	Q3 CONTRACTING INC	Construction	260,714.43
129	RINGGENBERG ELECTRIC INC	Construction	104,185.26

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	RML INCORPORATED	Boring Services	290,629.90
131	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	19,140,260.56
132	ROD TABBERT CONSTRUCTION INC	Construction	619,789.72
133	ROUNDS BROTHERS TRENCHING	Boring Services	353,946.07
134	RYAN COMPANIES US INC	Substation Design	76,793.09
135	S & C ELECTRIC COMPANY	Construction	152,917.28
136	SAP INDUSTRIES INC	Software Support Services	723,160.39
137	SBW CONSULTING INCORPORATED	DSM Program Evaluation	1,885,577.18
138	SCENIC CITY PUMPING	Construction	125,688.57
139	SHUMAKER TRUCKING & EXCAVATING	Excavation Contractor	97,900.75
140	SIDLEY AUSTIN LLP	Legal Services	92,378.63
141	SKADDEN, ARPS, SLATE, MEAGHER	Legal Services	720,619.60
142	SOLAR PLEXUS	USB and DSM Programs and Services	103,705.00
143	SPHERION CORPORATION	Temporary Employment Services	322,750.94
144	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	125,055.00
145	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	386,820.15
146	STEAMWAY CLEANING & RESTORATION	Water Extraction Services	94,126.14
147	STENSON MANAGEMENT CONSULTING	Effective Leadership Consultant	81,636.69
148	STINSON MORRISON LLP	Legal Services	253,239.27
149	STONE & WEBSTER INC	Power Generation Development	1,974,726.40
150	SULLIVAN, TABARACCI & RHOADES, PC	Legal Services	152,552.29
151	SUNDANCE SOLAR SYSTEMS	Solar System Installation	116,540.00
152	TERRACON	Engineering Services	189,019.67
153	THE BOLDT COMPANY	Power Plant Construction	7,706,074.02
154	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	336,095.70
155	THE ENERGY AUTHORITY INC	Scheduling and Dispatching	315,422.00
156	THE L E MYERS CO	Storm Damage Restoration	2,969,657.02
157	TODD BRUESKE CONSTRUCTION	Construction	246,277.69
158	TONY LASLOVICH CONSTRUCTION	Construction	166,767.50
159	TOWER SYSTEMS INC	Construction	326,176.70
160	TRADEMARK ELECTRIC INC	Construction	505,803.35
161	UTILITIES PLUS ENERGY SERVICES	Construction	130,460.19
162	UTILITIES UNDERGROUND LOCATION CENTER	Locating Services and Excavation Notifications	123,452.80
163	VAN NESS FELDMAN	Legal Services	108,703.70
164	VARSITY CONTRACTORS INC	Janitorial Services	301,043.55
165	VERTEX	Billing Services	4,382,121.41
166	WASHINGTON FORESTRY CONSULTANTS	Forestry Consultants	443,012.40
167	WATER & ENVIRONMENTAL TECHNOLOGIES	Environmental Engineering Services	171,158.88
168	WILLIAMSON FENCING & SPR.,INC.	Construction	179,594.61
169	WINSTON & STRAWN LLP	Legal Services	963,430.70
170	WIT PIPELINE INSPECTION	Pipeline Inspection Services	81,521.00
171	WOOD GROUP POWER PLANT SERVICE	Construction	454,890.92
172	ZACHA UNDERGROUND CONSTRUCTION	Construction	77,653.45
173			
174			
175			
176			
177	**Total of Payments Set Forth Above**		$ 149,331,093

1/ This schedule includes payments for professional services over $75,000.

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
	There are three employee political action committees (PAC)s: a. Employees of NorthWestern Corporation (NorthWestern Energy) PAC; b. NorthWestern Energy Employees PAC; and c. NorthWestern Public Service Employees PAC. All of the money contributed by members is dedicated to support political candidates. No company funds may be spent in support of a political candidate. Nominal administrative costs for such things as duplicating, postage, and meeting expenses are paid by the company as provided by law. These costs are charged to shareholder expense.			
	TOTAL Contributions	$ -	$ -	

Sch. 14	Pension Costs 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ____________		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 477,929,697	$ 421,133,381	13.49%
8	Service cost	10,435,096	9,187,089	13.58%
9	Interest cost	21,372,539	21,718,105	-1.59%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	54,198,276	43,905,803	23.44%
13	Acquisition	-	-	-
14	Benefits paid	(18,101,682)	(18,014,681)	-0.48%
15	Benefit obligation at end of year	$ 545,833,926	$ 477,929,697	14.21%
16	**Change in Plan Assets**	-	-	
17	Fair value of plan assets at beginning of year	$ 383,101,559	$ 377,834,016	1.39%
18	Actual return on plan assets	43,755,885	12,782,224	242.32%
19	Acquisition	-	-	-
20	Employer contribution	10,500,000	10,500,000	
21	Plan participants' contributions	-	-	-
22	Benefits paid	(18,101,682)	(18,014,681)	-0.48%
23	Fair value of plan assets at end of year	$ 419,255,762	$ 383,101,559	9.44%
24	**Funded Status**	$ (126,578,164)	$ (94,828,138)	-33.48%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (126,578,164)	$ (94,828,138)	-33.48%
30	**Weighted-average Assumptions as of Year End**	-	-	
31	Discount rate	3.80%	4.55%	-16.48%
32	Expected return on plan assets	7.00%	7.25%	-3.45%
33	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 10,435,096	$ 9,187,089	13.58%
36	Interest cost	21,372,539	21,718,105	-1.59%
37	Expected return on plan assets	(26,637,374)	(26,958,867)	1.19%
38	Amortization of prior service cost	246,361	246,361	
39	Recognized net actuarial gain	8,314,967	2,515,966	230.49%
40	Net periodic benefit cost (SEC Basis)	$ 13,731,589	$ 6,708,654	104.68%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**	-	-	
42	Pension Costs	$ 29,410,000	$ 29,410,000	
43	Pension Costs Capitalized	6,292,692	6,021,422	4.51%
44	Accumulated Pension Asset (Liability) at Year End	$ (126,578,164)	$ (94,828,138)	-33.48%
45	**Number of Company Employees:**			
46	Covered by the Plan	3,100	3,149	-1.56%
47	Not Covered by the Plan 2/	268	213	25.82%
48	Active	947	972	-2.57%
49	Retired	1,359	1,358	0.07%
50	Deferred Vested Terminated	794	819	-3.05%

1/ NorthWestern Corporation has a separate pension plan covering South Dakota and Nebraska employees that is not reflected above.
2/This plan was closed to new entrants effective 10/03/08.

Sch. 14a	Pension Costs			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions	Not Applicable		
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 218,194,855	$ 220,342,829	0.98%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 7,164,928	$ 6,720,175	6.62%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 253,146,989	$ 218,194,855	16.02%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 4,973,279	$ 4,598,308	8.15%
44	401(k) Plan Defined Contribution Costs Capitalized	1,064,105	941,461	13.03%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,418	1,388	2.16%
48	Not Covered by the Plan			
49	Active - Participating	1,382	1,347	2.60%
50	Retired			
51	Vested Former Employees, Retirees and Active-	237	259	-8.49%
52	Noncontributing			

2/ This plan covers all NorthWestern Corporation employees.

3/ Represents total company 401(k) plan participants.

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2009.9.129			
4	Order number: 7046h			
5	Amount recovered through rates	$418,239	$350,602	19.29%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	2.80%	3.75%	-25.33%
8	Expected return on plan assets	7.00%	7.25%	-3.45%
9	Medical Cost Inflation Rate 3/	8.50%,4.5%:16	8.75%,4.5%:17	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	**Describe any Changes to the Benefit Plan:**			
16				

1/ Obtained from NorthWestern Energy-Montana's 2012 FASB 106 Valuation. Assumptions and data are as of December 31, 2012.

2/ Obtained from NorthWestern Energy-Montana's 2011 FASB 106 Valuation. Assumptions and data are as of December 31, 2011.

3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Other Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$22,420,683	$26,467,645	-15.29%
10	Service cost	441,640	358,150	23.31%
11	Interest Cost	817,698	970,483	-15.74%
12	Plan participants' contributions	957,107	1,089,753	-12.17%
13	Amendments	-	(464,242)	100.00%
14	Actuarial loss/(gain)	998,382	(2,711,685)	136.82%
15	Acquisition	-	-	-
16	Benefits paid	(2,453,687)	(3,289,421)	25.41%
17	Benefit obligation at end of year	$23,181,823	$22,420,683	3.39%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$15,502,279	$17,201,034	-9.88%
20	Actual return on plan assets	1,789,246	339,995	>300.00%
21	Acquisition	-	-	-
22	Employer contribution	98,461	160,918	-38.81%
23	Plan participants' contributions	957,107	-	-
24	Benefits paid	(2,453,687)	(2,199,668)	-11.55%
25	Fair value of plan assets at end of year	$15,893,406	$15,502,279	2.52%
26	**Funded Status**	($7,288,417)	($6,918,404)	-5.35%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($7,288,417)	($6,918,404)	-5.35%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$441,640	$358,150	23.31%
33	Interest cost	817,698	970,483	-15.74%
34	Expected return on plan assets	(1,020,701)	(1,185,450)	13.90%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,148,915)	($2,148,915)	
37	Recognized net actuarial loss/(gain)	767,193	657,715	16.65%
38	Net periodic benefit cost	($1,143,085)	($1,348,017)	15.20%
39	**Accumulated Post Retirement Benefit Obligation**		-	
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	98,461	160,918	-38.81%
43	TOTAL	$98,461	$160,918	-38.81%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	418,239	350,602	19.29%
47	TOTAL	$418,239	$350,602	19.29%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$418,239	$350,602	19.29%
50	Pension Costs Capitalized	89,488	71,782	24.67%
51	Accumulated Pension Asset (Liability) at Year End	(7,288,417)	(6,918,404)	-5.35%
52	**Number of Montana Employees:**		-	
53	Covered by the Plan	2,011	2,085	-3.55%
54	Not Covered by the Plan	172	192	-10.42%
55	Active	971	1,014	-4.24%
56	Retired	933	961	-2.91%
57	Spouses/Dependants covered by the Plan	107	110	-2.73%

4/ There is approximately an additional $10,858,097 and $10,006,342 in other company OPEBS liabilities outstanding at December 31, 2012 and 2011, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

Note: This schedule includes the ten most highly compensated employees assigned or allocated to Montana that are not already included on Sch 17.

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	204,756	60,674 A	16,929 B 62,961 C 155,470 D	500,790	472,327	6%
2	Michael R. Cashell Vice President, Transmission	189,056	56,022 A	27,479 B 58,152 C 160,575 D	491,284	409,315	20%
3	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	220,217	65,503 A	41,597 B 67,902 C 33,496 D	428,715	389,402	10%
4	John D. Hines Vice President, Supply	189,056	56,022 A	15,548 B 58,152 C 65,110 D	383,888	326,832	17%
5	William T. Rhoads General Manager, Generation	162,244	33,850 A	20,907 B 22,481 C 119,631 D 5,433 E 74 F	364,620	352,977	3%
6	Michael L. Nieman Chief Audit and Compliance Officer	194,076	46,954 A	43,490 B 35,101 C 38,116 D 3,882 G	361,619	323,025	12%
7	Daniel L. Rausch Treasurer	172,320	36,790 A	37,057 B 24,324 C 26,341 D 5,771 E	302,603	271,486	11%
8	John S. Fitzpatrick Executive Director State/Local Community Relations	174,891	22,031 A	21,161 B 18,552 C 64,893 D	301,528	300,941	0%
9	Wayne M. Hitt Director, Tax	157,842	31,201 A	35,016 B 22,309 C 9,722 D 7,627 H	263,717	257,414	2%
10	Jeanne M. Barnett Vold Business Technology Officer	157,516	32,200 A	20,913 B 22,309 C 17,883 D	250,821	N/A	

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2012 Employee Incentive Compensation Plan. Amounts were earned in 2012 and paid in the first quarter of 2013. Based on company performance against plan, the incentive plan was funded at 98% of target. Individual awards varied from the funded level based on individual performance.

2/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, Health Savings Account, non-cash awards and related tax liability gross up, 401(k) match and non-elective 401(k) contribution.

C> Values reflect the grant date fair value for restricted stock awards.

D>Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2012.

E> Vacation sold back during the year.

F> Noncash taxable award and gross-up taxes on award.

G> Merit cash payment.

H> Imputed income related to commuting.

SCHEDULE 17

Note: This schedule contains the five most highly compensated corporate officers who are assigned or allocated to Montana.

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Robert C. Rowe President & Chief Executive Officer	525,013	414,864 A	19,364 B 476,307 C 63,143 D	1,498,691	1,468,711	2%
2	Brian B. Bird Vice President & Chief Financial Officer	344,417	170,098 A	41,006 B 217,210 C 29,744 D 1,274 E	803,749	771,131	4%
3	Heather H. Grahame Vice President & General Counsel	313,412	123,828 A	44,095 B 147,022 C 0 D	628,357	624,897	1%
4	Curtis T. Pohl Vice President, Retail Operations	246,757	97,493 A	40,089 B 115,747 C 62,888 D	562,974	509,158	11%
5	Kendall Kliewer Vice President & Controller	228,528	67,456 A	39,872 B 70,860 C 33,335 D	440,051	342,528	28%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the 2012 Employee Incentive Compensation Plan. Amounts were earned in 2012 and paid in the first quarter of 2013. Based on company performance against plan, the incentive plan was funded at 98% of target.

2/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, Health Savings Account, 401(k) match, and non-elective 401(k) contribution.

C> Values reflect the grant date fair value for restricted stock awards.

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2012.

E> Imputed income recorded for amount exceeding the maximum contribution to the company's Employee Stock Purchase Plan.

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$ 3,723,508,020	$ 3,479,352,079	$ 244,155,941	7.02%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	105 Plant Held for Future Use	4,900	4,900	-	0.00%
6	107 Construction Work in Progress	115,303,982	72,580,805	$42,723,177	58.86%
7	108 Accumulated Depreciation Reserve	(1,557,915,890)	(1,481,407,150)	($76,508,740)	5.16%
8	108.1 Accumulated Depreciation - Capital Leases	(13,068,062)	(11,057,582)	($2,010,480)	18.18%
9	111 Accumulated Amortization & Depletion Reserves	(27,265,816)	(23,574,461)	($3,691,355)	15.66%
10	114 Electric Plant Acquisition Adjustments	-	-	-	-
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	-	-	-	-
12	116 Utility Plant Adjustments	355,128,500	355,128,500	-	0.00%
13	117 Gas Stored Underground-Noncurrent	32,116,873	32,119,408	(2,535)	-0.01%
14	**Total Utility Plant**	2,668,022,044	2,463,356,036	204,666,008	8.31%
15	**Other Property and Investments**				
16	121 Nonutility Property	9,971,371	9,974,240	(2,869)	-0.03%
17	122 Accumulated Depr. & Amort.-Nonutility Property	(625,930)	(503,814)	(122,116)	24.24%
18	123.1 Investments in Assoc Companies and Subsidiaries	(160,632,859)	(152,003,379)	(8,629,480)	5.68%
19	124 Other Investments	10,956,526	8,556,077	2,400,449	28.06%
20	128 Miscellaneous Special Funds	-	-	-	-
21	LT Portion of Derivative Assets - Hedges	-	-	-	-
22	**Total Other Property & Investments**	(140,330,892)	(133,976,876)	(6,354,016)	4.74%
23	**Current and Accrued Assets**				
24	131 Cash	9,783,614	5,888,517	3,895,097	66.15%
25	134 Other Special Deposits	2,920,144	3,998,525	(1,078,381)	-26.97%
26	135 Working Funds	38,500	39,300	(800)	-2.04%
27	136 Temporary Cash Investments	-	-	-	-
28	141 Notes Receivable	-	-	-	-
29	142 Customer Accounts Receivable	68,107,331	71,822,880	(3,715,549)	-5.17%
30	143 Other Accounts Receivable	7,314,152	8,031,487	(717,335)	-8.93%
31	144 Accumulated Provision for Uncollectible Accounts	(3,237,838)	(2,929,624)	(308,214)	10.52%
32	145 Notes Receivable-Associated Companies	-	-	-	-
33	146 Accounts Receivable-Associated Companies	2,043,636	4,851,585	(2,807,949)	-57.88%
34	151 Fuel Stock	8,385,009	7,281,127	1,103,882	15.16%
35	154 Plant Materials and Operating Supplies	25,514,876	22,407,788	3,107,088	13.87%
36	164 Gas Stored - Current	20,240,870	29,819,575	(9,578,705)	-32.12%
37	165 Prepayments	10,863,608	8,675,982	2,187,626	25.21%
38	171 Interest and Dividends Receivable	-	-	-	-
40	172 Rents Receivable	108,165	76,604	31,561	41.20%
41	173 Accrued Utility Revenues	71,442,599	71,118,239	324,360	0.46%
42	174 Miscellaneous Current & Accrued Assets	164,316	350,081	(185,765)	-53.06%
43	175 Derivative Instrument Assets (175)	-	-	-	100.00%
44	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-	-
45	176 LT Portion of Derivative Assets - Hedges	-	-	-	-
46	(less) LT Portion of Derivative Assets - Hedges	-	-	-	-
47	**Total Current & Accrued Assets**	223,688,982	231,432,066	(7,743,084)	-3.35%
48	**Deferred Debits**				
49	181 Unamortized Debt Expense	10,716,719	11,307,102	(590,383)	-5.22%
50	182 Regulatory Assets	382,486,507	329,875,457	52,611,050	15.95%
51	183 Preliminary Survey and Investigation Charges	1,162,190	825,634	336,556	40.76%
52	184 Clearing Accounts	12,306	13,354	(1,048)	-7.85%
53	185 Temporary Facilities	-	-	-	-
54	186 Miscellaneous Deferred Debits	1,353,494	1,883,035	(529,541)	-28.12%
55	189 Unamortized Loss on Reacquired Debt	13,944,342	15,413,238	(1,468,896)	-9.53%
56	190 Accumulated Deferred Income Taxes	148,027,620	164,228,720	(16,201,100)	-9.86%
57	191 Unrecovered Purchased Gas Costs	6,285,942	3,554,323	2,731,619	76.85%
58	**Total Deferred Debits**	563,989,120	527,100,863	36,888,257	7.00%
59	**TOTAL ASSETS and OTHER DEBITS**	$ 3,315,369,254	$ 3,087,912,089	$ 227,457,165	7.37%

Sch. 18	cont.	BALANCE SHEET 1/			
	Account Title	This Year	This Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 407,917	$ 398,411	$ 9,506	2.39%
4	204 Preferred Stock Issued	-	-	-	-
5	207 Premium on Capital Stock	-	-	-	-
6	211 Miscellaneous Paid-In Capital	849,218,725	816,700,362	32,518,363	3.98%
7	213 Discount on Capital Stock	-	-	-	-
8	214 Capital Stock Expense	-	-	-	-
9	215 Appropriated Retained Earnings	-	-	-	-
10	216 Unappropriated Retained Earnings	172,791,546	128,631,093	44,160,453	34.33%
12	217 Reacquired Capital Stock	(90,702,563)	(90,272,890)	(429,673)	0.48%
13	219 Accumulated Other Comprehensive Income	2,316,682	3,655,967	(1,339,285)	-36.63%
14	**Total Proprietary Capital**	934,032,307	859,112,943	74,919,364	8.72%
15	**Long Term Debt**				
16	221 Bonds	1,055,205,000	905,205,000	150,000,000	16.57%
17	223 Advances in Associated Companies	-	-	-	-
18	224 Other Long Term Debt	-	-	-	-
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	131,638	155,738	(24,100)	-15.47%
20	**Total Long Term Debt**	1,055,073,362	905,049,262	150,024,100	16.58%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	31,562,420	32,917,879	(1,355,459)	-4.12%
23	228.1 Accumulated Provision for Property Insurance	-	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	11,081,906	10,003,210	1,078,696	10.78%
25	228.3 Accumulated Provision for Pensions and Benefits	23,984,164	26,150,621	(2,166,457)	-8.28%
26	228.4 Accumulated Miscellaneous Operating Provisions	166,841,275	214,313,846	(47,472,571)	-22.15%
27	229 Accumulated Provision for Rate Refunds	24,618,109	11,432,481	13,185,628	115.33%
28	230 Asset Retirement Obligations	9,230,322	6,291,623	2,938,699	46.71%
29	**Total Other Noncurrent Liabilities**	267,318,196	301,109,660	(33,791,464)	-11.22%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	122,933,903	166,933,493	(43,999,590)	-26.36%
32	232 Accounts Payable	87,258,806	80,813,254	6,445,552	7.98%
33	233 Notes Payable to Associated Companies	-	-	-	-
34	234 Accounts Payable to Associated Companies	-	70,978	(70,978)	-100.00%
35	235 Customer Deposits	12,502,752	13,088,340	(585,588)	-4.47%
36	236 Taxes Accrued	32,161,732	33,058,019	(896,287)	-2.71%
37	237 Interest Accrued	17,876,133	15,318,941	2,557,192	16.69%
39	238 Dividends Declared	-	-	-	-
40	241 Tax Collections Payable	1,167,397	1,198,760	(31,363)	-2.62%
41	242 Miscellaneous Current and Accrued Liabilities	56,059,420	47,775,316	8,284,104	17.34%
42	243 Obligations Under Capital Leases-Current	1,611,617	1,370,168	241,449	17.62%
43	244 Derivative Instrument Liabilities	5,428,321	20,312,243	(14,883,922)	-73.28%
44	245 Derivative Instrument Liabilities - Hedges	-	-	-	-
45	**Total Current and Accrued Liabilities**	337,000,081	379,939,512	(42,939,431)	-11.30%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	34,680,992	41,020,091	(6,339,099)	-15.45%
48	253 Other Deferred Credits	176,005,656	137,947,782	38,057,874	27.59%
49	254 Regulatory Liabilities	27,572,155	28,352,270	(780,115)	-2.75%
50	255 Accumulated Deferred Investment Tax Credits	1,196,810	1,572,445	(375,635)	-23.89%
51	257 Unamortized Gain on Reacquired Debt	-	-	-	-
52	281-283 Accumulated Deferred Income Taxes	482,489,695	433,808,124	48,681,571	11.22%
53	**Total Deferred Credits**	721,945,308	642,700,712	79,244,596	12.33%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 3,315,369,254	$ 3,087,912,089	$ 227,457,165	7.37%
55					

56 1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory
57 Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the
58 equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian
59 Montana Pipeline Corp.
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NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 673,200 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. Events occurring subsequent to December 31, 2012, have been evaluated as to their potential impact to the Financial Statements through the date of issuance.

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Accounting Standards Codification (ASC) 810 "Consolidation". ASC 810 requires that all majority-owned subsidiaries be consolidated (see Note 4). The other significant differences consist of the following:

- Earnings per share is not presented;
- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $264.5 million and $251.2 million as of December 31, 2012 and December 31, 2011, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 7);
- Goodwill is reflected in the Balance Sheets as a utility plant adjustment of $355.1 million as of December 31, 2012 and December 31, 2011, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 8);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $147.6 million for December 31, 2012 and December 31, 2011, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;
- The current portion of gas stored underground is reflected in the Balance Sheets as current and accrued assets, as compared to inventory for GAAP purposes;
- Current and long-term debt is classified in the Balance Sheets as all long-term debt in accordance with regulatory treatment, while current and long-term debt are separately presented for GAAP reporting;

- Accumulated deferred tax assets and liabilities are classified in the Balance Sheets as gross non-current deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred tax asset or liability separately classified as current or non-current; and

- Regulatory assets and liabilities are reflected in the Balance Sheets as non-current items, while current and non-current amounts are separately presented for GAAP.

Use of Estimates

The preparation of financial statements in conformity with the regulatory basis of accounting requires us 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 long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, uncollectible accounts, our QF obligation, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $3.2 million and $2.9 million at December 31, 2012 and December 31, 2011, respectively. Unbilled revenues were $71.4 million and $71.1 million at December 31, 2012 and December 31, 2011, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31, 2012	December 31, 2011
Fuel stock	$ 8,385	$ 7,281
Materials and supplies	25,515	22,408
Gas stored underground (including the non-current portion reflected in utility plant)	52,358	61,939
	$ 86,258	$ 91,628

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, *Regulated Operations* (ASC 980). Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Statement of Income at that time. This would result in a charge to earnings, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*. All derivatives are recognized in the Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated other comprehensive income (AOCI) and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Statement of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 9, Risk Management and Hedging Activities for further discussion of our derivative activity.

Utility Plant

Utility plant is stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in utility plant are assets under capital lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.0% and 7.9% for Montana for 2012 and 2011, respectively, and 8.0% and 7.8% for South Dakota for 2012 and 2011, respectively. AFUDC capitalized totaled $7.9 million for the year ended December 31, 2012 and $3.1 million for the year ended December 31, 2011 for Montana and South Dakota combined.

We capitalize preliminary survey and investigation charges related to the determination of the feasibility of transmission or generation utility projects in other deferred debits. Upon commencement of construction, these costs are transferred to construction work in process, and upon completion, these costs will be transferred to utility plant in service. As of December 31, 2012 and 2011, we have capitalized preliminary survey and investigation charges of approximately $1.2 million and $0.8 million, respectively. Capitalized costs are charged to operating expense if the development of the project is no longer feasible.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $5.0 million and $2.0 million for the years ended December 31, 2012 and 2011, respectively.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to 40 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.3% and 3.3% for 2012 and 2011, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission three coal-fired generating plants at the end of the useful life of each plant. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in accumulated depreciation.

Income Taxes

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Statements of Income and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if we have prior regulatory authorization for recovery of these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, then we capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Emission Allowances

We have sulfur dioxide (SO2) emission allowances and each allowance permits a generating unit to emit one ton of SO2 during or after a specified year. We have approximately 3,200 excess SO2 emission allowances per year for years 2017 through 2031, however these allowances have no carrying value in our Financial Statements and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO2 emission allowances are sold, we reflect the gain in operating income and cash received is reflected as an investing activity.

Accounting Standards Issued

There have been no new accounting pronouncements or changes in accounting pronouncements issued during the year ended December 31, 2012 that are of significance, or potential significance, to us.

Accounting Standards Adopted

In May 2011, the Financial Accounting Standards Board (FASB) issued guidance related to fair value measurement, which amends current guidance to achieve common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. The guidance expanded the disclosures for the unobservable inputs for Level 3 fair value measurements, requiring quantitative information to be disclosed related to (1) the valuation processes used, (2) the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, and (3) use of a nonfinancial asset in a way that differs from the asset's highest and best use. This revised guidance was effective during the first quarter of 2012. The adoption of this standard did not have a material effect on our financial statement disclosures.

(3) Regulatory Matters

Dave Gates Generating Station at Mill Creek (DGGS)

As a result of a Federal Energy Regulatory Commission (FERC) Administrative Law Judge's (ALJ) initial nonbinding decision issued in September 2012, we have cumulative deferred revenue of approximately $18.5 million, which is subject to refund and recorded within current regulatory liabilities in the Condensed Consolidated Balance Sheets. The ALJ concluded we should allocate only a fraction of the costs we believe (based on past practice) should be allocated to FERC jurisdictional customers. Our brief in opposition to the ALJ's initial decision is pending before the FERC.

Although we have no assurance as to timing, the FERC is expected to consider the matter and issue a binding decision during 2013. The FERC is not obligated to follow any of the ALJ's findings and conclusions, and the FERC can accept or reject the initial decision in whole or in part. If the FERC upholds the ALJ's decision and a portion of the costs are effectively disallowed, we would be required to assess DGGS for impairment. If we disagree with a decision issued by the FERC, we may pursue full appellate rights through rehearing and appeal to a United States Circuit Court of Appeals, which could extend into 2015. We continue to bill FERC jurisdictional customers interim rates that have been in effect since January 1, 2011. These interim rates are subject to refund plus interest pending final resolution at FERC.

Montana Electric and Natural Gas Tracker Filings

Each year we submit electric and natural gas tracker filings for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The Montana Public Service Commission (MPSC) reviews such filings and makes its cost recovery determination based on whether or not our electric and natural gas supply procurement activities were prudent.

We do not expect the MPSC to issue final orders related to our 2012 electric supply tracker filing, including our request for demand-side management (DSM) lost revenues, until at least the third quarter of 2013. As of March 31, 2013, we have deferred revenue of approximately $6.2 million related to DSM lost revenues, which is recorded within current regulatory liabilities in the Condensed Consolidated Balance Sheets.

Montana Natural Gas Production Assets

During the third quarter of 2012, we completed the purchase of natural gas production interests in northern Montana's Bear Paw Basin, including a 75% interest in two gas gathering systems (Bear Paw). We are collecting the cost of service for Bear Paw natural gas produced, including a return on our investment, through our natural gas supply tracker on an interim basis. We expect to file an application with the MPSC to place our Bear Paw assets in natural gas rate base during 2013 and this revenue is subject to refund until we receive MPSC approval of our application.

Montana Natural Gas Rate Filing

In September 2012, we filed a request with the MPSC for an annual natural gas delivery revenue increase of approximately $15.7 million. This request was based on a return on equity of 10.5%, a capital structure consisting of 52% debt and 48% equity and rate base of $309.5 million.

In April 2013, we reached a joint settlement with intervenors and received MPSC approval to increase our annual natural gas delivery rates by approximately $11.5 million, based on a return on equity of 9.8%.

Montana Avoided Cost Compliance Filing

Colstrip Energy Limited Partnership (CELP) is a QF with which we have a power purchase agreement (PPA) for approximately 306,600 MWH's annually through June 2024. Under the terms of the PPA with CELP, energy and capacity rates were fixed for the first fifteen years and beginning July 1, 2004, through the end of the contract, energy and capacity rates are to be determined each year pursuant to a formula, subject to annual review and approval by the MPSC. Until April 2013, the MPSC's most recent final order related to this compliance filing covered rates through June 30, 2006. We had been in litigation with CELP since 2007 over how to determine energy and capacity rates under the PPA. On November 1, 2012, an arbitration panel issued a final award in our favor. In April 2013, the MPSC issued a final order consistent with the arbitration panel's final award for the contract years July 1, 2006 through June 30, 2013.

(4) Equity Investments

The following table presents our equity investments reflected in the investments in subsidiary companies on the Balance Sheets (in thousands):

	December 31, 2012	December 31, 2011
Colstrip Unit 4 Basis Adjustment	$ (162,848)	$ (165,531)
Mountain States Transmission Intertie, LLC	9,379	18,296
Natural Gas Funding Trust	-	2,466
NorthWestern Services, LLC	(9,926)	(10,049)
Risk Partners Assurance, Ltd.	2,762	2,815
Total Investments in Subsidiary Companies	$ (160,633)	$ (152,003)

(5) Colstrip Energy Limited Partnership (CELP)

CELP is a QF with which we have a power purchase agreement (PPA) for approximately 306,600 MWH's annually through June 2024. Under the terms of the PPA with CELP, energy and capacity rates were fixed for the first fifteen years and beginning July 1, 2004, through the end of the contract, energy and capacity rates are to be determined each year pursuant to a formula, subject to annual review and approval by the MPSC. The MPSC's last final order covered rates through June 30, 2006. CELP filed a complaint against us and the MPSC in Montana district court in 2007, which contested the MPSC's orders. For further discussion of this litigation, see Note 20 - Commitments and Contingencies.

On November 1, 2012, an arbitration panel issued a final award in our favor. The final award confirmed that the rate methodology used by us for calculating the rates for the July 1, 2006 to June 30, 2011 period was consistent with the PPA and a previous final award issued by the same arbitration panel on October 30, 2009. Based on the clarity provided by the final award regarding the rate calculation for 2006 through the remainder of the PPA, we have updated the calculation of our QF liability and recorded a pre-tax gain of $47.9 million within operation expenses in the Statements of Income during the fourth quarter of 2012.

(6) Utility Plant

The following table presents the major classifications of our net utility plant (in thousands):

	December 31, 2012	December 31, 2011
Land and improvements	$ 73,370	$ 58,635
Building and improvements	220,607	161,349
Storage, distribution, and transmission	2,502,640	2,394,539
Generation	728,252	682,070
Construction work in process	115,304	72,581
Other equipment	238,853	222,973
	3,879,026	3,592,147
Less accumulated depreciation	(1,598,250)	(1,516,039)
	$ 2,280,776	$ 2,076,108

Plant and equipment under capital lease were $27.7 million and $29.8 million as of December 31, 2012 and 2011, respectively, which included $27.1 million and $29.2 million as of December 31, 2012 and 2011, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as an obligation under capital lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2012				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 61,084	$ 30,009	$ 46,188	$ 290,607
Accumulated depreciation	38,021	23,994	30,655	67,534
December 31, 2011				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 58,383	$ 29,991	$ 45,066	$ 287,462
Accumulated depreciation	39,246	23,046	29,740	59,586

(7) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our property, plant and equipment and other noncurrent liabilities. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligation (ARO) is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

Our AROs are primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, and our obligation to plug and abandon oil and gas wells at the end of their life. The following table presents the change in our gross conditional ARO (in thousands):

	December 31,			
	2012		2011	
Liability at January 1,	$	6,292	$	7,181
Accretion expense		473		493
Liabilities incurred		2,466		486
Liabilities settled		(35)		(1,970)
Revisions to cash flows		87		102
Liability at December 31,	$	9,283	$	6,292

Liabilities incurred includes amounts related to the natural gas production assets acquired.

Our regulated utility operations have, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. These amounts do not represent legal retirement obligations. As of December 31, 2012 and 2011, we have recognized accrued removal costs of $248.0 million and $235.3 million, respectively, which are classified as accumulated depreciation. In addition, for our generation properties, we have accrued non-ARO decommissioning costs since the generating units were first put into service in the amount of $16.5 million and $15.9 million as of December 31, 2012 and 2011, respectively, which are classified as accumulated depreciation.

We have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

(8) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2012 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

The long-term growth rates used for our reporting units reflect increased infrastructure investment. However, even if we assumed a 10% reduction in cash flows for either reporting unit, there would be no impairment of utility plant adjustments. Additionally, due to our regulated environment, if an increase in the cost of capital occurred, the effect on the corresponding reporting unit's fair value should be ultimately offset by a similar increase in the reporting unit's regulated revenues since those rates include a component that is based on the reporting unit's cost of capital.

(9) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a large portion of our electric and natural gas supply requirements within the Montana market. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts, such as fixed-price forward purchase and sales contracts. The objective of these transactions is to fix the price for a portion of anticipated energy purchases to supply our customers. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. These commodity costs are included in our cost tracking mechanisms and are recoverable from customers subject to prudence reviews by the applicable state regulatory commissions. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines. In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale; cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the normal purchase and normal sale scope exception (NPNS) to most of our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no amounts recorded in the Financial Statements at December 31, 2012 and 2011. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Mark-to-Market Accounting

Certain contracts for the purchase of natural gas associated with our gas utility operations do not qualify for NPNS. These are typically forward purchase contracts for natural gas where we lock in a fixed price, settle the contracts financially and do not take physical delivery of the natural gas. We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements; therefore, we record a regulatory asset or liability based on changes in market value.

The following table represents the fair value and location of derivative instruments subject to mark-to-market accounting (in thousands). For more information on the determination of fair value see Note 10 - Fair Value Measurements.

Mark-to-Market Transactions	Balance Sheet Location	December 31, 2012		2011
Natural gas net derivative liability	Current and Accrued Liabilities	$	5,428	$ 20,312

The following table represents the net change in fair value for these derivatives (in thousands):

Derivatives Subject to Regulatory Deferral	Unrealized gain recognized in Regulatory Assets December 31, 2012		2011
Natural gas	$	14,884	$ 9,400

Credit Risk

We are exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties.

We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements - standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements - standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements - standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements - standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

As of December 31, 2012, none of the forward purchase contracts that do not qualify for NPNS contain credit risk-related contingent features.

Interest Rate Swaps Designated as Cash Flow Hedges

If we enter into contracts to hedge the variability of cash flows related to forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. The relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods in which earnings are affected by the variability of the cash flows of the related hedged item. Any ineffective portion of all hedges would be recognized in current-period earnings. Cash flows related to these contracts are classified in the same category as the transaction being hedged.

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI. We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these derivative instruments on the Financial Statements (in thousands)

Cash Flow Hedges	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2012
Interest rate contracts	Interest on long-term debt	$ 1,188

Approximately $6.9 million of the pre-tax gain on these cash flow hedges is remaining in AOCI as of December 31, 2012, and we expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest on long-term debt during the next twelve months. These gains relate to swaps previously terminated, and we have no current interest rate swaps outstanding.

(10) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

A fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs has been established by the applicable accounting guidance. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. Normal purchases and sales transactions are not included in the fair values by source table as they are not recorded at fair value. There were no transfers between levels for the periods presented. See Note 9 - Risk Management and Hedging Activities for further discussion.

December 31, 2012	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Other special deposits	$ 2,920	$ —	$ —	$ —	$ 2,920
Rabbi trust investments	10,522	—	—	—	10,522
Derivative liability (1)	—	(5,428)	—	—	(5,428)
Total	**$ 13,442**	**$ (5,428)**	**$ —**	**$ —**	**$ 8,014**
December 31, 2011					
Other special deposits	$ 3,999	$ —	$ —	$ —	$ 3,999
Rabbi trust investments	8,049	—	—	—	8,049
Derivative liability (1)	—	(20,312)	—	—	(20,312)
Total	**$ 12,048**	**$ (20,312)**	**$ —**	**$ —**	**$ (8,264)**

(1) The changes in the fair value of these derivatives are deferred as a regulatory asset or liability until the contracts are settled. Upon settlement, associated proceeds or costs are passed through the applicable cost tracking mechanism to customers.

We present our derivative assets and liabilities on a net basis in the Balance Sheets. The table above disaggregates our net derivative assets and liabilities on a gross contract-by-contract basis as required and classifies each individual asset or liability within the appropriate level in the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts. These gross balances are intended solely to provide information on sources of inputs to fair value and do not represent our actual credit exposure or net economic exposure. Increases and decreases in the gross components presented in each of the levels in this table also do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices.

Other special deposits represent amounts held in money market mutual funds. Rabbi trust assets represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets. Fair value for the commodity derivatives was determined using internal models based on quoted forward commodity prices. We consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The fair value measurement of liabilities also reflects the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Consideration of our own credit risk did not have a material impact on our fair value measurements.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt (including current portion)	$ 1,055,074	$ 1,229,233	$ 905,049	$ 1,066,681

Notes payable consist of commercial paper and are not included in the table above as carrying value approximates fair value. The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(11) Notes Payable

Notes payable and the corresponding weighted average interest rates as of December 31 were as follows (dollars in millions, except for percentages):

	2012			2011		
Notes Payable		**Balance**	**Interest Rate**		**Balance**	**Interest Rate**
Commercial Paper	$	122.9	0.53%	$	166.9	0.57%

The following information relates to commercial paper for the years ended December 31 (dollars in millions):

		2012		2011
Maximum short-term debt outstanding	$	166.9	$	166.9
Average short-term debt outstanding	$	78.9	$	83.4
Weighted-average interest rate		0.48%		0.42%

Under our commercial paper program we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $250 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility. See Note 12 - Long-Term Debt, for more information on our unsecured revolving credit facility.

(12) **Long-Term Debt**

Long-term debt consisted of the following (in thousands):

	Due	December 31, 2012	December 31, 2011
Unsecured Debt:			
Unsecured Revolving Line of Credit	2016	$ —	$ —
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	—
South Dakota—4.30%	2052	20,000	—
Montana—6.04%	2016	150,000	150,000
Montana—6.34%	2019	250,000	250,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	—
Montana—4.30%	2052	40,000	—
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Other Long Term Debt:			
Discount on Notes and Bonds	—	(131)	(156)
		$ 1,055,074	$ 905,049

Unsecured Revolving Line of Credit

Our $300 million unsecured revolving line of credit is scheduled to expire on June 30, 2016, and does not amortize. The facility has an accordion feature that allows us to increase the size up to $350 million. The facility bears interest at the lower of prime or available rates tied to the LIBOR plus a credit spread, ranging from 0.88% to 1.75% over the LIBOR. A total of eight banks participate in the facility, with no one bank providing more than 17% of the total availability. While no direct borrowings were outstanding as of December 31, 2012, letters of credit of $3.5 million were outstanding. Commitment fees for the unsecured revolving line of credit were $0.5 million and $0.7 million for the years ended December 31, 2012 and 2011, respectively.

The credit facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the credit facility; however a default on the credit facility would not trigger a default on any other obligations.

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In August 2012, we issued $90 million aggregate principal amount of Montana and South Dakota First Mortgage Bonds at a fixed interest rate of 4.15% maturing in 2042. At the same time, we also issued $60 million aggregate principal amount of Montana and South Dakota First Mortgage Bonds at a fixed interest rate of 4.30% maturing in 2052. The bonds are secured by our electric and natural gas assets in the respective jurisdictions. The bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used primarily to repay commercial paper borrowings.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt during the next five years are zero in 2013 through 2015, $150.0 million in 2016, and zero in 2017.

As of December 31, 2012, we are in compliance with our financial debt covenants.

(13) Related Party Transactions

Accounts receivable from and payables to associated companies primarily include intercompany billings for direct charges, overhead, and income tax obligations. The following table reflects our accounts receivable from and accounts payable to associated companies (in thousands):

	December 31, 2012	December 31, 2011
Accounts Receivable from Associated Companies:		
Mountain States Transmission Intertie, LLC	$ -	$ 2,650
NorthWestern Services, LLC	2,026	2,184
Risk Partners Assurance, Ltd.	18	18
	$ 2,044	$ 4,852
Accounts Payable to Associated Companies:		
Natural Gas Funding Trust	$ -	$ 71

(14) Income Taxes

Our effective tax rate differs from the federal statutory tax rate of 35% primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions and state tax benefit of bonus depreciation deductions. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. We have elected under Internal Revenue Code 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

The components of the net deferred income tax liability recognized in our Balance Sheets are related to the following temporary differences (in thousands)

	December 31, 2012	2011
Pension / postretirement benefits	$ 59,098	$ 41,898
NOL carryforward	—	51,941
Property taxes	18,023	—
Unbilled revenue	15,942	6,297
Customer advances	13,660	16,157
Reserves and accruals	3,202	4,378
Compensation accruals	11,303	7,269
AMT credit carryforward	10,588	6,897
Environmental liability	9,701	9,670
Regulatory liability	1,526	1,098
QF obligations	1,462	20,596
Other, net	3,523	1,862
Valuation allowance	—	(3,834)
Deferred Tax Asset	**148,028**	**164,229**
Excess tax depreciation	(276,453)	(273,001)
Goodwill amortization	(118,313)	(96,233)
Flow through depreciation	(63,551)	(49,740)
Regulatory assets	(24,173)	(14,323)
Property taxes	—	(511)
Deferred Tax Liability	**(482,490)**	**(433,808)**
Deferred Tax Liability, net	$ (334,462)	$ (269,579)

At December 31, 2012 we estimate our total federal NOL carryforward to be approximately $255.1 million. If unused, our federal NOL carryforwards will expire as follows: $2.5 million in 2026; $1.0 million in 2027; $95.5 million in 2028; $23.8 million in 2029; $3.2 million in 2030; $127.5 million in 2031; and $1.6 million in 2032. We estimate our state NOL carryforward as of December 31, 2012 is approximately $201.3 million. If unused, our state NOL carryforwards will expire as follows: $3.0 million in 2013; $0.8 million in 2014; $74.0 million in 2015; $18.6 million in 2016; $2.5 million in 2017; $101.2 million in 2018; and $1.2 million in 2019. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2012	2011
Unrecognized Tax Benefits at January 1	$ 131,949	$ 120,859
Gross increases - tax positions in prior period	—	—
Gross decreases - tax positions in prior period	(1,766)	(15,774)
Gross increases - tax positions in current period	2,391	26,864
Gross decreases - tax positions in current period	(19,283)	—
Unrecognized Tax Benefits at December 31	$ 113,291	$ 131,949

Our unrecognized tax benefits include approximately $79.2 million related to tax positions as of each of December 31, 2012 and 2011, that if recognized, would impact our annual effective tax rate. We do not anticipate total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitations within the next twelve months.

The IRS issued guidance during the third quarter of 2011 providing a safe harbor method for determining the tax treatment of repair costs related to electric transmission and distribution property. That guidance was updated in the third quarter of 2012 to allow companies additional time to adopt the safe harbor method. We are evaluating whether or not we want to elect the safe harbor method, which may result in a change in related repairs deductions and unrecognized tax benefits. We expect to complete our evaluation by the second quarter of 2013.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the years ended December 31, 2012 and 2011, we have not recognized expense for interest or penalties, and do not have any amounts accrued at either December 31, 2012 or 2011, for the payment of interest and penalties.

Our federal tax returns from 2000 forward remain subject to examination by the IRS.

(15) Other Comprehensive (Loss) Income

The following tables display the components of Other Comprehensive Loss, after-tax, and the related tax effects (in thousands):

	December 31,					
	2012			2011		
	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount
Foreign currency translation adjustment	$ (57)	$ —	$ (57)	$ 25	—	$ 25
Reclassification of net gains on derivative instruments to net income	(1,188)	457	(731)	(1,188)	458	(730)
Reclassification of deferred tax liability on net gains on derivative instruments	—	—	—	—	(3,572)	(3,572)
Pension and postretirement medical liability adjustment	(896)	345	(551)	(736)	155	(581)
Other comprehensive loss	$ (2,141)	$ 802	$ (1,339)	$ (1,899)	$ (2,959)	$ (4,858)

Balances by classification included within AOCI on the Balance Sheets are as follows, net of tax (in thousands):

	December 31, 2012	December 31, 2011
Foreign currency translation	$ 366	$ 420
Derivative instruments designated as cash flow hedges	4,243	4,975
Pension and postretirement medical plans	(2,292)	(1,739)
Accumulated other comprehensive income	2,317	3,656

(16) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2012 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2013	$	1,781
2014		1,192
2015		820
2016		620
2017		474

Lease and rental expense incurred was $2.2 million and $2.2 million for the years ended December 31, 2012 and 2011, respectively.

(17) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our financial statements. See Note 19 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value of plan assets, and a statement of the funded status (in thousands):

	Pension Benefits December 31, 2012	Pension Benefits December 31, 2011	Other Postretirement Benefits December 31, 2012	Other Postretirement Benefits December 31, 2011
Change in Benefit Obligation:				
Obligation at beginning of period	$ 536,536	$ 478,790	$ 32,427	$ 35,968
Service cost	11,488	10,199	541	437
Interest cost	23,823	24,394	1,167	1,348
Plan amendments	—	—	—	(464)
Actuarial loss (gain)	59,071	44,586	2,508	(2,056)
Benefits paid	(21,275)	(21,433)	(2,603)	(2,806)
Benefit obligation at end of period	$ 609,643	$ 536,536	$ 34,040	$ 32,427
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 432,637	$ 428,152	$ 15,502	$ 17,201
Return on plan assets	49,874	14,218	1,789	340
Employer contributions	11,700	11,700	1,205	767
Benefits paid	(21,275)	(21,433)	(2,603)	(2,806)
Fair value of plan assets at end of period	$ 472,936	$ 432,637	$ 15,893	$ 15,502
Funded Status	$ (136,707)	$ (103,899)	$ (18,147)	$ (16,925)
Amounts recognized in the balance sheet consist of:				
Current liability	—	—	(1,082)	(1,075)
Noncurrent liability	(136,707)	(103,899)	(17,065)	(15,850)
Net amount recognized	$ (136,707)	$ (103,899)	$ (18,147)	$ (16,925)
Amounts recognized in regulatory assets consist of:				
Prior service (cost) credit	(994)	(1,241)	21,396	23,545
Net actuarial loss	(160,610)	(130,062)	(9,488)	(10,025)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(1,453)	(1,604)
Net actuarial gain	—	—	(2,432)	(1,051)
Total	$ (161,604)	$ (131,303)	$ 8,023	$ 10,865

The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	Pension Benefits December 31, 2012	Pension Benefits December 31, 2011
Projected benefit obligation	$ 609.6	$ 536.5
Accumulated benefit obligation	606.2	533.5
Fair value of plan assets	472.9	432.6

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2012	2011	2012	2011
Components of Net Periodic Benefit Cost				
Service cost	$ 11,488	$ 10,199	$ 541	$ 437
Interest cost	23,823	24,394	1,167	1,348
Expected return on plan assets	(29,996)	(30,462)	(1,021)	(1,185)
Amortization of prior service cost (credit)	246	246	(1,998)	(1,998)
Recognized actuarial loss	8,646	2,516	790	658
Net Periodic Benefit Cost (Credit)	$ 14,207	$ 6,893	$ (521)	$ (740)

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

We estimate amortizations from regulatory assets into net periodic benefit cost during 2013 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 246	$ (1,998)
Accumulated loss	10,984	901

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2012 and 2011. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2012 and 2011, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Considering this information and future expectations for asset returns, we are maintaining a 7.00% long-term rate of return on assets assumption for 2013.

The health care cost trend rates are established through a review of actual recent cost trends and projected future trends. Our retiree medical trend assumptions are the best estimate of expected inflationary increases to our healthcare costs. Due to the relative size of our retiree population (under 800 members), the assumptions used are based upon both nationally expected trends and our specific expected trends. Our average increase remains consistent with the nationally expected trends.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2012	2011	2012	2011
Discount rate	3.55-3.80%	4.40-4.55% %	2.25-3.20%	3.50-4.30% %
Expected rate of return on assets	7.00	7.25	7.00	7.25
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 8.75% in 2012 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually by 0.25% per year to an ultimate trend of 4.5% by the year 2029. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially fully invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5%, is as follows:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2012	2011	2012	2011
Domestic debt securities	40.0%	40.0%	40.0%	40.0%
International debt securities	10.0	10.0	—	—
Domestic equity securities	40.0	40.0	50.0	50.0
International equity securities	10.0	10.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2012	2011	2012	2011	2012	2011
Cash and cash equivalents	—	—	—	—	3.4%	2.0%
Domestic debt securities	39.5	39.5	38.3	38.4	37.8	39.4
International debt securities	9.9	10.6	10.6	11.2	—	—
Domestic equity securities	40.2	40.3	40.6	40.9	49.8	49.8
International equity securities	10.4	9.6	10.5	9.5	9.0	8.8
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. and international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. While the portfolio may invest in high yield securities, the average quality must be rated at least "investment grade" by rating agencies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. We also invest in international equities with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the Securities and Exchange Commission (SEC). Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

The fair value of our plan assets at December 31, 2012, by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 508		$ 508	$ —
Equity securities: (1)				
US small/mid cap growth	16,229	—	16,229	—
US small/mid cap value	16,297	—	16,297	—
US large cap growth	49,811	—	49,811	—
US large cap value	51,655	—	51,655	—
US large cap passive	56,194	—	56,194	—
Non-US core	36,358	—	36,358	—
Emerging markets	12,713	—	12,713	—
Fixed income securities: (2)				
US core opportunistic	90,742	—	90,742	—
US passive	48,710	—	48,710	—
Long duration	6,455	—	6,455	—
Long duration investment grade	7,091	—	7,091	—
Long duration passive	5,239	—	5,239	—
Non-US passive	46,856	—	46,856	—
Active long corporate	18,540	—	18,540	—
Participating group annuity contract	9,538	—	9,538	—
	$ 472,936	$ —	$ 472,936	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 533	$ —	$ 533	$ —
Equity securities: (1)				
US small/mid cap growth	567	—	567	—
US small/mid cap value	567	—	567	—
S&P 500 index	6,360	—	6,360	—
US large cap growth	132	—	132	—
US large cap value	139	—	139	—
US large cap passive	151	—	151	—
Non-US core	1,323	—	1,323	—
Emerging markets	108	—	108	—
Fixed income securities: (2)				
Passive bond market	1,205	—	1,205	—
US core opportunistic	4,440	—	4,440	—
US passive	138	—	138	—
Long duration	16	—	16	—
Long duration investment grade	21	—	21	—
Long duration passive	16	—	16	—
Non-US passive	124	—	124	—
Active long corporate	53	—	53	—
	$ 15,893	$ —	$ 15,893	$ —

The fair value of our plan assets at December 31, 2011, by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 313	$ —	$ 313	$ —
Equity securities: (1)				
US small/mid cap growth	14,922	—	14,922	—
US small/mid cap value	15,290	—	15,290	—
US large cap growth	43,786	—	43,786	—
US large cap value	46,248	—	46,248	—
US large cap passive	54,477	—	54,477	—
Non-US core	41,270	—	41,270	—
Fixed income securities:(2)				
US core opportunistic	80,702	—	80,702	—
US passive	41,630	—	41,630	—
Long duration	6,998	—	6,998	—
Long duration investment grade	13,058	—	13,058	—
Long duration passive	5,441	—	5,441	—
Non-US passive	46,023	—	46,023	—
Active long corporate	12,730	—	12,730	—
Participating group annuity contract	9,749	—	9,749	—
	$ 432,637	$ —	$ 432,637	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 270	—	$ 270	—
Equity securities: (1)				
US small/mid cap growth	643	—	643	—
US small/mid cap value	636	—	636	—
S&P 500 index	5,671	—	5,671	—
US large cap growth	180	—	180	—
US large cap value	192	—	192	—
US large cap passive	227	—	227	—
Non-US core	1,379	—	1,379	—
Fixed income securities: (2)				
Passive bond market	1,156	—	1,156	—
US core opportunistic	4,603	—	4,603	—
US passive	185	—	185	—
Long duration	25	—	25	—
Long duration investment grade	61	—	61	—
Long duration passive	26	—	26	—
Non-US passive	191	—	191	—
Active long corporate	57	—	57	—
	$ 15,502	$ —	$ 15,502	$ —

(1) This category consists of active and passive managed equity funds, which are invested in multiple strategies to diversify risks and reduce volatility.

(2) This category consists of investment grade bonds of issuers from diverse industries, debt securities issued by international, national, state and local governments, and asset-backed securities. This includes both active and passive managed funds.

For further discussion of the three levels of the fair value hierarchy see Note 10 - Fair Value Measurements.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements.

Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, we estimate that we will not have a minimum annual required contribution for 2013. We do expect to contribute approximately $11.7 million to our pension plans during 2013. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

Due to the regulatory treatment of pension costs in Montana, expense is calculated using the average of our actual and estimated funding amounts from 2005 through 2013, therefore changes in our funding estimates creates increased volatility to earnings. Annual contributions to each of the pension plans are as follows (in thousands):

	2012	2011	2010
NorthWestern Energy Pension Plan (MT)	$ 10,500	$ 10,500	$ 9,000
NorthWestern Pension Plan (SD)	1,200	1,200	1,000
	$ 11,700	$ 11,700	$ 10,000

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2013	$ 25,180	$ 3,686
2014	26,439	3,639
2015	27,694	3,544
2016	29,682	3,438
2017	30,823	3,212
2018-2022	173,402	12,636

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2012and 2011 were $7.2 million and $6.7 million, respectively.

(18) Stock-Based Compensation

We grant stock-based awards through our 2005 Long-Term Incentive Plan (LTIP), which includes restricted stock awards and performance share awards. As of December 31, 2012, there were 836,528 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Restricted Stock and Performance Share Awards

Performance share awards were granted under the 2005 LTIP during 2012 and 2011. With these awards, shares will vest if, at the end of the three-year performance period, we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both a market and performance based component. The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics: (i) cumulative net income and return on equity growth; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance share awards. The fair value of the net income component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of restricted stock is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2012	2011
Risk-free interest rate	0.38%	1.40%
Expected life, in years	3	3
Expected volatility	20.2% to 34.2%	25.6% to 47.0%
Dividend yield	4.1%	4.9%

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2012, are as follows:

	Performance Share Awards		Restricted Stock Awards	
	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	204,713	$ 20.07	2,000	$ 25.44
Granted	86,546	25.18	2,500	35.78
Vested	(100,723)	19.66	(3,500)	33.01
Forfeited	(3,781)	20.96	—	—
Remaining nonvested grants	186,755	$ 22.64	1,000	$ 24.77

We recognized compensation expense of $2.8 million and $2.1 million for the years ended December 31, 2012 and 2011, respectively, and a related income tax benefit of $0.4 million and $1.6 million for the years ended December 31, 2012 and 2011, respectively. As of December 31, 2012, we had $2.5 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as other paid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 2.2 years. The total fair value of shares vested was $2.0 million and $2.9 million for the years ended December 31, 2012 and 2011, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2012, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	8,596	$ 28.00
Granted	8,941	27.42
Vested	—	—
Forfeited	—	—
Remaining nonvested grants	17,537	$ 27.70

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2012 and 2011, DSUs issued to members of our Board totaled 31,801 and 31,032, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2012 and 2011 was approximately $0.9 million and $2.3 million, respectively.

(19) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 98% of our regulatory assets and 100% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31,	
			2012	2011
			(in thousands)	
Pension	17	Undetermined	$ 143,672	$ 128,844
Employee related benefits	17	Undetermined	20,911	21,527
Distribution infrastructure projects		5 Years	15,679	4,883
Environmental clean-up	20	Various	16,497	16,998
Energy supply derivatives	9	1 Year	5,428	20,312
Income taxes	14	Plant Lives	162,154	124,967
Other		Various	18,146	12,344
Total regulatory assets			$ 382,487	$ 329,875
Gas storage sales		27 Years	$ 11,251	$ 11,672
Unbilled revenue		1 Year	12,030	10,597
Environmental clean-up		1 Year	1,482	1,733
State & local taxes & fees		1 Year	537	2,578
Other		Various	2,272	1,772
Total regulatory liabilities			$ 27,572	$ 28,352

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis. The MPSC allows recovery of other employee related benefits on a cash basis.

Montana Distribution System Infrastructure Project (DSIP)

We have an accounting order to defer certain incremental operating and maintenance expenses associated with DSIP. Pursuant to the order, we have deferred expenses incurred during 2011 and 2012 as a regulatory asset associated with the phase-in portion of the DSIP. These costs will be amortized into expense over five years beginning in 2013.

Energy Supply Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. Certain contracts for the purchase of natural gas associated with our gas utility operations do not qualify for NPNS. We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements; therefore, we record a regulatory asset or liability based on changes in market value.

Environmental clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 20 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. We record changes in the regulatory asset consistent with changes in our environmental liabilities. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse.

Unbilled Revenue

In accordance with regulatory guidance in South Dakota, we recognize revenue when it is billed. Accordingly, we record a regulatory liability to offset unbilled revenue.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and recover these amounts. The MPSC has authorized recovery in the property tax tracker of approximately 60% of the estimated increase in our local taxes and fees (primarily property taxes) as compared to the related amount included in rates during our last general rate case.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(20) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Policies Act. The QFs require us to purchase minimum amounts of energy at prices ranging from $71 to $136 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.1 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $0.9 billion through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets as a regulatory disallowance liability pursuant to ASC 980. The following summarizes the change in the QF liability (in thousands):

	December 31, 2012	December 31, 2011
Beginning QF liability	$ 184,187	$ 177,322
Gain on CELP arbitration decision	(47,894)	—
Unrecovered amount	(12,014)	(6,043)
Interest expense	12,373	12,908
Ending QF liability	$ 136,652	$ 184,187

See Note 5 – Colstrip Energy Limited Partnership (CELP) for additional discussion related to the adjustment of the QF liability related to the CELP arbitration decision.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2013	$ 64,223	$ 55,462	$ 8,761
2014	67,283	56,025	11,258
2015	69,606	56,598	13,008
2016	71,598	57,188	14,410
2017	73,622	57,789	15,833
Thereafter	800,262	625,616	174,646
Total	$ 1,146,594	$ 908,678	$ 237,916

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 25 years. Costs incurred under these contracts were approximately $340.8 million and $390.3 million for the years ended December 31, 2012 and 2011, respectively. As of December 31, 2012, our commitments under these contracts are $293.6 million in 2013, $192.5 million in 2014, $117.5 million in 2015, $117.3 million in 2016, $103.6 million in 2017, and $737.8 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

The operation of electric generating, transmission and distribution facilities, and gas gathering, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs become fixed and reliably determinable.

Our liability for environmental remediation obligations is estimated to range between $28.3 million to $36.4 million, primarily for manufactured gas plants discussed below. As of December 31, 2012, we have a reserve of approximately $31.5 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. Over time, as specific laws are implemented and we gain experience in operating under them, a portion of the costs related to such laws will become determinable, and we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our financial position or ongoing operations.

Manufactured Gas Plants - Approximately $26.2 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources (DENR). Our current reserve for remediation costs at this site is approximately $12.4 million, and we estimate that approximately $8.8 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. During 2005, the Nebraska Department of Environmental Quality (NDEQ) conducted Phase II investigations of soil and groundwater at our Kearney and Grand Island sites. During 2006, the NDEQ released to us the Phase II Limited Subsurface Assessments performed by the NDEQ's environmental consulting firm for Kearney and Grand Island. In February 2011, NDEQ completed an Abbreviated Preliminary Assessment and Site Investigation Report for Grand Island, which recommended additional ground water testing. In April of 2012, we received a letter from NDEQ regarding a recently completed Vapor Intrusion Assessment Report and an invitation to join NDEQ's Voluntary Cleanup Program (VCP). We declined NDEQ's offer to join its VCP at this time and also committed to conducting a limited soil vapor investigation. We will work independently to fully characterize the nature and extent of impacts associated with the former MGP. After the site has been fully characterized, we will discuss the possibility of joining NDEQ's VCP. Our reserve estimate includes assumptions for additional ground water testing. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

In addition, we own or have responsibility for sites in Butte, Missoula and Helena, Montana on which former manufactured gas plants were located. An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. The Butte and Helena sites were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to excess regulated pollutants in the groundwater. Voluntary soil and coal tar removals were conducted in the past at the Butte and Helena locations in accordance with MDEQ requirements. We have conducted additional groundwater monitoring at the Butte and Missoula sites and, at this time, we believe natural attenuation should address the conditions at these sites; however, additional groundwater monitoring will be necessary. Monitoring of groundwater at the Helena site is ongoing and will be necessary for an extended period of time. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action at the Helena site or if any additional actions beyond monitored natural attenuation will be required.

Global Climate Change - There are national and international efforts to adopt measures related to global climate change and the contribution of emissions of greenhouse gases (GHG) including, most significantly, carbon dioxide. These efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four electric generating plants, all of which are coal fired and operated by other companies. We have undivided interests in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of Federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In the absence of such legislation, the EPA is regulating GHG emissions under its existing authority pursuant to the Clean Air Act. For example, EPA regulations now require that major sources in the United States annually report information regarding, and obtain certain permits for, their GHG emissions.

In March 2012, the EPA proposed New Source Performance Standards that would limit carbon dioxide emissions from new electric generating units (EGUs). The proposed limits would not apply to existing or reconstructed EGUs. The proposed rule was part of an agreement to settle litigation brought by states, municipalities and environmental groups. The EPA accepted comments on the proposed standards through the end of June 2012. The EPA currently estimates that the final standards will be issued in March 2013.

On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing federal common law nuisance actions against electrical utility companies based on their alleged contribution to climate change. The Supreme Court's decision did not, however, address state law claims. This decision is expected to affect other pending federal climate change litigation. In addition, on June 26, 2012 a federal court issued a ruling affirming several of the EPA's greenhouse gas rules, which had been challenged by industry petitioners and certain states. Although we are not a party to any of these proceedings, additional litigation in federal and state courts over these issues is continuing.

Physical impacts of climate change may present potential risks for severe weather, such as floods and tornadoes, in the locations where we operate or have interests. Furthermore, requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance, increase our costs of procuring electricity in the marketplace or curtail the demand for fossil fuels such as oil and gas. In addition, we believe future legislation and regulations that affect GHG emissions from power plants are likely, although technology to efficiently capture, remove and/or sequester such emissions may not be available within a timeframe consistent with the implementation of such requirements. We cannot predict with any certainty whether these risks will have a material impact on our operations.

Coal Combustion Residuals (CCRs) - In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and scrubber wastes. Under one approach, the EPA would regulate CCRs as a hazardous waste under Subtitle C of RCRA. This approach would have significant impacts on coal-fired plants, and would require plants to retrofit their operations to comply with hazardous waste requirements from the generation of CCRs and associated waste waters through transportation and disposal. This could also have a negative impact on the beneficial use of CCRs and the current markets associated with such use. The second approach would regulate CCRs as a solid waste under Subtitle D of RCRA. This approach would only affect disposal, most significantly any wet disposal, of CCRs. The EPA has not yet issued a final CCR rule; however, litigation has commenced to require them to do so. In addition, legislation was introduced in Congress to regulate coal ash in the absence of EPA action. We cannot predict at this time the final requirements of any CCR regulations or legislation and what impact, if any, they would have on us, but the costs of complying with any such requirements could be significant.

Water Intakes - Section 316(b) of the Federal Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. Permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA takes action to address several court decisions that rejected portions of previous rules and confirmed that the EPA has discretion to consider costs relative to benefits in developing cooling water intake structure regulations. In March 2011, the EPA proposed a rule to address impingement and entrainment of aquatic organisms at existing cooling water intake structures. The EPA is under a consent decree to issue a final rule by June 2013. When a final rule is issued and implemented, additional capital and/or increased operating costs may be incurred. The costs of complying with any such final water intake standards are not currently determinable, but could be significant.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures

The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act that could require the installation of emission control equipment at the generation plants where we have joint ownership.

The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze in national parks and wilderness areas across the United States. The Clean Air Visibility Rule requires the installation and operation of Best Available Retrofit Technology (BART) to achieve emissions reductions from designated sources (including certain electric generating units) that are deemed to cause or contribute to visibility impairment in such 'Class I' areas.

In December 2011, the EPA issued a final rule relating to Mercury and Air Toxics Standards (MATS), which was formerly the proposed Maximum Achievable Control Technology standards for hazardous air pollutant emissions from new and existing electric generating units. Among other things, these MATS standards set stringent emission limits for acid gases, mercury, and other hazardous air pollutants. Facilities that are subject to the MATS must come into compliance within three years after the effective date of the rule (or by 2015) unless a one year extension is granted on a case-by-case basis. This compliance deadline has been delayed for new power plants pending the EPA's reconsideration of certain MATS emission limits for these sources, which the EPA expects to finalize in March 2013. Numerous challenges to the MATS standards have been filed with the EPA and in Federal court and we cannot predict the outcome of such challenges.

On July 7, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to reduce emissions from electric generating units that interfere with the ability of downwind states to achieve ambient air quality standards. Under CSAPR, significant reductions in emissions of nitrogen oxide (NOx) and sulfur dioxide (SO2) were to be required beginning in 2012. After having issued a stay of CSAPR earlier this year, however, a Federal court found that CSAPR violated federal law and ordered that it be vacated. The Clean Air Interstate Rule remains in effect until the EPA issues a valid replacement. It is unknown whether the EPA will petition the Supreme Court to review the Federal court's ruling.

We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa and Montana that are or may become subject to various regulations that have been issued or proposed under the Clean Air Act, as discussed below.

South Dakota. The South Dakota DENR determined that the Big Stone Plant, of which we have a 23.4% ownership, is subject to the BART requirements of the Regional Haze Rule. South Dakota DENR's State Implementation Plan (SIP) was approved by the EPA in May 2012. Under the SIP, the Big Stone plant must install and operate a new BART compliant air quality control system (AQCS) to reduce SO2, NOx and particulate emissions as expeditiously as practicable, but no later than five years after the EPA's approval of the SIP. The current project cost for the AQCS is estimated to be approximately $490 million (our share is 23.4%) and it is expected to be operational by 2016.

Our incremental capital expenditure projections include amounts related to our share of the BART technologies at Big Stone based on current estimates. We could, however, face additional capital or financing costs. We will seek to recover any such costs through the regulatory process. The SDPUC has historically allowed timely recovery of the costs of environmental improvements; however, there is no precedent on a project of this size.

Based on the finalized MATS standards, it appears that Big Stone would meet the requirements by installing the AQCS system and using mercury control technology such as activated carbon injection. Mercury emissions monitoring equipment is already installed at Big Stone, but its operation has been put on hold pending additional regulatory direction. The equipment will need to be reevaluated for operability under the final rule.

North Dakota. The North Dakota Regional Haze SIP requires the Coyote generating facility, of which we have 10.0% ownership, to reduce its NOx emissions. Coyote must install control equipment to limit its NOx emissions to 0.5 pounds per million Btu as calculated on a 30-day rolling average basis, including periods of start-up and shutdown, beginning on July 1, 2018. The current estimate of the total cost of the project is approximately $6 million (our share is 10.0%).

Based on the finalized MATS standards, it appears that Coyote would meet the requirements by using mercury control technology such as activated carbon injection.

Iowa. The Neal 4 generating facility, of which we have an 8.7% ownership, is installing a scrubber, a baghouse, activated carbon and a selective non-catalytic reduction system to comply with national ambient air quality standards and MATS standards. These improvements are also expected to result in compliance with the regional haze provisions of the Clean Air Act. Capital expenditures for such equipment are currently estimated to be approximately $270 million (our share is 8.7%). The plant began incurring such costs in 2011 and the project is expected to be complete in 2013.

Montana. Colstrip Unit 4, a coal fired generating facility in which we have a 30% interest, is currently controlling emissions of mercury under regulations issued by the State of Montana, which are more strict than the Federal MATS standard. The owners do not believe additional equipment will be necessary to meet the MATS standards for mercury, and anticipate meeting all other expected MATS emissions limitations required by the rule without additional costs except those costs related to increased monitoring frequency. These additional costs are not expected to be significant.

In September 2012, a final Federal Implementation Plan for Montana was published in the Federal Register to address regional haze. As finalized, Colstrip Unit 4 does not have to improve removal efficiency for pollutants that contribute to regional haze. The plan is reviewed every five years and Colstrip Unit 4 could be impacted during a subsequent review period.

See 'Legal Proceedings - Notice of Intent to Sue Colstrip Owners' below for discussion of potential Sierra Club litigation.

Other - We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and

- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Colstrip Litigation

On July 25, 2012, the Sierra Club and the Montana Environmental Information Center (MEIC) served on each of the individual owners of the Colstrip Steam Electric Station (CSES), including us and the owner or managing agent of the station, a notice of intent to sue for alleged violations of the federal Clean Air Act, 42 U.S.C. § 7401 et seq. Since serving the initial notice of intent to sue, the Sierra Club and MEIC have revised it three times.

On March 6, 2013, the Sierra Club and the MEIC (Plaintiffs) filed suit in the United States District Court for the District of Montana against the individual owners of the CSES, including us, and the operator or managing agent of the station. Plaintiffs' complaint, which includes 39 claims for relief, alleges violations of the Clean Air Act and seeks injunctive and declaratory relief, civil penalties, imposition of a beneficial environmental project, and recovery of their attorney fees. Plaintiffs have identified physical changes made at the CSES between 1992 and 2012, which they allege have increased emissions of SO_2, NO_x and particulate matter and were "major modifications" subject to permitting requirements under the Clean Air Act. They also have alleged violations of the requirements related to Part 70 Operating Permits, as well as provisions in the Montana State Implementation Plan regulating the opacity of emissions. We intend to vigorously defend this lawsuit. Due to the preliminary nature of the lawsuit, at this time, we cannot predict or determine the outcome of the lawsuit, nor is it reasonably possible to estimate the amount of loss, if any, that would be associated with an adverse decision.

Other Legal Proceedings

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

(21) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 18 - Stock-Based Compensation.

In February 2012, we filed a shelf registration statement with the SEC that can be used for the issuance of debt or equity securities. In April 2012, we entered into an Equity Distribution Agreement pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. Through December 31, 2012, we have received net proceeds of approximately $28.5 million from the sales of 815,416 common shares, after commissions and other fees, under the Distribution Agreement. During the three months ended December 31, 2012, we sold no shares.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 22,789 and 2,750 during the years ended December 31, 2012 and 2011, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Sch. 19	MONTANA PLANT IN SERVICE - PROPANE			
	Account Number & Title	This Year Utility	Last Year Utility	% Change
1	**Local Storage Plant**			
2	3360 Land and Land Rights	$ 64,954	$ 64,954	0.00%
3	3363 Other Equipment	381,748	381,748	0.00%
4	**Total Local Storage Plant**	446,702	446,702	0.00%
5				
6	**Distribution Plant**			
7	3376 Mains	490,965	490,965	0.00%
8	3380 Services	493,066	493,066	0.00%
9	3381 Customers Meters and Regulators	33,429	33,429	0.00%
10	3382 Meter Installations			-
11	3389 Other Equipment	51,888	51,888	0.00%
12	**Total Distribution Plant**	1,069,348	1,069,348	0.00%
13	**Total Propane Plant in Service**	1,516,050	1,516,050	0.00%
14				
15	3107 Construction Work in Progress	-	-	-
16	3117 Gas in Underground Storage	20,560	23,095	-10.98%
17				
18				
19	**TOTAL PROPANE PLANT**	$ 1,536,610	$ 1,539,145	-0.16%
20				
21				
22	**CONSOLIDATED**	December 31,		
23	**PLANT IN SERVICE**	2012	2011	
24				
25	Montana Electric	$ 2,316,701,843	$ 2,167,521,871	
26	Yellowstone National Park	13,592,613	13,176,795	
27	Montana Natural Gas (Includes CMP)	605,723,287	562,889,531	
28	Common	84,766,822	79,977,860	
29	Townsend Propane	1,516,050	1,516,050	
30	South Dakota Electric	492,604,252	460,538,538	
31	South Dakota Natural Gas	157,452,886	150,503,744	
32	South Dakota Common	44,774,141	39,317,330	
33	Asset Retirement Obligation	6,376,126	3,910,360	
34	**TOTAL PLANT**	$ 3,723,508,020	$ 3,479,352,079	

Sch. 20	MONTANA DEPRECIATION SUMMARY - PROPANE				
	Functional Plant Class	Plant Cost	This Year	Last Year	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Local Storage Plant	$ 381,748	$ 223,905	$ 215,163	2.29%
4					
5	Distribution	1,069,348	468,087	433,802	3.24%
6					
7					
8	**Total Accumulated Depreciation**	$1,451,096.00	$ 691,992.00	$ 648,965.00	
9					
10					
11					
12					

13	**Consolidated**	December 31,	
14	**Accumulated Depreciation**	2012	2011
15			
16	Montana Electric	$ 901,894,297	$ 838,458,857
17	Yellowstone National Park	8,955,866	8,644,902
18	Montana Natural Gas (Includes CMP)	238,893,971	228,357,798
19	Common	36,018,027	33,478,642
20	Townsend Propane	691,992	648,965
21	South Dakota Electric	254,603,383	249,041,748
22	South Dakota Natural Gas	68,599,519	64,714,374
23	South Dakota Common	12,389,577	11,240,646
24	Acquisition Writedown	66,471,868	73,854,295
25	Basin Creek Capital Lease	13,068,062	11,057,582
26	FIN 47	1,252,831	1,092,090
27	CWIP-Capital Retirement Clearing	-4,589,625	-4,550,706
28	**Total Consolidated Accum Depreciation**	$ 1,598,249,768	$ 1,516,039,193

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - PROPANE			
	Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
	Docket Number: 2009.9.129			
	Order Number : 7046h			
	Common Equity	48.00%	10.25%	4.92%
	Long Term Debt	52.00%	5.76%	3.00%
	TOTAL	100.00%		7.92%

1/ Docket 2009.9.129, Order 7046h specifies the authorized capital structure and associated costs for the regulated gas utility effective December 9, 2010.

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 98,406,342	$ 92,555,872	6.32%
4	Noncash Charges (Credits) to Income:			
5	Depreciation	107,677,003	102,754,939	4.79%
6	Amortization, Net	(1,676,537)	(1,872,457)	10.46%
7	Other Noncash Charges to Net Income, Net	(40,823,868)	8,895,186	>-300.00%
8	Deferred Income Taxes, Net	65,871,867	59,551,081	10.61%
9	Investment Tax Credit Adjustments, Net	(375,635)	(423,561)	11.32%
10	Change in Operating Receivables, Net	7,549,047	9,880,617	-23.60%
11	Change in Materials, Supplies & Inventories, Net	5,367,735	(8,830,208)	160.79%
12	Change in Operating Payables & Accrued Liabilities, Net	21,727,054	(10,725,579)	>300.00%
13	Allowance for Funds Used During Construction (AFUDC)	(4,846,070)	(1,876,583)	-158.24%
14	Change in Other Assets & Liabilities, Net	13,109,501	1,734,801	>300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	10,657,063	(510,094)	>300.00%
17	Change in Regulatory Assets	(34,461,811)	(29,541,321)	-16.66%
18	Change in Regulatory Liabilities	(780,115)	5,587,054	-113.96%
19	**Net Cash Provided by Operating Activities**	247,401,576	227,179,747	8.90%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(322,474,752)	(188,730,360)	-70.87%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	261,793	209,396	25.02%
24	**Net Cash Used in Investing Activities**	(322,212,959)	(188,520,964)	-70.92%
25	**Cash Flows from Financing Activities:**			
26	Proceeds from Issuance of:			
27	Issuance of Long-Term Debt	150,000,000	-	100.00%
28	Credit Facilities Borrowings	-	80,000,000	-100.00%
29	Issuance of Short Term Borrowings, Net	-	166,933,493	-100.00%
30	Proceeds From Issuance of Common Stock, Net	28,477,203	-	100.00%
31	Payments for Retirement of:			
32	Credit Facilities Repayments	-	(233,000,000)	100.00%
33	Capital Lease Obligations, Net	(153,358)	(11,079)	>-300.00%
34	Repayments of Short Term Borrowings, Net	(43,999,590)	-	100.00%
35	Dividends on Common Stock	(54,245,888)	(51,909,137)	-4.50%
36	Other Financing Activities:			
37	Debt Financing Costs	(943,014)	(1,130,557)	16.59%
38	Treasury Stock Activity	(429,673)	154,223	>-300.00%
39	**Net Cash Provided by/(Used in) Financing Activities**	78,705,680	(38,963,057)	>300.00%
40	**Net Increase/(Decrease) in Cash and Cash Equivalents**	3,894,297	(304,274)	>300.00%
41	**Cash and Cash Equivalents at Beginning of Year**	5,927,817	6,232,091	-4.88%
42	**Cash and Cash Equivalents at End of Year**	$ 9,822,114	$ 5,927,817	65.70%
43				
44	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
45	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
46	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
47	Pipeline Corporation.			
48				

Sch. 24	MONTANA LONG TERM DEBT 1/								
	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
3	6.34% Series, Due 2019	03/26/09	04/01/19	$250,000,000	$247,657,313	$249,895,312	6.340%	$16,514,170	6.61%
4	5.71% Series, Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.710%	3,158,845	5.74%
5	6.04% Series, Due 2016	09/13/06	09/01/16	150,000,000	148,302,298	149,973,050	6.040%	9,308,114	6.21%
6	5.01% Series, Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	161,000,000	5.010%	8,585,842	5.33%
7	4.15% Series, Due 2042	08/10/12	08/10/42	60,000,000	59,623,329	60,000,000	4.150%	2,502,562	4.17%
8	4.30% Series, Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.300%	1,726,280	4.32%
9	**Total First Mortgage Bonds**			$716,000,000	$709,857,461	$715,868,362		$41,795,813	5.84%
10									
11	**Pollution Control Bonds**								
12	4.65% Series, Due 2023	04/27/06	08/01/23	$170,205,000	$164,451,956	$170,205,000	4.650%	$8,467,855	4.98%
13									
14	**Total Pollution Control Bonds**			$170,205,000	$164,451,956	$170,205,000		$8,467,855	4.98%
15									
16	**TOTAL LONG TERM DEBT**			$886,205,000	$874,309,417	$886,073,362		$50,263,668	5.67%

This schedule does not reflect capital leases, which are comprixed of Fleet Leases and the Basin Creek contract. These amounts total $256,158 and $32,917,879, respectively.

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	NOT APPLICABLE									
3										
4										
5										
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26										
27										
28										
29										
30										
31										
32	TOTAL									

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	36,281,644	$24.01				$36.39	$34.36	
February	36,345,920	24.28				35.93	34.63	
March	36,385,268	24.18	$0.88	$0.37		35.82	34.22	
April	36,390,258	24.31				36.05	33.72	
May	36,783,569	24.45				35.85	34.47	
June	37,081,672	24.30	0.31	0.37		37.05	34.80	
July	37,202,374	24.50				37.96	36.08	
August	37,205,154	24.73				37.35	35.66	
September	37,214,807	23.88	(0.10)	0.37		37.65	35.44	
October	37,215,556	24.96				36.70	34.91	
November	37,219,313	25.25				36.09	32.98	
December	37,221,344	25.09	1.58	0.37		35.73	33.98	
TOTAL Year End	36,847,427	$25.09	$2.67	$1.48	44.57%	$34.73		13.0

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2012.

Sch. 27	MONTANA EARNED RATE OF RETURN - PROPANE			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$1,516,050	$1,514,514	0.10%
3	108 Accumulated Depreciation	(670,649)	(627,328)	-6.91%
4				
5	**Net Plant in Service**	$845,401	$887,186	-4.71%
6	Additions:			
7	Other Additions	$30,841	$32,160	-4.10%
8				
9	**Total Additions**	$30,841	$32,160	-4.10%
10	Deductions:			
11	190 Accumulated Deferred Income Taxes	$71,389	$25,546	179.45%
12				
13	**Total Deductions**	$71,389	$25,546	179.45%
14	**Total Rate Base**	$804,853	$893,800	-9.95%
15	**Net Earnings**	($40,784)	($6,053)	>-300.00%
16	**Rate of Return on Average Rate Base**	-5.067%	-0.677%	>-300.00%
17	**Rate of Return on Average Equity**	Not applicable	Not applicable	
18				
19	**Major Normalizing and**			
20	**Commission Ratemaking Adjustments**			
21				
22				
23		None		
24				
25				
26				
27				
28				
29	**Total Adjustments**			
30	**Revised Net Earnings**			
31	**Adjusted Rate of Return on Average Rate Base**			
32	**Adjusted Rate of Return on Average Equity**			
33				
34	**Detail - Other Additions**			
35	Propane on Hand	$30,841	$32,160	-4.10%
36				
37	**Total Other Additions**	$30,841	$32,160	-4.10%
38				
39	**Detail - Other Deductions**			
40				
41	**Total Other Deductions**	-	-	-
42				
43				
44				
45				
46				

Sch. 28	MONTANA COMPOSITE STATISTICS - PROPANE		
		Description	Amount
1			
2		**Plant**	
3			
4	101	Plant in Service	$ 1,516,050
5	107	Construction Work in Progress	
6	117	Gas in Underground Storage	20,560
7	108, 111	Depreciation & Amortization Reserves	691,992
8			
9	**NET BOOK COSTS**		844,618
10			
11		**Revenues & Expenses**	
12			
13	400	Operating Revenues	863,090
14			
15	**Total Operating Revenues**		863,090
16			
17	401-402	Operation & Maintenance Expenses	821,117
18	403-407	Depreciation Expense	43,367
19	408.1	Taxes Other than Income Taxes	59,095
20	409-411	Federal & State Income Taxes	(19,705)
21			
22	**Total Operating Expenses**		903,874
23	**Net Operating Income**		(40,784)
24			
25	415-421.1	Other Income	-
26	421.2-426.5	Other Deductions	-
27	**NET INCOME BEFORE INTEREST EXPENSE**		$ (40,784)
28			
29		**Average Customers**	
30		Residential	502
31		Commercial / Industrial	70
32			
33	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		572
34			
35		**Other Statistics**	
36		Average Annual Residential Use (Dkt)	47.2
37		Average Annual Residential Cost per (Dkt)	$23.63
38		Average Residential Monthly Bill	$92.88
39			
40		Plant in Service (Gross) per Customer	$2,650

Sch. 29	Montana Customer Information- Propane, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Townsend	1,878	502	70	-	572
2						
3						
4						
5						
6						
7						
8						
9	**Total**	1,878	502	70	-	572
10						
11						
12	1/ Customer populations represent an average of the 12 month period from 01/01/12 through 12/31/12.					

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	109	106	108
5	Finance	123	128	126
6	Regulatory Affairs	27	29	28
7	Distribution	549	583	566
8	Transmission	201	197	199
9	Supply	32	31	32
10	Legal	12	16	14
11				
12				
13				
14				
15				
16				
17				
18	**TOTAL EMPLOYEES**	1,055	1,092	1,074

1/ Consistent with prior years, part time employees have been converted to full-time equivalents.

Sch. 31	MONTANA CONSTRUCTION BUDGET 2013 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Elec Trans - Crooked Falls Switch Yard	$1,898,568	$1,898,568
4	MT Elec Trans - 161kV Breaker Ring Bus	2,064,443	2,064,443
5	MT Elec Trans - Jack-Rabbit-Big Sky 161kV Line	12,587,065	12,587,065
6	MT Elec Trans - Columbus-Rapelje to Chrome Jct 100 kV line	2,331,225	2,331,225
7	MT Elec Distribution - Elec Distribution Infrastructure Plan	44,871,666	44,871,666
8	MT Elec Distribution - Billings 8th Street Sub Ringbus	1,706,777	1,706,777
9	SD Elec Trans - Yankton East Substation	3,048,058	
10	SD Elec Redfield to Broadland 115kV	5,073,432	
9			
10	All Other Projects < $1 Million Each MT	49,372,262	49,372,262
11	All Other Projects < $1 Million Each SD	15,556,282	
12	**Total Electric Utility Construction Budget**	$138,509,778	$114,832,006
13			
14	**Natural Gas Operations**		
15	MT Gas Retail - Gas Distribution Infrastructure Plan	8,028,943	8,028,943
16	MT Gas Trans - Pipeline Integrity Mgmt - Green Meadow Golf	1,697,296	1,697,296
17	MT Gas Trans - Pipeline Integrity Mgmt - Other HCA projects	1,295,968	1,295,968
18			
19	All Other Projects < $1 Million Each MT	14,212,070	14,212,070
20	All Other Projects < $1 Million Each SD NE	4,699,171	
21	**Total Natural Gas Utility Construction Budget**	29,933,448	25,234,277
22			
23	**Common**		
24	Fleet and Equipment Purchases	6,000,000	4,261,000
25	BT CIS Upgrade and Consolidation	2,693,704	2,058,969
26	IT AM-FM GIS system	1,254,984	1,091,836
27			
28			
29	All Other Projects < $1 Million Each MT	4,626,219	4,626,219
30	(Includes IT, Communications, Facilities, Cust Serv)		
31	All Other Projects < $1 Million Each SD NE	1,733,980	
32			
33	**Total Common Utility Construction Budget**	16,308,887	12,038,024
34			
35	MT CU4 capital additions - PPL invoice	6,461,700	6,461,700
36			
37	SD Big Stone, Neal 4, Coyote partner capital	1,629,517	
38	SD Internal Generation - RICE NESHAP Compliance	3,825,938	
39			
40	All Other Projects < $1 Million Each MT	797,030	797,030
41	All Other Projects < $1 Million Each SD	1,314,309	
42	**Total MT/SD Generation**	14,028,494	7,258,730
43	**TOTAL CONSTRUCTION BUDGET**	$198,780,607	$159,363,037

Sch. 33	MONTANA SOURCES OF PROPANE SUPPLY				
		Dekatherm Volumes		Avg. Commodity Cost	
		2012 Year	2011 Year	2012 Year	2011 Year
1	**Name of Supplier**				
2					
3	AmeriGas	20,616	44,545	$17.3774	$16.1018
4	Gibson Energy, LLC	17,633		$11.6206	
5					
6	**Total Propane Supply Volumes**	38,249	44,545	$14.7235	$16.1018

Sch. 35	MONTANA CONSUMPTION AND REVENUES - PROPANE						
		Operating Revenues		Dkt Sold		Average Customers	
		2012 Year	2011 Year	2012 Year	2011 Year	2012 Year	2011 Year
1	**Sales of Propane**						
2							
3	Residential	$559,511	$632,290	23,681	28,687	502	507
4	Commercial / Industrial	303,579	296,259	13,174	13,602	70	71
5							
6							
7	TOTAL SALES	$863,090	$928,549	36,855	42,289	572	578