MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

January 25, 2013

Ms. Kate Whitney, Administrator
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620

Re: General Gas Rate Application
Docket No. D2012.9.100

Dear Ms. Whitney:

Enclosed please find Montana-Dakota Utilities Co.'s responses to the Montana Public Service Commission data requests dated January 8, 2013, and January 18, 2013. Responses to the following requests are attached:

PSC-042	PSC-066
PSC-043	PSC-067
PSC-044	PSC-095
PSC-045	PSC-104
PSC-046	PSC-137
PSC-049	PSC-146

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachments
cc: Service List

Montana-Dakota Utilities Co.
Docket No. D2012.9.100
Service List

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Montana Public Service Commission
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MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC-042

Regarding: Real properties
Witness: Applicable Witness

a. Please list for all properties that are included in regulated rate base that are not being used for regulated purposes, a property description, original cost book value, depreciation, net book value, and market value, if known.

b. Please list all properties that are obsolete, listed to be disposed of, or presently being disposed of, the carrying value of the property, status (whether sold or not), and selling price.

c. Please provide for all disposed of properties since 2008, a property description, original cost book value, depreciation, net book value, and selling price.

Response:

a-c. Please see Response No. PSC-025.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC-043

Regarding: Year-end departmental summary expense statements and balance sheets
Witness: Applicable Witness

For the years 2010 and 2011 please provide copies of MDU's year-end departmental summary expense statements and balance sheets.

Response:

Please see Attachment A for the 2010 and 2011 summary expenses.

Response No. PSC-043
Attachment A

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
711R: Customer Services Rollup		
5110: Straight Time/Total Payroll	1,671,511	1,677,513
5120: Premium Time	39,999	45,233
5130: Bonuses & Commissions	50,918	85,412
5131: Bonuses & Commissions	129,252	125,239
5140: Moving Allowance	1,092	
5150: Taxable Meals		23
5192: Other Benefits	5,957	5,895
5193: Vacation		
5194: Medical/Dental	333,043	355,831
5195: Pension	21,711	15,650
5196: Post Retirement	19,806	17,533
5197: 401-K	174,988	138,249
5199: Workers Comp.	3,948	3,527
5211: Subcontract Labor	10,535	15,681
5221: Consulting Fees		
5292: Custodial Services	8,205	10,292
5293: Collection Agency Fees	143,268	183,560
5410: Company Vehicles	902	803
5511: Commercial Air Service	10,247	7,541
5512: Corporate Aircraft		
5514: Personal Vehicle Use	47	19
5521: Meals & Entertainment	6,498	11,051
5522: Other Reimburseable Exp.	10,488	5,052
5610: Telephone	49,557	81,768
5611: Cell phone	718	2,596
5612: Network circuit		
5630: Office Supplies	9,413	10,683
5640: Utilities	10,113	10,187
5651: Postage	3,090	5,518
5715: Other Utility Advertising		59,288
5811: Professional Organ. Dues	137	275
5812: College Tuition & Books	1,721	1,407
5813: Miscellaneous	8,695	14,212
5851: Seminars & Meeting Reg.	2,255	1,756
5853: Safety Training Materials &	333	
5854: Other Employee Training	771	3,673
5911: Software Maintenance	20,678	41,412
5912: Company Organizational Dues		
5913: Permits & Filing Fees	150	
5931: Building & Sign Rental	273,049	352,096
5982: Reference Material	16	32
5997: Credit Card Accrual		
Total: 711R	3,023,111	3,289,007
723R: Information Tech Rollup		
5110: Straight Time/Total Payroll	1,825,652	1,596,783

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5120: Premium Time	33,089	33,571
5130: Bonuses & Commissions	2,788	2,866
5131: Bonuses & Commissions	130,872	111,275
5140: Moving Allowance	6,800	890
5150: Taxable Meals	638	1,015
5192: Other Benefits	5,877	5,277
5194: Medical/Dental	181,269	165,992
5195: Pension	39,630	53,406
5196: Post Retirement	33,704	42,507
5197: 401-K	217,486	181,459
5199: Workers Comp.	2,496	2,059
5211: Subcontract Labor	239,092	238,773
5221: Consulting Fees		3,181
5292: Custodial Services	21	
5300: Materials	57,636	86,405
5410: Company Vehicles	19,108	20,319
5421: Company Work Equipment	239	282
5511: Commercial Air Service	28,898	11,101
5512: Corporate Aircraft	2,272	1,304
5514: Personal Vehicle Use	1,922	1,513
5521: Meals & Entertainment	12,051	9,474
5522: Other Reimburseable Exp.	35,418	24,199
5610: Telephone	438,551	410,345
5611: Cell phone	64,779	95,101
5612: Network circuit	278,608	287,219
5613: SCADA/EMS circuit	465,535	363,031
5614: Other circuits	79,832	65,981
5620: Photocopier	19	
5630: Office Supplies	64,867	47,362
5640: Utilities	8,000	8,549
5641: Company Consumption - Elec	10,597	10,305
5642: Company Consumption - Gas	492	549
5651: Postage	22	8
5811: Professional Organ. Dues	1,072	1,904
5812: College Tuition & Books	3,466	
5813: Miscellaneous	844	8,826
5851: Seminars & Meeting Reg.	8,530	12,149
5853: Safety Training Materials &		30
5854: Other Employee Training	54	1,026
5911: Software Maintenance	831,414	868,155
5912: Company Organizational Dues	3,565	4,348
5913: Permits & Filing Fees	8,729	4,014
5931: Building & Sign Rental	115,826	146,769
5932: Annual Easements	17,177	14,439
5934: Computer Rental	88,437	55,539
5941: Reimbursements		(622)
5950: Freight	477	503
5982: Reference Material	643	728

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5997: Credit Card Accrual		
Total: 723R	5,368,494	4,999,908
890R: VP Electric Energy Supply Rollup		
5110: Straight Time/Total Payroll	8,351,017	8,769,619
5120: Premium Time	789,646	832,573
5130: Bonuses & Commissions	25,295	38,369
5131: Bonuses & Commissions	822,754	632,577
5140: Moving Allowance		5,785
5150: Taxable Meals	11,065	4,939
5192: Other Benefits	38,462	44,867
5193: Vacation	62,815	53,210
5194: Medical/Dental	1,055,342	1,137,674
5195: Pension	145,822	306,025
5196: Post Retirement	168,428	247,460
5197: 401-K	837,627	1,080,782
5199: Workers Comp.	47,463	62,790
5211: Subcontract Labor	6,185,276	6,246,865
5212: Compressor Station		
5221: Consulting Fees	111,687	17,817
5222: Legal Fees		80
5250: Big Stone Station Exp.	2,574,539	3,593,021
5260: Coyote Station Expenses	4,294,495	4,679,196
5270: WYGEN	1,388,598	2,232,670
5292: Custodial Services	52,486	52,821
5300: Materials	2,786,661	2,297,598
5311: Natural Gas	28,640	27,170
5331: Sand	406,218	431,278
5332: Sulpher Reagent		19,113
5410: Company Vehicles	331,419	267,152
5421: Company Work Equipment	116,719	83,868
5422: Rental Work Equipment	78,677	109,796
5511: Commercial Air Service	40,414	37,072
5512: Corporate Aircraft	7,211	14,458
5513: Corporate Aircraft - Undist.		
5514: Personal Vehicle Use	10,204	8,906
5521: Meals & Entertainment	45,919	69,437
5522: Other Reimburseable Exp.	77,030	85,422
5610: Telephone	(99,493)	(100,093)
5611: Cell phone	17,340	19,086
5612: Network circuit	12,360	15,450
5613: SCADA/EMS circuit	24,514	19,257
5614: Other circuits	1,857	3,407
5620: Photocopier	1,099	2,469
5630: Office Supplies	41,820	38,307
5640: Utilities	4,926	4,888
5641: Company Consumption - Elec	13,839	16,515

RC / Resource	Budget Actuals 2010_Total	2011_Total
5642: Company Consumption - Gas	30,104	40,734
5651: Postage	2,429	1,843
5652: Express Mail	227	411
5661: Rental of Office Equipment	7,190	6,920
5711: Radio Advertising	245	
5712: Newspaper Advertising	150	745
5713: Television Advertising	300	
5715: Other Utility Advertising	3,253	1,814
5740: Public Information Meetings		
5811: Professional Organ. Dues	18,388	17,488
5812: College Tuition & Books	3,744	713
5813: Miscellaneous	22,476	24,218
5830: Employee Meetings	80	
5851: Seminars & Meeting Reg.	44,737	90,054
5853: Safety Training Materials &	60,235	59,804
5854: Other Employee Training	749	47,130
5891: Uniforms	5,924	7,468
5911: Software Maintenance	219,868	210,521
5912: Company Organizational Dues	5,500	17,000
5913: Permits & Filing Fees	191,425	166,757
5931: Building & Sign Rental	309,289	385,314
5932: Annual Easements	70,568	135,304
5935: Facility Charge	1,528,271	1,543,476
5941: Reimbursements	(392,047)	(70,862)
5950: Freight	62,466	18,831
5981: Cash Donations		
5982: Reference Material	2,441	3,212
5984: Damage Payment	22,807	8,426
5985: Inventory Shrinkage	2,701	(301)
5987: Research & Development	1,553	
5997: Credit Card Accrual	20	
Total: 890R	33,135,283	36,226,714
918R: EVP Gas Supply, Regulatory & Bus Dev		
5110: Straight Time/Total Payroll	770,514	768,138
5120: Premium Time	856	19
5130: Bonuses & Commissions		451
5131: Bonuses & Commissions	112,526	106,172
5150: Taxable Meals	136	90
5192: Other Benefits	2,734	2,833
5194: Medical/Dental	82,868	80,794
5195: Pension	18,692	30,248
5196: Post Retirement	15,423	21,735
5197: 401-K	103,155	99,212
5199: Workers Comp.	695	1,463
5211: Subcontract Labor	7,550	14,088
5221: Consulting Fees	18,402	

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5300: Materials		
5410: Company Vehicles	6,285	5,962
5511: Commercial Air Service	17,607	19,502
5512: Corporate Aircraft	1,771	8,831
5514: Personal Vehicle Use	1,118	751
5521: Meals & Entertainment	6,633	6,733
5522: Other Reimburseable Exp.	16,281	13,729
5611: Cell phone	4,387	6,835
5630: Office Supplies	4,074	2,988
5711: Radio Advertising		
5712: Newspaper Advertising	250	250
5713: Television Advertising		
5715: Other Utility Advertising	23,135	26,614
5731: Marketing Incentives	217,660	195,538
5732: Economic Development	5,500	2,500
5811: Professional Organ. Dues	4,174	3,105
5812: College Tuition & Books		1,965
5813: Miscellaneous	898	1,746
5851: Seminars & Meeting Reg.	5,247	2,784
5854: Other Employee Training		
5911: Software Maintenance	38,553	8,360
5912: Company Organizational Dues	28,963	53,347
5913: Permits & Filing Fees	6,951	7,082
5982: Reference Material	15,944	36,814
5997: Credit Card Accrual		
Total: 918R	1,538,981	1,530,680
919: V.P. Utility Group		
5110: Straight Time/Total Payroll	103,450	68,000
5130: Bonuses & Commissions	49,270	(25,404)
5131: Bonuses & Commissions	31,742	30,600
5140: Moving Allowance		19,497
5192: Other Benefits	132	
5194: Medical/Dental	5,539	3,041
5196: Post Retirement	2,046	2,109
5197: 401-K	8,269	5,440
5199: Workers Comp.	174	43
5221: Consulting Fees		2,153
5410: Company Vehicles	154	85
5511: Commercial Air Service	5,002	2,034
5512: Corporate Aircraft		1,756
5514: Personal Vehicle Use	83	
5521: Meals & Entertainment	2,686	553
5522: Other Reimburseable Exp.	3,959	996
5611: Cell phone		397
5630: Office Supplies	53	42
5652: Express Mail	13	

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5811: Professional Organ. Dues		26
5813: Miscellaneous	23	
5820: Moving Expenses	3,979	6,938
5851: Seminars & Meeting Reg.	31	
5982: Reference Material	1	
Total: 919	216,604	118,308
941R: VP Controller & CAO Rollup		
5110: Straight Time/Total Payroll	1,980,972	2,258,655
5120: Premium Time	19,377	35,235
5130: Bonuses & Commissions	7,963	3,590
5131: Bonuses & Commissions	137,047	(315,817)
5140: Moving Allowance	15,000	
5150: Taxable Meals	44	121
5192: Other Benefits	16,969	14,483
5193: Vacation	157,454	125,003
5194: Medical/Dental	214,911	244,526
5195: Pension	(45,633)	27,776
5196: Post Retirement	5,915	19,583
5197: 401-K	277,945	238,098
5199: Workers Comp.	24,235	10,367
5200: Contract Services		5,193
5211: Subcontract Labor	174,418	266,232
5221: Consulting Fees	9,677	26,736
5222: Legal Fees	337,499	185,973
5223: External Auditing	202,631	168,284
5400: Company Vehicles & Work Equi		
5410: Company Vehicles	(2,788)	20,451
5511: Commercial Air Service	5,205	8,874
5512: Corporate Aircraft	2,483	15,454
5514: Personal Vehicle Use	257	1,568
5521: Meals & Entertainment	6,405	10,236
5522: Other Reimburseable Exp.	7,453	26,308
5611: Cell phone	2,093	2,164
5630: Office Supplies	425,360	435,101
5715: Other Utility Advertising		
5811: Professional Organ. Dues	1,456	1,719
5813: Miscellaneous	1,194	6,318
5851: Seminars & Meeting Reg.	8,042	29,513
5854: Other Employee Training	6,578	2,034
5910: Fees, Permits, Dues & Licens		86,905
5911: Software Maintenance	37,125	16,613
5912: Company Organizational Dues	200	250
5913: Permits & Filing Fees	203,202	225,906
5914: Bank Service Fees	229,705	237,293
5922: Prepaid Insurance Amortizati	2,470,309	2,150,116
5931: Building & Sign Rental	579,931	262,559

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5941: Reimbursements	(153,778)	(845)
5960: Uncollectible Accounts		1,008,190
5982: Reference Material	14,557	14,688
5983: Deferred Charge Amortization	246,148	628,464
5997: Credit Card Accrual		
Total: 941R	7,627,557	8,503,917
960R: VP Operations Rollup		
5110: Straight Time/Total Payroll	20,971,844	21,352,128
5120: Premium Time	1,967,948	2,610,582
5130: Bonuses & Commissions	112,249	419,130
5131: Bonuses & Commissions	1,700,968	1,156,325
5140: Moving Allowance	51,045	106,643
5150: Taxable Meals	80,125	41,213
5192: Other Benefits	83,712	92,705
5193: Vacation	227,943	188,856
5194: Medical/Dental	2,581,701	2,622,792
5195: Pension	250,470	670,673
5196: Post Retirement	333,721	487,458
5197: 401-K	1,584,735	2,195,165
5199: Workers Comp.	131,208	190,735
5200: Contract Services	397,122	418,381
5211: Subcontract Labor	2,758,069	3,319,579
5212: Compressor Station		
5221: Consulting Fees		6,058
5222: Legal Fees		
5292: Custodial Services	201,694	205,567
5293: Collection Agency Fees	23,531	
5300: Materials	1,881,463	2,216,552
5400: Company Vehicles & Work Equi	184,146	214,677
5410: Company Vehicles	2,217,907	2,666,838
5421: Company Work Equipment	371,718	456,682
5422: Rental Work Equipment	6,421	21,993
5511: Commercial Air Service	14,430	22,483
5512: Corporate Aircraft	4,204	8,719
5514: Personal Vehicle Use	11,241	8,340
5521: Meals & Entertainment	94,141	97,947
5522: Other Reimburseable Exp.	147,875	202,687
5600: Office Expenses	272,758	284,029
5610: Telephone	195,709	183,933
5611: Cell phone	144,125	147,071
5612: Network circuit	86,520	89,610
5614: Other circuits	13,509	12,058
5620: Photocopier	43,274	41,804
5630: Office Supplies	101,993	105,950
5640: Utilities	175,981	727,071
5641: Company Consumption - Elec	227,283	241,454

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5642: Company Consumption - Gas	226,787	236,722
5651: Postage	93,821	55,527
5652: Express Mail	10	34
5661: Rental of Office Equipment	35,453	40,606
5710: Advertising - Utility	31,880	24,306
5711: Radio Advertising	45,964	55,197
5712: Newspaper Advertising	20,332	21,368
5713: Television Advertising	60,342	32,055
5715: Other Utility Advertising	159,174	201,128
5731: Marketing Incentives		
5732: Economic Development		
5740: Public Information Meetings	7,634	2,797
5810: Employee Benefits	7,876	9,147
5811: Professional Organ. Dues	3,626	4,743
5812: College Tuition & Books	82	3,804
5813: Miscellaneous	60,073	74,829
5815: Utility Discounts	252	239
5820: Moving Expenses	38,777	94,217
5830: Employee Meetings	3,264	
5850: Employee Training	3,822	4,724
5851: Seminars & Meeting Reg.	20,947	23,859
5853: Safety Training Materials &	83,280	71,412
5854: Other Employee Training	3,285	4,026
5891: Uniforms	92,982	73,380
5910: Fees, Permits, Dues & Licens	121,766	51,584
5911: Software Maintenance	25,345	23,366
5912: Company Organizational Dues	82,477	76,783
5913: Permits & Filing Fees	24,988	23,640
5914: Bank Service Fees	14,065	12,956
5930: Rent	23,790	23,724
5931: Building & Sign Rental	254,021	177,288
5932: Annual Easements	42,710	43,042
5933: Leasehold Improvements	2,444	
5935: Facility Charge	34,114	32,903
5940: Reimbursements & Other Credi	(17,476)	(17,971)
5941: Reimbursements	(663,200)	(703,661)
5943: Capital Installation Credits	(1,449,901)	(1,812,868)
5950: Freight	61,335	78,710
5960: Uncollectible Accounts	876,914	107,938
5982: Reference Material	7,883	7,941
5984: Damage Payment	14,203	9,462
5985: Inventory Shrinkage	18,481	12,352
5988: Cathodic Protection	138,767	121,632
5997: Credit Card Accrual		
Total: 960R	40,265,174	43,136,829
961R: Fleet and Procurement Dept		

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5110: Straight Time/Total Payroll	718,880	718,117
5120: Premium Time	19,820	14,127
5130: Bonuses & Commissions	1,350	3,131
5131: Bonuses & Commissions	53,648	50,738
5150: Taxable Meals	40	
5192: Other Benefits	2,461	2,487
5194: Medical/Dental	88,309	91,413
5195: Pension	16,789	29,829
5196: Post Retirement	12,951	20,267
5197: 401-K	96,912	96,916
5199: Workers Comp.	3,438	2,981
5211: Subcontract Labor	332,585	317,124
5221: Consulting Fees	2,400	
5292: Custodial Services	103,865	110,313
5300: Materials	20,505	30,993
5410: Company Vehicles	978	1,577
5511: Commercial Air Service	880	3,649
5512: Corporate Aircraft	156	
5514: Personal Vehicle Use		
5521: Meals & Entertainment	998	1,554
5522: Other Reimburseable Exp.	1,660	3,093
5611: Cell phone	1,181	1,207
5620: Photocopier	185,154	174,042
5630: Office Supplies	868,454	797,970
5640: Utilities	5,638	8,049
5641: Company Consumption - Elec	164,474	182,249
5642: Company Consumption - Gas	59,891	68,676
5651: Postage	1,373,295	1,652,361
5652: Express Mail	42,777	42,466
5661: Rental of Office Equipment	3,120	3,220
5811: Professional Organ. Dues	987	1,352
5812: College Tuition & Books		
5813: Miscellaneous		2,042
5830: Employee Meetings	1,323	
5851: Seminars & Meeting Reg.	1,537	3,591
5853: Safety Training Materials &		
5854: Other Employee Training	40	167
5891: Uniforms	583	532
5913: Permits & Filing Fees	40	125
5931: Building & Sign Rental	47,576	49,324
5950: Freight		
5982: Reference Material	1,352	1,342
5997: Credit Card Accrual		
Total: 961R	4,236,047	4,487,023
963R: VP Human Resources		
5110: Straight Time/Total Payroll	1,187,457	1,169,924

RC / Resource	Budget Actuals 2010_Total	2011_Total
5120: Premium Time	2,954	2,283
5130: Bonuses & Commissions	185,229	10,000
5131: Bonuses & Commissions	89,379	83,526
5150: Taxable Meals	168	270
5192: Other Benefits	4,149	4,052
5194: Medical/Dental	120,655	104,144
5195: Pension	27,756	40,845
5196: Post Retirement	78,188	87,068
5197: 401-K	161,983	134,519
5199: Workers Comp.	2,273	2,082
5211: Subcontract Labor	31,232	37,928
5221: Consulting Fees	1,875	29,300
5300: Materials	1,630	1,660
5410: Company Vehicles	50,704	57,477
5511: Commercial Air Service	16,511	16,905
5512: Corporate Aircraft	1,954	690
5514: Personal Vehicle Use	3,931	3,492
5521: Meals & Entertainment	30,255	29,830
5522: Other Reimburseable Exp.	45,558	53,678
5611: Cell phone	7,674	10,784
5630: Office Supplies	5,512	9,938
5651: Postage	16	106
5811: Professional Organ. Dues	4,385	3,622
5812: College Tuition & Books	46,394	27,936
5813: Miscellaneous	79,817	82,236
5814: Merchandise Discounts	10,872	10,072
5815: Utility Discounts	299,498	265,488
5820: Moving Expenses		
5830: Employee Meetings		350
5851: Seminars & Meeting Reg.	14,984	14,203
5853: Safety Training Materials &	23,522	28,726
5854: Other Employee Training	89,298	109,538
5911: Software Maintenance		
5913: Permits & Filing Fees	20	
5921: Supplemental Insurance	(1,600,840)	1,232,593
5950: Freight	83	53
5982: Reference Material	7,072	6,955
5997: Credit Card Accrual		
Total: 963R	1,032,149	3,672,275
985: Montana-Dakota President & CEO		
5110: Straight Time/Total Payroll	209,425	224,900
5120: Premium Time	355	1,008
5130: Bonuses & Commissions	226,127	379,348
5131: Bonuses & Commissions	373,329	117,455
5140: Moving Allowance		
5150: Taxable Meals	32	

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5192: Other Benefits	726	787
5194: Medical/Dental	60,400	11,886
5195: Pension	5,655	10,244
5196: Post Retirement	4,118	6,200
5197: 401-K	522,675	678,792
5199: Workers Comp.	180	277
5211: Subcontract Labor		
5410: Company Vehicles	923	277
5511: Commercial Air Service	11,599	3,497
5512: Corporate Aircraft	2,859	8,761
5514: Personal Vehicle Use	5	256
5521: Meals & Entertainment	2,695	5,870
5522: Other Reimburseable Exp.	6,302	4,844
5611: Cell phone	376	509
5630: Office Supplies	831	427
5715: Other Utility Advertising	22,500	49,300
5811: Professional Organ. Dues	104	181
5813: Miscellaneous	240	924
5830: Employee Meetings	2,029	
5851: Seminars & Meeting Reg.	1,337	1,103
5912: Company Organizational Dues	289,030	326,941
5913: Permits & Filing Fees		25
5982: Reference Material	666	551
5997: Credit Card Accrual		
Total: 985	1,744,518	1,834,364
994: MDU Resources Cross Charge		
5110: Straight Time/Total Payroll	1,895,110	1,997,446
5120: Premium Time	2,613	19,133
5130: Bonuses & Commissions	709,974	788,225
5140: Moving Allowance	1,450	780
5150: Taxable Meals	293	375
5192: Other Benefits	7,163	9,191
5193: Vacation	(5,279)	5,540
5194: Medical/Dental	178,909	184,089
5195: Pension	(32,315)	(33,992)
5196: Post Retirement	22,148	51,257
5197: 401-K	231,631	206,276
5199: Workers Comp.	1,682	2,079
5211: Subcontract Labor	254,295	237,497
5221: Consulting Fees	149,983	80,715
5222: Legal Fees	192,939	172,103
5223: External Auditing	24,502	27,227
5224: Investor Relations	8,702	9,275
5231: Active Directors Fees and Ex	151,332	294,903
5232: Retired Directors Fees and E	8,927	9,680
5233: Director's Meals and Enterta	3,780	3,744

RC / Resource	Budget Actuals 2010_Total	Budget Actuals 2011_Total
5410: Company Vehicles	1,619	4,267
5511: Commercial Air Service	9,670	9,919
5512: Corporate Aircraft	24,419	17,611
5514: Personal Vehicle Use	602	598
5521: Meals & Entertainment	10,528	12,646
5522: Other Reimburseable Exp.	18,452	21,648
5610: Telephone	22,877	21,764
5611: Cell phone	5,364	5,871
5630: Office Supplies	14,131	13,877
5651: Postage	3,056	3,269
5652: Express Mail	221	2
5661: Rental of Office Equipment		275
5715: Other Utility Advertising	23,926	59,958
5811: Professional Organ. Dues	5,138	3,930
5812: College Tuition & Books		987
5813: Miscellaneous	6,977	24,242
5814: Merchandise Discounts	57	44
5815: Utility Discounts	2,537	1,646
5830: Employee Meetings	22,107	20,948
5851: Seminars & Meeting Reg.	9,861	13,399
5852: Executive Training		
5853: Safety Training Materials &	29	26
5854: Other Employee Training	6,445	9,340
5911: Software Maintenance	82,099	89,370
5912: Company Organizational Dues	12,495	19,191
5913: Permits & Filing Fees	5,787	6,153
5914: Bank Service Fees	55,986	55,398
5921: Supplemental Insurance	(157,109)	446,860
5922: Prepaid Insurance Amortizati	192,356	170,214
5931: Building & Sign Rental	1,988	662
5934: Computer Rental	1,082	840
5941: Reimbursements	(6,825)	(8,291)
5942: Billed to Subsidiary Compani		
5950: Freight		
5982: Reference Material	28,450	29,553
Total: 994	4,212,166	5,121,760
Grand Total	**102,400,085**	**112,920,783**

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC-044

Regarding: Rate of Return, etc.
Witness: Applicable Witness

Please provide a copy of the testimony filed by MDU and the response testimony provided by intervenors on rate of return, cost of capital and capital structure in the two most recent rate applications for the jurisdictions MDU operates in other than Montana.

Response:

Please see Attachment A for the following testimony filed by Montana-Dakota on rate of return, cost of capital and capital structure and testimony provided by intervenors. The North Dakota Advocacy Staff did not file testimony in the 2010 North Dakota electric Case No. PU-10-124:

- Case No. PU-10-124 – North Dakota electric, 2010.
- Docket No. 20004-81-ER-09 – Wyoming electric, 2009.

Response No. PSC-044
Attachment A
North Dakota Case No. PU-10-124

Exhibit No.___(JSG-1)

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-10-____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1717 Rhode Island Avenue, Suite 630, Washington, DC 20036.

Q2. Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. Subsequently, I spent a year assisting in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988 I returned to H. Zinder & Associates ("HZA") and was President of the company from 2000 to 2008. In May 2008, HZA merged with Concentric Energy Advisors ("CEA") and I became a Senior Vice President of CEA.

Q3. Have you presented expert testimony in other proceedings?

A. Yes. I have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil and gas pipeline operations before ten state and provincial regulatory bodies, including the North Dakota Public Service Commission, and the Comisión Reguladora de Energia de México ("CRE"). I also have testified or filed testimony or affidavits before the Federal Energy Regulatory Commission on more than thirty occasions. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements and market power. In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing and generating plant economics before the U.S. Postal Rate Commission, the Alberta Energy and Utilities Board, the Ontario Energy Board, the New Brunswick Energy and Utilities Board and five state public utility Commissions. During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses. Finally, I am a member of the American Economic Association, the Financial Management Association, and the American Finance Association.

I. INTRODUCTION

A. Scope and Overview

Q4. What is the scope of your testimony in this proceeding?

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to estimate the cost of common equity capital for the Company's electric utility operations in the state of North Dakota. In this testimony, I calculate the cost of common equity capital for Montana-Dakota's electric utility operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Montana-Dakota's North Dakota electric utility operations. The results of this DCF study are supported by various benchmark criteria that I have used to test the reasonableness of the DCF study results.

B. Company Background

Q5. Would you please describe Montana-Dakota's operations and those of its parent company, MDU Resources Group, Inc.?

A. Montana-Dakota is a wholly-owned division of MDU Resources Group, Inc. ("MDU Resources") that is engaged in the generation, transmission and distribution of electricity, and the distribution of natural gas, in the states of North Dakota, Montana, South Dakota, and Wyoming. MDU Resources also owns Cascade Natural Gas Co., which distributes natural gas in the states of Washington and Oregon; Intermountain Gas Company, which distributes gas in the state of Idaho; and it owns Great Plains Natural Gas Company, which distributes natural gas in southeastern North Dakota and western Minnesota. In all, the utility companies within MDU Resources serve 829,000 residential, commercial and industrial natural gas customers in 333 communities and adjacent rural areas across eight states. Through other divisions and subsidiaries, MDU Resources is engaged in utility infrastructure construction, natural gas exploration, production and transmission and also produces and markets aggregates and other construction materials.

In 2009, Montana-Dakota served a total of over 122,000 residential, commercial and industrial electric customers. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's electric assets comprised 9.5 percent of MDU Resources' total assets in 2009 and the electric utility revenues comprised 4.7 percent of the total. In addition, Montana-Dakota's operating income accounted for 7.9 percent of MDU Resources' total, excluding a non-cash write-down of the value of MDU Resources' oil and gas production assets. North Dakota accounted for 58 percent of the electric utility operating revenues, while Wyoming (11 percent), Montana (24 percent) and South Dakota (7 percent) accounted for the other 42 percent of electric utility revenues.

Montana-Dakota' North Dakota operations are primarily served by the company's own generating plants with approximately 463 MW of capacity owned by the interconnected system. Approximately 99 percent of the energy it generated came from coal-fired plants in 2009. When purchased power is included in the mix, approximately 75 percent of Montana-Dakota's electric generating needs came from its own coal-fired plants. In December 2008, Montana-Dakota announced that it intended to develop the Cedar Hills Wind Facility, a 19.5-MW generation project in southwest North Dakota and expand the Diamond Willow Wind Facility in southeast Montana from 19.5 MW to 30 MW. These projects, which are scheduled to achieve commercial operation in mid 2010, will serve to further diversify Montana-Dakota's generation portfolio to meet customer needs.

Q6. Would you please describe Montana-Dakota's service territory?

A. Montana-Dakota North Dakota's electric operations serve central and western North Dakota, with the largest communities being the Bismarck, Dickinson, Mandan and Williston areas. Although its operations tend to be concentrated in cities and towns, a large portion of the local economies are based on agricultural and minerals production. Petroleum is now North Dakota's leading mineral product, just ahead of sand and gravel, lime and salt. North Dakota also has some manufacturing, particularly in food processing and farm equipment. However, Montana-Dakota recently lost a large manufacturing customer – Bobcat, with approximately 27,000 MWh, which closed its Bismarck facility at the end of 2009.

II. FINANCIAL MARKET STUDIES

A. Criteria for a Fair Rate of Return

Q7. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company?

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Electric Company (320 U.S. 591, 603 (1944)).* There the Court described the relevant criteria as follows:

> "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;
2. sufficient to maintain the financial integrity of the regulated company; and,
3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk there is a return that investors must expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q8. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards should apply. When a regulated entity faces competition, consumers will implicitly determine the fair rate of return by their consumption decisions. When regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, the consumer and public interest also lies in establishing a return that will readily attract capital without being excessive.

Q9. How are the costs of preferred stock and long-term debt determined?

A. For purposes of setting regulated rates, the current, embedded costs of preferred stock and long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the fixed dividend and interest obligations that are attached to these sources of capital.

Q10. How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest or dividends is relatively easy to determine. For example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This high degree of uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on several DCF analyses. In addition, I have conducted Risk Premium and Alternative Equity Investment analyses in order to establish benchmarks for a reasonable rate of return. Each of these approaches is described later in this testimony.

B. Interest Rates and the Economy

Q11. What are the general economic factors that affect the cost of capital?

A. Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates and other measures of economic trends influence investors' perceptions of the economic outlook and its implications on both short- and long-term capital markets. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows various general economic statistics. Real growth in the Gross Domestic Product ("GDP") has averaged 2.7 percent annually during the past 30 years, 2.6 percent for the past 20 years and 1.9 percent for the past 10 years. However, real GDP growth increased at an annual rate of 5.6 percent in the fourth quarter of 2009, supporting the projections that the economy will continue to emerge from recession in 2010, with an expected growth in GDP of 2.5 percent. The Federal Reserve has increased its discount rate to 0.75 percent for loans to banks, further signaling that the immediate financial crisis has passed, but unemployment rates remain at unusually high levels. As Page 2 of Schedule 1 of Exhibit No. ___(JSG-2) shows, interest rates on longer-term, intermediate quality corporate bonds have declined since the first half of 2009, and they are now at close to the same level as they were in early 2007.

In addition, credit spreads decreased significantly in the second half of 2009 and have remained relatively stable during the first quarter of 2010. In the last half of 2008, credit spreads rose to unusually high levels, a condition that many market experts attribute to the "flight to safety" in the aftermath of the global economic crisis, which commenced in the 3rd quarter of 2008 with the failure of many borrowers to make payments on sub-prime mortgages that banks were encouraged, and sometimes required, to make under Federal financial regulatory policies. The concept of the "flight to safety" is that risk-averse investors flock to the least risky government-backed securities, lowering the yield on those securities, but significantly increasing the capital costs associated with the more risky corporate debt. The credit spread for A-rated and Baa-rated corporate utility bonds more than doubled in the period from January 2008 to December 2008, while long-term treasury yields were largely declining. By the end of 2009, bond yields returned to early 2008 levels, while credit spreads also have declined.

The net impact is a return to pre-crisis borrowing costs, with recent yields on A-rated public utility bonds at approximately 5.84 percent and the yields on Baa-rated public utility bonds at approximately 6.22 percent.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index has increased at an average annual rate of 2.6 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 2.4 percent. According to Blue Chip, the Consumer Price Index is forecasted to increase by 2.2 percent and 1.9 percent for 2010 and 2011, respectively.[1]

Q12. How are current economic conditions reflected in the equity markets?

A. Although bond yields have returned to pre-crisis levels, the equity markets generally have not fully recovered from the large stock market decline in 2008-2009. This suggests that the cost of common equity generally is higher than it was before the significant risks of equity investment were emphasized during the recent market downturn.

[1] Blue Chip Economic Indicators, *Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, Vol. 35, No. 3 March 10, 2010, at 1.

C. Discounted Cash Flow ("DCF") Method

Q13. Please describe the DCF method of estimating the cost of common equity capital.

A. The DCF method reflects the assumption that the market price of a share of stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method therefore is a matter of calculating the current dividend yield and estimating the long-term future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the DCF method utilizes readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

Q14. What is the appropriate DCF formula to use in this proceeding?

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + .75 g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + .5 g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D_0\,(1 + .625g)}{P} + g \qquad (1)$$

where:

K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D_0 = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

D. Flotation Cost Adjustment

Q15. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital. Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 93 new common stock issues by electric companies from 2000 to 2009. Flotation costs associated with these new issues averaged 3.63 percent.

This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Montana-Dakota must have an expected return that places a value on its equity that is approximately 3.6 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.036.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to <u>enable</u> a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

E. <u>DCF Study of Electric Utility Companies</u>

Q16. Would you please describe the overall approach used in your DCF analysis of Montana-Dakota's cost of common equity?

A. Because Montana-Dakota must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component of the DCF analysis. Since Montana-Dakota is a division of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Montana-Dakota's electric utility operation as a stand-alone company is not possible. As an alternative, I have used a group of electric utilities that have publicly-traded common stock as a proxy group for purposes of estimating the cost of common equity for Montana-Dakota's North Dakota electric utility operations.

Q17. How did you select a group of electric utility proxy companies?

A. I started with a list of 54 electric utility and combination companies covered by Value Line and selected those that owned regulated generation capacity with at least 25 percent of net generation produced from coal-fired facilities, and whose total electric utility assets comprised at least 85 percent of their total consolidated assets. From that group, I eliminated any companies that did not have investment-grade bond ratings with either Standard & Poor's or Moody's (now called Mergent). In addition, I excluded any companies that did not pay dividends or that did not have future growth rate estimates provided by both Value Line and Zack's. When there was no published Zacks growth rate for a potential proxy group company, I substituted a consensus growth estimate from Yahoo! First Call in place of the Zacks growth estimate. As shown on Exhibit No. ___(JSG-2), page 1 of Schedule 2, thirteen electric utility proxy companies met these criteria.

Q18. How did you calculate the dividend yields for the companies in your comparison group?

A. These calculations are shown on page 3 of Schedule 2 of Exhibit No. __(JSG-2). For the price component of the calculation I used the average of the high and low stock prices experienced by each company during the six month period from October 2009 to March 2010. The dividend yields were calculated for each company by using the average indicated annual dividend for the period divided by the average of the stock prices for each company. These dividend yields can be multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the dividend yield component of the DCF model.

Q19. Please describe the method you used in estimating the future growth rate that investors expect from this group of companies?

A. I developed two different DCF analyses of the proxy companies based on two different growth rate estimation methods. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect.

In the first approach I calculated a DCF rate of return using a combination of securities analysts' growth projections and the Value Line retention growth forecasts to produce a Second-Stage Retention Growth analysis. As a second approach, I conducted a Basic DCF analysis that relied solely on the analysts' forecasts for the growth rate component of the model.

F. Second-Stage Retention Growth Analysis

Q20. How did you use your Second-Stage Retention Growth analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A. The Second-Stage Retention Growth rate approach combines: (i) estimates of long-term growth for each company that are published by various investment analysts and (ii) Value Line retention growth forecasts.

Q21. How did you estimate the first stage of expected future growth?

A. Among the best sources of information regarding investors' growth rate expectations are the long-term earnings growth rate forecasts of investment analysts. Zack's is a service that collects estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the Zack's consensus forecasts as the source for analysts' forecasts in my calculations. When Zacks data were missing, I substituted growth rates from Yahoo! First Call. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 5, the average of the analysts' long-term growth rate estimates for the electric utility proxy companies is 5.85 percent.

Q22. Would you please describe the second stage, retention growth rate component of your analysis?

A. In addition to analysts' growth rate forecasts, I have relied upon Value Line projections of the retention growth rates that the proxy companies are expected to begin maintaining three to five years in the future. Although companies may experience extended periods of growth for other reasons, in the long-run, growth in earnings and dividends per share depends in part on the amount of earnings that are being retained and reinvested in a company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and, (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii).

Q23. How can a company's earnings retention rate affect its future growth?

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that are generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (b) times the rate of return on common equity (r) that a company is expected to earn in the future. For example, a company that is expected to earn a return of 15 percent and retain 80 percent of its earnings might be expected to have a growth rate of 12 percent, computed as follows:

$$.80 \times 15\% = 12\%$$

On the other hand, another company that is also expected to earn 15 percent but only retains 20 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$.20 \times 15\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

Q24. How did you calculate the expected future retention rates of the proxy companies?

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected to occur several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 4 of Schedule 2 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that are being retained and reinvested in the company. This earnings retention rate is multiplied times the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 4.31 percent.

Q25. How did you utilize the projected earnings retention rates in estimating expected growth for the proxy companies?

A. As shown on page 5 of Schedule 2 of Exhibit No.___(JSG -2), I calculated a weighted average of the analysts' projected growth rates and the projected retention growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave a two-thirds weighting to the analysts' growth rate projections to reflect the fact that analysts are attempting to evaluate all sources of growth and not just growth that is expected to result from retained earnings. This weighting also reflects the fact that the analysts' long-term growth forecasts can be expected to prevail for a relatively long period of time in the future.

The average of the weighted average growth rates for the proxy companies is 5.34 percent and the median is 5.00 percent.

Q26. How did you utilize these Second-Stage Retention Growth rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A. The dividend yield for each company shown on page 3 of Schedule 2 of Exhibit No.___(JSG-2) is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.036 to arrive at the cost of common equity capital for the proxy companies. These calculations are shown on page 6 of Schedule 2 of Exhibit No.___(JSG-2). This Second-Stage Retention Growth DCF analysis indicates that the cost of common equity capital for the electric utility proxy companies is in a range between 8.8 percent and 12.8 percent. The median for the group is 10.8 percent and the average for the group is 10.9 percent. In addition, the bottom of the fourth quartile of these results is 12.1 percent, which means that one-fourth of the companies had DCF results above 12.1 percent when the Second-Stage Growth rate is used in the analysis.

G. Basic DCF Analysis

Q27. What approach did you use in conducting a Basic DCF analysis?

A. This analysis is conducted in substantially the same manner as the Second-Stage Retention Growth Rate analysis. However, the growth rate component of the analysis is based solely on the analysts' forecasts for each company and the retention growth rate component is omitted from the analysis. This Basic DCF analysis recognizes that the consensus of analysts' forecasts reflects the most important component of investors' growth rate expectations and it assumes that the analysts' forecasts incorporate all information required to estimate a long-term expected growth rate for a company.

Q28. How did you calculate the cost of capital using the Basic DCF analysis?

A. These calculations are shown on page 7 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.036, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a median cost of common equity for the proxy companies of 11.3 percent and an average cost of 11.5 percent. In this analysis, the bottom of the fourth quartile is 13.1 percent, which means that one-fourth of the companies had DCF results greater than 13.1 percent.

H. Risk Premium Analyses

Q29. Have you conducted additional analyses in determining the cost of capital to Montana-Dakota?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual returns on large company common stocks have exceeded the returns on long-term corporate bonds by a premium of 560 basis points (5.6 percent) annually over a long period of time in the past.[2] When this premium is added to the 5.8 percent yield on Moody's corporate bonds that has prevailed in recent months, the result is an investor return requirement for large company stocks of 11.4 percent. However, over the long term companies in Montana-Dakota's size range have had a premium of 1,080 basis points (10.8 percent) over the average returns on long-term corporate bonds. When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 16.6 percent.[3]

I. Alternative Equity Investment Analysis

Q30. Have you analyzed the returns available on common equity investments in other industries?

A. Yes. When investors consider whether to invest their funds in a particular company or line of business, they evaluate the returns potentially available from other companies. This process, whereby projects and companies compete for scarce equity capital, ensures that capital resources are deployed efficiently. As a result, regulated electric utility operations must bid against other companies and other possible projects within the same company for equity capital by offering potential returns that investors find attractive relative to the risks involved.

2 2009 Ibbotson SBBI Valuation Yearbook, pg 23

3 2009 Ibbotson SBBI Valuation Yearbook, pgs 90 and 93.

Q31. What level of returns is potentially available to unregulated companies?

A. The potential returns are often considerably above 20 percent and the average returns for broad-based, diversified portfolios have averaged 20.0 percent or more in recent years. For purposes of comparison with allowed returns for regulated electric operations, a good indicator of earnings on alternative equity investments is provided by data on 566 industrial, retail and transportation companies published by *The Value Line Investment Survey.* Excluding extraordinary and non-recurring items, the average returns on the original cost book value of common equity for these companies in recent years have been:

2004	31.47%
2005	34.64
2006	38.69
2007	39.08
2008	37.25
5-year Average	**36.22%**

Q32. Is it appropriate to set the allowed rate of return for an electric utility company equal to the average return available to industrial companies?

A. The average return for industrials serves as a useful indicator of the cost of capital because electric utility companies must offer potential returns that are competitive with other investments in order to attract capital. It is important to remember that an industrial company has an opportunity to earn returns far in excess of 20 percent. In fact, the average company has earned normal returns on the book value of equity well in excess of 20 percent in recent years. This average reflects many companies that experienced enormous losses as well as those with large returns.

Similarly, when a regulator sets an allowed return it is providing only an *opportunity* to earn that return. During times when its services are most highly valued and it sells greater quantities of service or reduces costs, a regulated company might earn more than this amount, but it might also earn substantially less than the allowed return. Electric utility companies generally have risks that are less than those of the average large industrial company. Consequently, it would be appropriate to view average returns earned by a broad cross-section of industry as being only a general indicator for reasonable allowed returns.

As a benchmark, allowed returns for electric utility companies can be compared to returns on original cost book value for large companies. Normal returns have averaged 36.2 percent during the past five years. As this comparison indicates, an allowed return of 12.0 percent for Montana-Dakota would be quite low in comparison with the returns earned by other large companies.

J. Relative Risk Analysis

Q33. Have you compared the risks faced by Montana-Dakota's North Dakota electric utility operations with the risks faced by the proxy group of companies?

A. Yes. There are four broad categories of risk that concern investors. These include:

i. Business Risk;
ii. Regulatory Risk;
iii. Financial Risk; and,
iv. Market Risk.

Q34. Would you please describe the business risks inherent in the electric industry?

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived electric utility assets, for which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply and competition may change in ways that adversely affect the value of the investment.

The business model of Montana-Dakota and other major utilities is based on the fact that traditionally electricity has been provided most efficiently by large, centralized generating plants connected to the market with extensive networks of transmission and distribution lines. However, in the future, demand for Montana-Dakota's electric services could be affected by the adoption of distributed generation technologies that allow customers to generate their own power instead of relying on utility generation, transmission or distribution. The overall efficiency of these technologies has improved significantly in recent years and some electricity consumers have begun installing and using distributed generation equipment. Shifts in the overall cost of distributed generation relative to the fuel and network costs of centralized utility generation could imperil the ability of some utilities to recover the investments they have made under the traditional "public utility model" of electricity supply.

In addition, the constantly-changing mandates of environmental laws disproportionately impact electric utilities, especially coal-burning utilities. Litigation expenses and exposure to tort claims also is an increasingly important consideration for electric utility investors.

Q35. What are some of the business risks faced by Montana-Dakota's North Dakota electric operations?

A. These operations face many of the same risks that are associated with other electric utilities. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's electric utility operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. For example, Montana-Dakota's electric utility assets are equal to only 6.7 percent of the assets of the median proxy company. Similarly, Montana-Dakota's electric operating revenues and operating income are only 10.0 percent and 10.4 percent of the level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 10 and 15 times the size of Montana-Dakota's electric utility operations.

This smaller size has significant implications for business risks. As noted earlier, Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies. In addition, demographic trends cause Montana-Dakota's North Dakota electric utility operations to be riskier than the operations of the utilities in the proxy group. Though the population in North Dakota has experienced modest increases in recent years, the population in rural areas served by Montana-Dakota's electric utility operations is shrinking as people migrate to more urban areas. As shown on Exhibit No. ___(JSG-2), page 3 of Schedule 1, there has been a 0.48 percent decline in population since 2000 for counties in which Montana-Dakota provides electric service. Because these larger urban areas are also served by rural electric cooperatives, the growth of Montana-Dakota's electric utility operations in these urban areas is significantly limited since these rural electric cooperatives tend to serve the new areas of these cities. Consequently, a long-term problem and source of risk for Montana-Dakota derives from the fact that its investments in facilities to serve its customers are sunk and have a long life. These facilities cannot be easily moved or devoted to another purpose, even if the population declines significantly. The population shifts that are occurring in Montana-Dakota's service territory pose a significant risk that it may at some point be unable to recover the cost of its investments.

In addition, Montana-Dakota's generation portfolio is heavily reliant on coal. Utilities with generation that is heavily weighted toward one fuel source face greater risks that adverse circumstances will arise that render much of their generating capacity uneconomic. Montana-Dakota's customers have benefited greatly from the company's use of low-cost coal, but there is an element of risk associated with this undiversified generating mix. For example, federal legislation that will significantly limit carbon dioxide emissions remains a very real possibility. If restrictions on carbon dioxide were to be enacted, coal-fired generation would be disproportionately impacted. Similarly, as natural gas prices continue to decline, coal-fired generation faces increased risk of becoming uneconomic. In fact, most new generation constructed in recent years has been fueled with natural gas as a result of low gas prices and new, efficient generating technologies.

Q36. What are the regulatory risks faced by Montana-Dakota's North Dakota utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for an electric utility company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow full cost recovery. In effect, the binding constraint on electric utilities is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries.

Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of electric utilities to finance their operations. Thus, in some instances regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the electric utility industry. Regulatory Research Associates ranks the regulatory climate in North Dakota as being "Average". Consequently, the regulatory risk faced by Montana-Dakota in North Dakota generally would be considered to be average also.

Q37. Would you please describe Montana-Dakota's relative financial risks?

A. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from bond ratings. Because Montana-Dakota, as a division of MDU Resources, does not have its own bonds outstanding, it is difficult to make direct comparisons between the ratings of Montana-Dakota and the proxy group. However, page 2 of Schedule 2 of Exhibit No. ___ (JSG-2) shows the bond ratings assigned by Moody's and Standard & Poor's to each of the companies in the comparison group and MDU Resources bonds.

The median bond ratings for companies in the proxy group are BBB for Standard & Poor's and Baa2 for Moody's. In comparison, MDU Resources long term debt carries a BBB+ rating with Standard & Poor's and a Baa1 rating with Moody's. This suggests that the perceived risk of MDU Resources' bonds is reasonably aligned with that of the typical company in the comparison group. The capital structure data shown on Schedule 2, page 8, in Exhibit No. ___ (JSG-2) show that Montana-Dakota's filed common equity ratio, 52.3 percent, is several percentage points greater than the 44.7 percent median for the proxy companies. This common equity ratio, combined with its bond rating, suggests below-average financial risk for Montana-Dakota's North Dakota electric utility operations.

Q38. Would you please describe Montana-Dakota's market risks?

A. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks. Overall, Montana-Dakota's market risk is comparable to that of the companies in the electric utility comparison group.

Q39. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's electric utility operations?

A. Montana-Dakota's North Dakota electric operation faces overall risks that are slightly higher than those of the typical proxy company primarily because Montana-Dakota is smaller and operates in a relatively undiversified local economy. The "average" rating for the regulatory climate in North Dakota is neutral in its effect on investors' perception of the overall risks of Montana-

Dakota's North Dakota electric utility operations relative to the proxy companies. Consequently, Montana-Dakota requires an allowed rate of return that is in the range of the median returns and the 3rd quartile returns, for the companies in the proxy group indicated by my Basic DCF analysis and my Second-Stage Retention Growth DCF analysis.

III. SUMMARY AND CONCLUSIONS

Q40. Would you please summarize the results of your cost of capital study?

A. Yes. I conducted two DCF analyses on a group of electric utility companies that have a range of risks that includes risks roughly comparable to those of Montana-Dakota. These results can be summarized as follows:

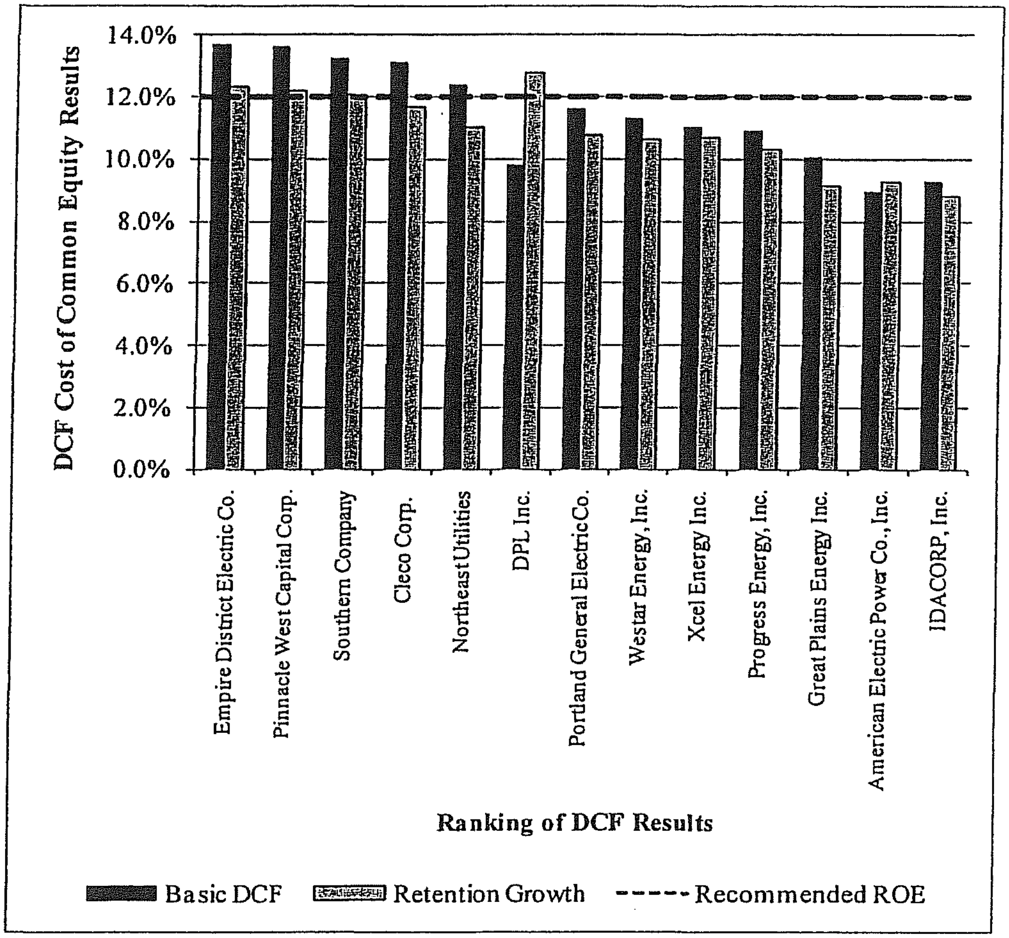
	Results of DCF Analyses	
	2nd Stage Retention Growth	Basic Analysis
High	12.79%	13.68%
3rd Quartile	**12.06%**	**13.13%**
Median: 2nd Quartile	**10.77%**	**11.29%**
1st Quartile	10.33%	10.04%
Low	8.81%	8.94%
Benchmark Analyses		
- Corporate Bonds		
v. Large Companies	11.4%	
v. Small Companies	16.6%	
Alternative Investments		
- Value Line Industrials	36.22%	

My second-stage retention growth analysis indicates a median cost of common equity capital of 10.8 percent and a 3rd Quartile return of 12.1 percent. Because projected retention growth is sustainable indefinitely and it is directly related to the growth rate expectations for an individual company, it is a good indicator of the minimum growth rate that a company can maintain in the very long run. However, companies can achieve growth through means in addition to retained earnings. Consequently, analysts' forecasts provide the best measure of expected growth for the foreseeable future. Combining these two measures provides a good estimate of the long-term growth that investors can reasonably expect from these proxy companies.

The Basic DCF analysis, which relies solely on the analysts' forecasts, also provides a good estimate of investors' growth rate expectations and required return for the proxy companies. This DCF analysis indicates a median required rate of return of 11.3 percent and a 3rd Quartile return of approximately 13.1 percent. Figure 1 shows the results of my DCF analyses of the cost of common equity.

My risk premium analyses indicate that my DCF estimates produce a premium over the corporate bond yield that is below the average long-run risk premium available from common stocks. The DCF return estimates provide a premium over the return on corporate bonds that is considerably below the average premium experienced by companies in Montana-Dakota's relative size range. In addition, my examination of returns available on alternative equity investments suggests that my DCF estimates generally are far below the 36.22 percent average normal returns earned by the Value Line Industrials in recent years.

Figure 1: DCF Results and Cost of Equity for Montana-Dakota



Q41. What rate of return on common equity do you recommend for Montana-Dakota in this proceeding?

A. My analyses indicate that an appropriate rate of return on common equity for Montana-Dakota's North Dakota electric utility operations at this time is 12.0 percent. This recommended return reflects my assessment that Montana-Dakota's overall risks are substantially similar to, but slightly higher than, those of the proxy group.

A return of 12.0 percent is within the range of third quartile values of 10.8 – 12.1 percent and 11.3 – 13.1 percent, for both the Second-Stage Retention Growth Rate analysis and the Basic DCF analysis, respectively. Thus, my recommended return is appropriately positioned to reflect the risks faced by Montana-Dakota's North Dakota electric operations in comparison with the range of risks faced by the proxy companies.

Q42. Does this conclude your Prepared Direct Testimony?

A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1980-2009

Year	Percentage Price Changes: Consumer Price Index	Percentage Price Changes: GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP ($Billions)	Nominal GDP Growth
1980	13.5%	9.1%	-0.3%	2,788.1	8.8%
1981	10.3%	9.4%	2.5%	3,126.8	12.1%
1982	6.2%	6.1%	-1.9%	3,253.2	4.0%
1983	3.2%	4.0%	4.5%	3,534.6	8.6%
1984	4.3%	3.8%	7.2%	3,930.9	11.2%
1985	3.6%	3.0%	4.1%	4,217.5	7.3%
1986	1.9%	2.2%	3.5%	4,460.1	5.8%
1987	3.6%	2.9%	3.2%	4,736.4	6.2%
1988	4.1%	3.4%	4.1%	5,100.4	7.7%
1989	4.8%	3.8%	3.6%	5,482.1	7.5%
1990	5.4%	3.9%	1.9%	5,800.5	5.8%
1991	4.2%	3.5%	-0.2%	5,992.1	3.3%
1992	3.0%	2.4%	3.4%	6,342.3	5.8%
1993	3.0%	2.2%	2.9%	6,667.4	5.1%
1994	2.6%	2.1%	4.1%	7,085.2	6.3%
1995	2.8%	2.1%	2.5%	7,414.7	4.7%
1996	3.0%	1.9%	3.7%	7,838.5	5.7%
1997	2.3%	1.8%	4.5%	8,332.4	6.3%
1998	1.6%	1.1%	4.4%	8,793.5	5.5%
1999	2.2%	1.5%	4.8%	9,353.5	6.4%
2000	3.4%	2.2%	4.1%	9,951.5	6.4%
2001	2.8%	2.3%	1.1%	10,286.2	3.4%
2002	1.6%	1.6%	1.8%	10,642.3	3.5%
2003	2.3%	2.2%	2.5%	11,142.1	4.7%
2004	2.7%	2.8%	3.6%	11,867.8	6.5%
2005	3.4%	3.3%	3.1%	12,638.4	6.5%
2006	3.2%	3.3%	2.7%	13,398.9	6.0%
2007	2.8%	2.9%	2.1%	14,077.6	5.1%
2008	3.8%	2.1%	0.4%	14,441.4	2.6%
2009	-0.4%	1.2%	-2.4%	14,258.7	-1.3%
Average Rate of Change: [1]					
1980-2009	3.7%	3.1%	2.7%	5.8%	5.9%
1990-2009	2.8%	2.3%	2.6%	4.8%	4.9%
2000-2009	2.6%	2.4%	1.9%	4.1%	4.3%

[1] Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

Sources: Department of Labor, Bureau of Labor Statistics, Databases & Tables, website (http://www.bls.gov/data) and Department of Commerce, Bureau of Economic Analysis, National Economic Accounts, website (http://www.bea.gov/national/nipaweb/index.asp)

Montana-Dakota Utilities Co.

Bond Yield Averages
January 2007 - March 2010

		[1]	[2]	[3]	[4]	[5]	[6]
		30-Year	Average	Public Utility Bonds		Credit Spreads	
		T-Bonds	Corporate	A-Rated	Baa-Rated	A-Rated	Baa-Rated
2007	JAN	4.85	5.92	5.96	6.16	1.11	1.31
	FEB	4.82	5.88	5.90	6.10	1.08	1.28
	MAR	4.72	5.84	5.85	6.10	1.13	1.38
	APR	4.86	5.99	5.97	6.24	1.10	1.37
	MAY	4.90	6.00	5.99	6.23	1.08	1.33
	JUN	5.21	6.32	6.30	6.54	1.10	1.34
	JUL	5.10	6.26	6.25	6.49	1.15	1.39
	AUG	4.94	6.26	6.24	6.51	1.30	1.57
	SEP	4.79	6.21	6.18	6.45	1.39	1.66
	OCT	4.78	6.12	6.11	6.36	1.33	1.58
	NOV	4.52	5.97	5.97	6.27	1.45	1.75
	DEC	4.53	6.15	6.16	6.51	1.63	1.98
2008	JAN	4.33	6.02	6.02	6.35	1.68	2.01
	FEB	4.51	6.24	6.21	6.60	1.70	2.08
	MAR	4.38	6.23	6.21	6.68	1.83	2.30
	APR	4.44	6.29	6.29	6.81	1.85	2.37
	MAY	4.60	6.31	6.28	6.79	1.68	2.20
	JUN	4.68	6.43	6.38	6.93	1.70	2.24
	JUL	4.56	6.44	6.40	6.97	1.84	2.41
	AUG	4.50	6.42	6.37	6.98	1.87	2.48
	SEP	4.27	6.50	6.49	7.15	2.22	2.88
	OCT	4.16	7.56	7.56	8.58	3.40	4.42
	NOV	3.98	7.65	7.60	8.98	3.62	5.00
	DEC	2.85	6.71	6.52	8.11	3.68	5.27
2009	JAN	3.10	6.59	6.39	7.90	3.29	4.80
	FEB	3.59	6.64	6.30	7.74	2.71	4.15
	MAR	3.64	6.84	6.42	8.00	2.79	4.36
	APR	3.76	6.85	6.48	8.03	2.73	4.27
	MAY	4.24	6.79	6.49	7.76	2.25	3.52
	JUN	4.51	6.52	6.20	7.30	1.69	2.79
	JUL	4.40	6.17	5.97	6.87	1.56	2.47
	AUG	4.37	5.83	5.71	6.36	1.34	1.99
	SEP	4.19	5.61	5.53	6.12	1.34	1.93
	OCT	4.19	5.63	5.55	6.14	1.36	1.95
	NOV	4.31	5.68	5.63	6.17	1.32	1.86
	DEC	4.50	5.78	5.79	6.26	1.29	1.76
2010	JAN	4.60	5.76	5.77	6.16	1.17	1.55
	FEB	4.62	5.86	5.87	6.25	1.25	1.63
	MAR	4.65	5.81	5.84	6.22	1.20	1.58

Sources:
[1] Bloomberg, U.S. Government Generic 30-Year Treasury Bond
[2] Bloomberg, Moody's Corporate Average Bond Index
[3] Bloomberg, Moody's A-Rated Utility Bond Index
[4] Bloomberg, Moody's Baa-Rated Utility Bond Index
[5] Equals [3] – [1]
[6] Equals [4] – [1]

Montana-Dakota Utilities Co.

POPULATION IN NORTH DAKOTA COUNTIES WHERE MONTANA-DAKOTA PROVIDES ELECTRIC SERVICE 1990 TO 2009

				Population Change	
	1990	2000	2009 Estimate	2000-2009	1990-2009
North Dakota	638,800	642,200	646,844	0.72%	1.26%
Counties Served by Montana-Dakota					
Adams	3,174	2,593	2,236	-13.77%	-29.55%
Bowman	3,596	3,242	3,028	-6.60%	-15.80%
Burke	3,002	2,242	1,839	-17.98%	-38.74%
Burleigh	60,131	69,416	79,822	14.99%	32.75%
Dickey	6,107	5,757	5,217	-9.38%	-14.57%
Divide	2,899	2,283	1,961	-14.10%	-32.36%
Dunn	4,005	3,600	3,365	-6.53%	-15.98%
Emmons	4,830	4,331	3,398	-21.54%	-29.65%
Golden Valley	2,108	1,924	1,621	-15.75%	-23.10%
Grant	3,549	2,841	2,337	-17.74%	-34.15%
Hettinger	3,445	2,715	2,343	-13.70%	-31.99%
Kidder	3,332	2,753	2,201	-20.05%	-33.94%
LaMoure	5,383	4,701	3,908	-16.87%	-27.40%
Logan	2,847	2,308	1,886	-18.28%	-33.75%
Mcintosh	4,021	3,390	2,582	-23.83%	-35.79%
McKenzie	6,383	5,737	5,799	1.08%	-9.15%
Mercer	9,808	8,644	5,799	-32.91%	-40.87%
Morton	23,700	25,303	26,464	4.59%	11.66%
Mountrail	7,021	6,631	6,791	2.41%	-3.28%
Oliver	2,381	2,065	1,643	-20.44%	-31.00%
Renville	3,160	2,610	2,227	-14.67%	-29.53%
Richland	18,148	17,998	16,067	-10.73%	-11.47%
Sioux	3,761	4,044	4,203	3.93%	11.75%
Slope	907	767	649	-15.38%	-28.45%
Stark	22,832	22,636	22,847	0.93%	0.07%
Ward	57,921	58,795	57,012	-3.03%	-1.57%
Williams - includes Williston	21,129	19,761	20,451	3.49%	-3.21%
Total MDU	289,580	289,087	287,696	-0.48%	-0.65%

	1990	2000	2009 Estimate	Population Change 2000-2009	Population Change 1990-2009
Counties Not Served by Montana-Dakota					
Barnes	12,545	11,775	10,753	-8.68%	-14.28%
Benson	7,198	6,964	10,753	54.41%	49.39%
Billings	1,108	888	827	-6.87%	-25.36%
Bottineau	8,011	7,149	6,352	-11.15%	-20.71%
Cass	102,874	123,138	143,339	16.41%	39.33%
Cavalier	6,064	4,831	3,699	-23.43%	-39.00%
Eddy	2,951	2,757	2,288	-17.01%	-22.47%
Foster	3,983	3,759	3,259	-13.30%	-18.18%
Grand Forks	70,683	66,109	66,414	0.46%	-6.04%
Griggs	3,303	2,754	2,346	-14.81%	-28.97%
Hettinger	3,445	2,715	2,343	-13.70%	-31.99%
McHenry	6,528	5,987	5,173	-13.60%	-20.76%
McLean	10,457	9,311	8,310	-10.75%	-20.53%
Nelson	4,410	3,715	3,129	-15.77%	-29.05%
Pembina	9,238	8,585	7,392	-13.90%	-19.98%
Pierce	5,052	4,675	3,990	-14.65%	-21.02%
Ramsey	12,681	12,066	11,240	-6.85%	-11.36%
Ransom	5,921	5,890	5,500	-6.62%	-7.11%
Rolette	12,772	13,674	13,797	0.90%	8.03%
Sargent	4,549	4,366	3,951	-9.51%	-13.15%
Sheridan	2,148	1,710	1,228	-28.19%	-42.83%
Steele	2,420	2,258	1,747	-22.63%	-27.81%
Stutsman	22,241	21,908	20,463	-6.60%	-7.99%
Towner	3,627	2,876	2,209	-23.19%	-39.10%
Traill	8,752	8,477	7,868	-7.18%	-10.10%
Walsh	13,840	12,389	10,798	-12.84%	-21.98%
Wells	5,864	5,102	4,092	-19.80%	-30.22%
Total Other Counties	**352,665**	**355,828**	**363,260**	**2.09%**	**3.00%**

SOURCE: U.S. BUREAU OF THE CENSUS. DECENNIAL CENSUSES OF POPULATION

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Fiscal Year 2009 Operating Data

		Assets ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)	
American Electric Power Co., Inc.	AEP	$48,348	$13,489	$2,771	
Cleco Corp.	CNL	$3,695	$854	$107	
DPL Inc.	DPL	$3,642	$1,589	$428	
Empire District Electric Co.	EDE	$1,840	$497	$74	
Great Plains Energy Inc.	GXP	$8,483	$1,965	$320	
IDACORP, Inc.	IDA	$4,239	$1,050	$204	
Northeast Utilities	NU	$14,058	$5,439	$751	
Pinnacle West Capital Corp.	PNW	$11,808	$3,297	$322	
Portland General Electric Co.	POR	$5,172	$1,804	$208	
Progress Energy, Inc.	PGN	$31,236	$9,885	$1,772	
Southern Company	SO	$52,046	$15,743	$3,268	
Westar Energy, Inc.	WR	$7,525	$1,858	$355	
Xcel Energy Inc.	XEL	$25,488	$9,644	$1,469	
High		$52,046	$15,743	$3,268	
Median		**$8,483**	**$1,965**	**$355**	
Low		$1,840	$497	$74	
Montana-Dakota Electric Utility		**$570**	**$196**	**$37**	
MDU Resources Group, Inc.	MDU	$5,991	$4,177	$467	*
<u>Montana-Dakota Electric Utility % of:</u>					
- Proxy Company Median		**6.7%**	**10.0%**	**10.4%**	
- MDU Resources Group, Inc.		9.5%	4.7%	7.9%	

Sources: 2009 10-Ks

* 2009 Operating Income excluding a $620 million write-down of the value of oil and gas assets.

Montana-Dakota Utilities Co.

Bond Ratings of
Selected Electric Utility Proxy Companies

		Standard & Poor's	Moody's
American Electric Power Co., Inc.	AEP	BBB	--
Cleco Corp.	CNL	BBB	Baa2
DPL Inc.	DPL	A-	A2
Empire District Electric Co.	EDE	BBB-	Baa2
Great Plains Energy Inc.	GXP	BBB	Baa2
IDACORP, Inc.	IDA	BBB	Baa2
Northeast Utilities	NU	BBB	Baa2
Pinnacle West Capital Corp.	PNW	BBB-	Baa3
Portland General Electric Co.	POR	BBB	Baa2
Progress Energy, Inc.	PGN	BBB+	A3
Southern Company	SO	A	--
Westar Energy, Inc.	WR	BBB-	Baa3
Xcel Energy Inc.	XEL	BBB+	Baa1
Median		BBB	Baa2
MDU Resources Group, Inc.		BBB+	Baa1

Source: Bloomberg & SNL

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Dividend Yields
October 2009 – March 2010

		Stock Price October 2009 – March 2010				
		High	Low	Average	Dividend	Yield
American Electric Power Co., Inc.	AEP	$ 34.32	$ 32.39	$ 33.35	$ 1.64	4.92%
Cleco Corp.	CNL	$ 26.73	$ 25.08	$ 25.91	$ 0.90	3.47%
DPL Inc.	DPL	$ 27.73	$ 26.43	$ 27.08	$ 1.16	4.30%
Empire District Electric Co.	EDE	$ 18.81	$ 18.10	$ 18.45	$ 1.28	6.94%
Great Plains Energy Inc.	GXP	$ 18.97	$ 17.54	$ 18.26	$ 0.83	4.55%
IDACORP, Inc.	IDA	$ 32.45	$ 30.22	$ 31.34	$ 1.20	3.83%
Northeast Utilities	NU	$ 25.95	$ 24.32	$ 25.13	$ 0.98	3.88%
Pinnacle West Capital Corp.	PNW	$ 36.86	$ 34.25	$ 35.55	$ 2.10	5.91%
Portland General Electric Co.	POR	$ 20.19	$ 18.79	$ 19.49	$ 1.02	5.23%
Progress Energy, Inc.	PGN	$ 40.11	$ 38.05	$ 39.08	$ 2.48	6.35%
Southern Company	SO	$ 33.22	$ 31.62	$ 32.42	$ 1.75	5.40%
Westar Energy, Inc.	WR	$ 21.77	$ 20.44	$ 21.10	$ 1.21	5.72%
Xcel Energy Inc.	XEL	$ 21.08	$ 19.99	$ 20.53	$ 0.98	4.77%
Average						5.02%

Source: Bloomberg

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Selected Electric Utility Proxy Companies

		Value Line Forecast 2013-2015				
		EPS	DPS	ROE	Retention Rate	Retention Growth
American Electric Power Co., Inc.	AEP	$ 3.50	$ 1.90	10.00%	45.71%	4.57%
Cleco Corp.	CNL	$ 2.50	$ 1.40	11.00%	44.00%	4.84%
DPL Inc.	DPL	$ 2.90	$ 1.50	28.00%	48.28%	13.52%
Empire District Electric Co.	EDE	$ 1.75	$ 1.35	10.00%	22.86%	2.29%
Great Plains Energy Inc.	GXP	$ 1.75	$ 1.20	8.00%	31.43%	2.51%
IDACORP, Inc.	IDA	$ 2.75	$ 1.40	7.50%	49.09%	3.68%
Northeast Utilities	NU	$ 2.25	$ 1.25	9.00%	44.44%	4.00%
Pinnacle West Capital Corp.	PNW	$ 3.25	$ 2.20	9.00%	32.31%	2.91%
Portland General Electric Co.	POR	$ 2.00	$ 1.20	8.50%	40.00%	3.40%
Progress Energy, Inc.	PGN	$ 3.55	$ 2.58	9.00%	27.32%	2.46%
Southern Company	SO	$ 3.00	$ 2.10	13.00%	30.00%	3.90%
Westar Energy, Inc.	WR	$ 2.25	$ 1.40	8.50%	37.78%	3.21%
Xcel Energy Inc.	XEL	$ 2.00	$ 1.10	10.50%	45.00%	4.73%
Average						4.31%

Montana-Dakota Utilities Co.

Second-Stage Retention Growth Rate Estimates for Selected Electric Utility Proxy Companies

		2/3 Zacks 5-Yr Earnings Growth Est.	1/3 Retention Growth	Weighted Average
American Electric Power Co., Inc.	AEP	3.60%	4.57%	3.92%
Cleco Corp.	CNL	9.00%	4.84%	7.61%
DPL Inc.	DPL	5.00%	13.52%	7.84%
Empire District Electric Co. (1)	EDE	6.00%	2.29%	4.76%
Great Plains Energy Inc.	GXP	5.00%	2.51%	4.17%
IDACORP, Inc.	IDA	5.00%	3.68%	4.56%
Northeast Utilities	NU	7.90%	4.00%	6.60%
Pinnacle West Capital Corp.	PNW	7.00%	2.91%	5.64%
Portland General Electric Co.	POR	5.80%	3.40%	5.00%
Progress Energy, Inc.	PGN	4.00%	2.46%	3.49%
Southern Company	SO	7.10%	3.90%	6.03%
Westar Energy, Inc.	WR	5.00%	3.21%	4.40%
Xcel Energy Inc.	XEL	5.70%	4.73%	5.38%
Average		5.85%	4.31%	5.34%
Median		5.70%	3.68%	5.00%

Source: Zacks.com and page 4.

(1) Because there was no published Zacks growth rate for this company, a Yahoo! First Call growth rate was substituted in its place.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth DCF Calculation for Selected Electric Utility Proxy Companies

		Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
American Electric Power Co., Inc.	AEP	4.92%	5.04%	3.92%	8.96%	1.036	9.29%
Cleco Corp.	CNL	3.47%	3.64%	7.61%	11.25%	1.036	11.66%
DPL Inc.	DPL	4.30%	4.51%	7.84%	12.35%	1.036	12.79%
Empire District Electric Co.	EDE	6.94%	7.14%	4.76%	11.90%	1.036	12.34%
Great Plains Energy Inc.	GXP	4.55%	4.66%	4.17%	8.84%	1.036	9.16%
IDACORP, Inc.	IDA	3.83%	3.94%	4.56%	8.50%	1.036	8.81%
Northeast Utilities	NU	3.88%	4.04%	6.60%	10.64%	1.036	11.03%
Pinnacle West Capital Corp.	PNW	5.91%	6.11%	5.64%	11.75%	1.036	12.18%
Portland General Electric Co.	POR	5.23%	5.40%	5.00%	10.40%	1.036	10.77%
Progress Energy, Inc.	PGN	6.35%	6.48%	3.49%	9.97%	1.036	10.33%
Southern Company	SO	5.40%	5.60%	6.03%	11.63%	1.036	12.06%
Westar Energy, Inc.	WR	5.72%	5.88%	4.40%	10.28%	1.036	10.65%
Xcel Energy Inc.	XEL	4.77%	4.93%	5.38%	10.31%	1.036	10.68%
High					12.35%		**12.79%**
		3rd Quartile			11.63%		**12.06%**
Median		**2nd Quartile**			10.40%		**10.77%**
		1st Quartile			9.97%		**10.33%**
Low					8.50%		**8.81%**
Average					10.52%		**10.90%**

Montana-Dakota Utilities Co.

Basic DCF Calculation
for Selected Electric Utility Proxy Companies

		Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
American Electric Power Co., Inc.	AEP	4.92%	5.03%	3.60%	8.63%	1.036	8.94%
Cleco Corp.	CNL	3.47%	3.67%	9.00%	12.67%	1.036	13.13%
DPL Inc.	DPL	4.30%	4.43%	5.00%	9.43%	1.036	9.77%
Empire District Electric Co.	EDE	6.94%	7.20%	6.00%	13.20%	1.036	13.68%
Great Plains Energy Inc.	GXP	4.55%	4.69%	5.00%	9.69%	1.036	10.04%
IDACORP, Inc.	IDA	3.83%	3.95%	5.00%	8.95%	1.036	9.27%
Northeast Utilities	NU	3.88%	4.07%	7.90%	11.97%	1.036	12.41%
Pinnacle West Capital Corp.	PNW	5.91%	6.16%	7.00%	13.16%	1.036	13.64%
Portland General Electric Co.	POR	5.23%	5.42%	5.80%	11.22%	1.036	11.63%
Progress Energy, Inc.	PGN	6.35%	6.51%	4.00%	10.51%	1.036	10.89%
Southern Company	SO	5.40%	5.64%	7.10%	12.74%	1.036	13.20%
Westar Energy, Inc.	WR	5.72%	5.90%	5.00%	10.90%	1.036	11.29%
Xcel Energy Inc.	XEL	4.77%	4.94%	5.70%	10.64%	1.036	11.03%
High					13.20%		**13.68%**
		3rd Quartile			12.67%		**13.13%**
Median		**2nd Quartile**			10.90%		**11.29%**
		1st Quartile			9.69%		**10.04%**
Low					8.63%		**8.94%**
Average					11.05%		**11.46%**

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Capital Structures as of December 31, 2009

		Short-Term Debt (Millions)	%	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
American Electric Power Co., Inc.	AEP	$ 126.0	0.41%	$ 17,498.0	56.77%	$ 61.0	0.20%	$ 13,140.0	42.63%	$ 30,825.0
Cleco Corp.	CNL	$ -	0.00%	$ 1,331.8	54.41%	$ 1.0	0.04%	$ 1,115.0	45.55%	$ 2,447.8
DPL Inc.	DPL	$ -	0.00%	$ 1,324.1	54.11%	$ 22.9	0.94%	$ 1,099.9	44.95%	$ 2,446.9
Empire District Electric Co.	EDE	$ 50.5	3.76%	$ 691.2	51.51%	$ -	0.00%	$ 600.2	44.73%	$ 1,341.8
Great Plains Energy Inc.	GXP	$ 438.6	6.76%	$ 3,214.3	49.56%	$ 39.0	0.60%	$ 2,793.7	43.08%	$ 6,485.6
IDACORP, Inc.	IDA	$ 53.8	1.87%	$ 1,419.1	49.37%	$ -	0.00%	$ 1,401.5	48.76%	$ 2,874.4
Northeast Utilities	NU	$ 100.3	1.14%	$ 5,001.7	56.86%	$ 116.2	1.32%	$ 3,577.9	40.68%	$ 8,796.1
Pinnacle West Capital Corp.	PNW	$ 153.7	2.15%	$ 3,648.2	51.04%	$ -	0.00%	$ 3,345.7	46.81%	$ 7,147.6
Portland General Electric Co.	POR	$ -	0.00%	$ 1,744.0	53.06%	$ -	0.00%	$ 1,543.0	46.94%	$ 3,287.0
Progress Energy, Inc.	PGN	$ 140.0	0.63%	$ 12,678.0	56.68%	$ 93.0	0.42%	$ 9,455.0	42.27%	$ 22,366.0
Southern Company	SO	$ 639.0	1.78%	$ 19,244.0	53.69%	$ 1,082.0	3.02%	$ 14,878.0	41.51%	$ 35,843.0
Westar Energy, Inc.	WR	$ 242.8	4.75%	$ 2,601.4	50.86%	$ 21.4	0.42%	$ 2,248.8	43.97%	$ 5,114.4
Xcel Energy Inc.	XEL	$ 459.0	2.82%	$ 8,432.4	51.80%	$ 105.0	0.64%	$ 7,283.2	44.74%	$ 16,279.7
Median			**1.78%**		**53.06%**		**0.42%**		**44.73%**	

Source: 2009 10-Ks

Montana-Dakota Utilities Co.

Flotation Costs Associated With Electric Company Common Stock Issues 2000 - 2009

Company	Ticker	Year	Month	Day	Number of Shares (000's)	Price to Public	Net Proceeds	Issue Cost as a Percent of Net Proceeds
Consolidated Edison, Inc.	ED	2009	NOV	30	5,000	$42.630	$42.250	0.90%
Ameren Corp.	AEE	2009	SEP	9	19,000	$25.250	$24.469	3.19%
CenterPoint Energy, Inc.	CNP	2009	SEP	9	21,000	$12.000	$11.564	3.77%
UIL Holdings Corp	UIL	2009	MAY	20	4,000	$21.000	$19.869	5.69%
Unitil Corp	UTL	2009	MAY	20	2,400	$20.000	$18.742	6.71%
Great Plains Energy Inc	GXP	2009	MAY	12	10,000	$14.000	$13.460	4.01%
American Electric Power Co Inc	AEP	2009	APR	1	60,000	$24.500	$23.758	3.12%
Northeast Utilities	NU	2009	MAR	16	16,500	$20.200	$19.523	3.47%
Portland General Electric Co	POR	2009	MAR	5	10,850	$14.100	$13.571	3.89%
Progress Energy Inc	PGN	2009	JAN	7	12,500	$37.500	$36.351	3.16%
SCANA Corp	SCG	2008	DEC	31	2,500	$35.500	$34.827	1.93%
Unitil Corp	UTL	2008	DEC	11	2,000	$20.000	$18.950	5.54%
Hawaiian Electric Industries Inc	HE	2008	DEC	3	5,000	$23.000	$22.077	4.18%
Central Vermont Public Service Corp	CV	2008	NOV	18	1,190	$19.000	$17.677	7.48%
Pepco Holdings Inc	POM	2008	NOV	5	14,000	$16.500	$15.867	3.99%
Otter Tail Corp	OTTR	2008	OCT	18	4,500	$30.000	$28.823	4.08%
Xcel Energy Inc	XEL	2008	OCT	9	15,000	$20.200	$20.060	0.70%
Westar Energy Inc	WR	2008	MAY	29	6,000	$24.280	$23.376	3.87%
ITC Holdings Corp	ITC	2008	JAN	17	5,583	$50.150	$47.858	4.79%
Energy East	EAS	2007	MAR	21	9,000	$24.250	$23.504	3.18%
Empire Distric Electric Co.	EDE	2007	DEC	6	3,000	$23.000	$21.920	4.93%
Empire District Electric Co.	EDE	2006	JUN	15	3,200	$20.250	$19.312	4.86%
CLECO Corp.	CNL	2006	AUG	14	6,000	$23.750	$22.860	3.89%
Avista Corp.	AVA	2006	DEC	12	2,750	$25.050	$24.461	2.41%
Cinergy	CIN	2005	JAN	28	3,399	$50.000	$48.279	3.56%
Cinergy	CIN	2005	FEB	11	849	$50.000	$47.617	5.01%
CMS	CMS	2005	MAR	30	20,000	$12.250	$11.809	3.73%
Pinnacle West	PNW	2005	APR	27	5,300	$42.000	$40.588	3.48%
Puget Energy	PSD	2005	NOV	1	15,000	$20.800	$20.650	0.73%
WPS Resources Corp	TEG	2005	NOV	27	1,900	$53.700	$51.955	3.36%
Northeast Utilities	NU	2005	DEC	12	20,000	$19.090	$18.453	3.45%
Hawaiian Electric Industries	HE	2004	MAR	10	2,000	$51.860	$49.711	4.32%
Consolidated Edison, Inc.	ED	2004	APR	11	14,000	$37.750	$36.589	3.17%
Great Plains Energy Corp	GXP	2004	JUN	8	5,000	$30.000	$28.880	3.88%
Great Plains Energy Corp	GXP	2004	JUN	8	6,000	$25.000	$24.167	3.45%
Constellation Energy	CEG	2004	JUN	28	6,000	$37.950	$37.768	0.48%
CMS Energy	CMS	2004	OCT	7	28,500	$9.100	$8.770	3.76%
Ottertail Corporation	OTTR	2004	DEC	7	2,900	$25.450	$24.397	4.32%
IDACORP	IDA	2004	DEC	9	83,500	$30.000	$28.796	4.18%
Ameren Corp.	AEE	2003	JAN	14	5,500	$40.500	$39.107	3.56%
Cinergy	CIN	2003	JAN	31	5,700	$31.100	$30.815	0.93%
American Electric Power Co.	AEP	2003	FEB	27	50,000	$20.950	$20.311	3.15%
PPL Corp	PPL	2003	MAY	15	65,000	$38.250	$37.001	3.38%
Consolidated Edison Inc	ED	2003	MAY	19	87,000	$39.800	$39.451	0.88%
OGE Energy Corp	OGE	2003	AUG	21	4,650	$21.600	$20.810	3.80%
FirstEnergy Corp	FE	2003	SEP	12	28,000	$30.000	$29.010	3.41%
PSEG	PEG	2003	OCT	1	8,250	$41.750	$40.455	3.20%
UNITIL	UTL	2003	OCT	23	6,524	$25.400	$24.130	5.26%

Company	Ticker	Year	Month	Day	Number of Shares (000's)	Price to Public	Net Proceeds	a Percent of Net Proceeds
Puget Energy	PSD	2003	OCT	31	4,550	$22.750	$22.000	3.41%
WPS Resources Corp	TEG	2003	NOV	19	3,500	$43.000	$42.202	1.89%
Empire District Electric Co.	EDE	2003	DEC	11	2,000	$21.150	$20.138	5.03%
TXU Corp	TXU	2002	NOV	25	30,500	$14.770	$14.278	3.45%
Great Plains Energy Inc	GXP	2002	NOV	21	6,000	$22.000	$21.175	3.90%
PSE&G	PEG	2002	NOV	12	15000	$26.550	$25.664	3.45%
Progress Energy, Inc	PGN	2002	NOV	6	14,670	$41.900	$40.857	2.55%
Puget Energy	PSD	2002	NOV	5	5000	$20.700	$19.975	3.63%
Puget Energy	PSD	2002	OCT	31	5,000	$20.700	$19.975	3.63%
TECO Energy, Inc	TE	2002	OCT	10	17,000	$11.000	$10.659	3.20%
Duke Energy	DUK	2002	SEP	25	54,500	$18.350	$17.873	2.67%
PPL Corp	PPL	2002	SEP	12	14,500	$30.500	$29.505	3.37%
Ameren Corp.	AEE	2002	SEP	10	7,000	$42.000	$40.573	3.52%
DQE	DQE	2002	JUN	20	15,000	$13.500	$12.961	4.16%
DTE Energy	DTE	2002	JUN	19	5,500	$43.250	$41.799	3.47%
FPL Group	FPL	2002	JUN	6	5,000	$56.600	$54.850	3.19%
FPL Group (F)	FPL	2002	JUN	6	8,800	$50.000	$48.415	3.27%
American Electric Power Co.	AEP	2002	JUN	5	16,000	$40.900	$39.650	3.15%
TECO Energy, Inc	TE	2002	JUN	4	13,500	$23.000	$22.310	3.09%
TXU Corp	TXU	2002	MAY	31	11,000	$51.150	$49.595	3.14%
Empire District Electric Co.	EDE	2002	MAY	16	2,500	$20.750	$19.868	4.44%
Cleco Corp	CNL	2002	MAY	2	1,750	$33.000	$32.036	3.01%
Xcel Energy Co.	XEL	2002	FEB	28	20,000	$22.500	$21.755	3.42%
FPL Group	FPL	2002	JAN	29	10,000	$50.000	$48.425	3.25%
Empire District Electric	EDE	2001	DEC	4	1,750	$20.370	$19.500	4.46%
Hawaiian Electric Industries	HE	2001	NOV	19	1,500	$37.700	$36.190	4.17%
Alliant Energy Corp	LNT	2001	NOV	15	8,500	$28.000	$26.900	4.09%
Sierra Pacific	NVE	2001	AUG	15	20,500	$15.000	$14.418	4.04%
Progressive Energy	PGN	2001	AUG	14	11,000	$40.000	$38.600	3.63%
WPS Resource Corp	TEG	2001	MAY	2	2,000	$34.360	$33.160	3.62%
Reliant Resources, Inc	RRI	2001	APR	30	52,000	$30.000	$28.500	5.26%
Aquila, Inc		2001	APR	27	12,250	$24.000	$22.620	6.10%
Utilicorp United Inc		2001	APR	27	5,250	$24.000	$22.620	6.10%
Allegheny Energy Inc	AYE	2001	APR	26	12,400	$48.250	$46.800	3.10%
Black Hills Corporation	BKH	2001	APR	18	3,000	$52.000	$49.140	5.82%
Constellation Energy	CEG	2001	MAR	21	12,000	$39.900	$39.280	1.58%
Duke Energy	DUK	2001	MAR	13	25,000	$38.980	$37.947	2.72%
Utilicorp United Inc		2001	MAR	9	10,000	$29.760	$28.940	2.83%
TECO Energy, Inc	TE	2001	MAR	6	7,500	$27.750	$26.883	3.22%
CMS Energy	CMS	2001	FEB	23	10,000	$29.750	$29.560	0.64%
Allete	ALE	2001	JAN	24	6,500	$23.680	$22.679	4.41%
CMS Energy	CMS	2000	OCT	16	11,000	$18.250	$17.770	2.70%
TNPC		2000	OCT	4	24,000	$21.000	$19.790	6.11%
NRG Energy Inc.	NRG	2000	MAY	30	28,170	$15.000	$14.100	6.38%
Southern Company	SO	2000	DEC	7	25,000	$28.500	$27.560	3.41%
AVERAGE								3.63%

Source: Public Utility Finance Tracker through 2007; Bloomberg data from 2008 to present.

MDU Resources Group		2002	NOV	29	2,100	$ 24.000	23.188	3.50%
MDU Resources Group		2002	NOV	19	2,100	$ 24.000	23.280	3.09%

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the North Dakota Public Service Commission

Case No. PU-10-___

Direct Testimony
of
Garret Senger

Q. Would you please state your name, business address and position?

A. Yes. My name is Garret Senger and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Vice President, Controller and Chief Accounting Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. and Great Plains Natural Gas Co., also a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties?

A. As Controller and CAO, I am responsible for providing the direction and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota and Great Plains.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and a Masters in Business Administration. I started my career with Montana-Dakota in 1985 as a financial analyst in the Financial Reporting area and during my tenure with the Company have held positions of increasing responsibility, including Supervisor of Financial Reporting, Manager of Financial Forecasting, Manager of Financial Reporting & Planning, Director of Accounting and Controller.

Q. **Have you testified in other proceedings before regulatory bodies?**

A. Yes, I have testified before the Wyoming Public Service Commission and submitted written testimony in proceedings before the South Dakota Public Utilities Commission and the Montana Public Service Commission.

Q. **Are you familiar with the territory served by Montana-Dakota and the facilities of the Company utilized in providing electric service?**

A. Yes, I am.

Q. **What is the purpose of your testimony in this proceeding?**

A. I am responsible for presenting Statement A, Statement B, and Statement F.

Q. **Were these statements and the data contained therein prepared by you or under your supervision?**

A. Yes, they were.

Q. **Are they true to the best of your knowledge and belief?**

A. Yes, they are.

Q. **Would you describe Statement A and Statement B?**

A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2008 and December 31, 2009, with notes to the balance sheet following. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2009. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. Would you please explain Statement F?

A. Statement F shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2009 and the projected capital structure for 2010. Statement F includes the associated costs of debt, preferred stock and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 9.091%. As explained later, as a result of the Company's efforts to reduce its long term debt costs, this overall rate of return is a reduction from the overall rate of return adopted for use in the Company's most recent electric rate proceeding in 2003, Case No. PU-399-03-296. The basis for the requested 11.50% return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. J. Stephen Gaske but also recognizes the current economic environment. I note that this is the same return on equity adopted for use in Case No. PU-399-03-296.

Page 1 of Statement F summarizes the actual electric utility capital structure at December 31, 2009 and the projected capital structure and the related utility costs of capital for 2010. As shown on page 1, the components of the 2010 projected overall annual rate of return, which are used by Ms. Mulkern to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	2.891%
Short Term Debt	0.079%
Preferred Stock	0.107%
Common Equity	6.014%
Required Rate of Return	9.091%

The debt costs reflected on Statement F, page 1 represent the actual weighted embedded costs of the long-term debt at December 31, 2009 and that projected to be outstanding at December 31, 2010 and is supported by Statement F, Schedule F-1. In calculating the debt costs the "Yield-to-Maturity" method (also referred to as the Internal Rate of Return ("IRR") method) is used to determine the total cost for each respective debt issue as presented on Schedule F-1, page 2 of 5 and page 3 of 5. The yield-to-maturity calculation of each debt issue outstanding gives consideration to the stated rates of interest being paid on such debt, the timing of the interest payments, related issuance expenses, underwriters' commissions, the discount or premium realized upon issuance and the amortization of losses on bond redemption transactions.

Statement F, Schedule F-2, supports the cost of Montana-Dakota's preferred stock capital, representing the weighted cost of the issues at December 31, 2009 and projected to be outstanding at December 31, 2010.

Statement F, Schedule F-3, supports the Company's utility common equity balance at December 31, 2009, and the projected balance as of December 31, 2010.

Q. How does the Company finance its electric utility operations and determine the amount of common equity, debt and preferred stock to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and obligation to provide safe, adequate and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations the Company is making significant capital expenditures for new plant investment, including new renewable resources as mentioned in the testimony of Mr. Goodin. These new investments also have associated operating and maintenance costs. Through its financial planning process the Company determines the amounts of necessary financing required to support these activities. Montana-Dakota finances its operations targeting a 50/50 debt to equity ratio capital structure. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of its short term credit line and the issuance of additional debt and equity financing as required to maintain its targeted capital ratios and finance its combined utility operations. In 2009, the Company obtained $29 million of common equity through new stock issuances between July and October. Also In 2009 the Company issued $50 million of unsecured senior notes in two $25 million private placements with a seven year maturity, at interest rates of 6.66% and 6.61% respectively. In 2008 through a private placement the Company issued $100 million of 10 year unsecured senior notes at an interest rate of 6.04%.

Since 2006 the Company has refinanced essentially all of its long term debt and has lowered its embedded weighted average debt cost from 8.766% at December 31, 2005 to a projected 6.845% at December 31, 2010. The mix of securities employ various maturity dates in order to provide flexibility and mitigate refinancing risks. The Company does not plan to issue additional long term debt prior to December 31, 2010 but anticipates adding $15 million of equity in late 2010, again to achieve and maintain the targeted 50/50 capital structure.

Q. **What does Statement F, Schedule F-1 show?**

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2009 and cost of debt, and it shows the projected long-term debt and associated costs for 2010. Page 2 shows the cost and the debt balance by issue at December 31, 2009, and page 3 shows the projected cost and the debt balance by issue at December 31, 2010.

Q. **How did you derive the projected cost of debt as for 2010?**

A. The projected cost of debt for 2010 is based upon the yield to maturity of each debt issue outstanding.

Q. **Would you please describe Statement F, Schedule F-1, page 4 and explain the amortization method utilized?**

A. Page 4 reflects the detail by issue of the annual amortization of net discounts (losses) and unamortized issuance expenses on the redemption of long term debt. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues, the same calculation as is used by the Company for accounting purposes.

Q. **Would you please describe Statement F, Schedule F-1, page 5?**

A. Page 5 presents the projected average short term debt balance for 2010 as well as the average cost of short term debt. A twelve month average of short term debt is used in the cost of capital calculation to reflect the seasonality in the short term debt balance. Short term debt is historically at or near its peak in December and the twelve month average calculation is more reflective of the borrowing level than a year end balance.

Q. **What does Statement F, Schedule F-2 show?**

A. Page 1 presents the preferred stock balances at December 31, 2009 and the projected balances for December 31, 2010. The anticipated weighted cost of preferred stock is also shown. Page 2 sets forth the various preferred stock issues outstanding at December 31, 2009 and page 3 sets forth the projected issues outstanding at December 31, 2010.

Q. **What does Statement F, Schedule F-3 show?**

A. Page 1 presents the common equity balance at December 31, 2009 and the projected balance for 2010 reflecting the projected activity in the balance.

Q. **Why did the Company defer the costs related to the study of future**

generation for Lignite Vision 21 (LV21) and Milton R Young III when these projects did not continue and not charge them to expense in the year the projects ceased?

A. As discussed by Ms. Stomberg, both LV21 and Milton R. Young III were potential regional base load power sources Montana-Dakota evaluated to provide power to its customers. The plant development costs for future generation were a necessary cost associated with the development of Montana-Dakota's next generating facility and should be recovered from customers. The total costs incurred to date including AFUDC include $2.1 million for Lignite Vision 21 and $332,000 for Milton R. Young III. These costs were incurred to study the development of future generation. While both of projects did not move forward these costs were deferred and included with the BS II costs into a construction work order designated as future generation costs. All these costs were viewed by the Company as prudently incurred costs necessary to provide future generation. Many events unfolded outside of the Company's control that drew these projects to a close as stated in Ms. Stomberg's testimony. Upon the determination not to proceed with Big Stone II these costs were subsequently transferred to a regulatory asset and a filing was made in Montana, North Dakota and South Dakota requesting an accounting order to defer these costs until the next general rate case. Accounting orders were approved in Montana and South Dakota.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Response No. PSC-044
Attachment A
Wyoming Docket No. 20004-81-ER-09

Exhibit No.___(JSG-1)

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

DOCKET NO. 20004-___-ER-09

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1717 Rhode Island Avenue, Suite 630, Washington, DC 20036.

Q2. Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. Subsequently, I spent a year assisting in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988 I returned to H. Zinder & Associates ("HZA") and was President of the company from 2000 to 2008. In May 2008, HZA merged with Concentric Energy Advisors ("CEA") and I became a Senior Vice President of CEA.

Q3. Have you presented expert testimony in other proceedings?

A. Yes. I have testified or filed testimony or affidavits before the Federal Energy Regulatory Commission on more than thirty occasions. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements and market power. I also have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil and gas pipeline operations before seven state regulatory bodies, including the Wyoming Public Service Commission, and before the Alberta Utilities Commission and the Comisión Reguladora de Energia de México ("CRE"). In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing and generating plant economics before the U.S. Postal Rate Commission, the Alberta Energy and Utilities Board, the Ontario Energy Board, the New Brunswick Energy and Utilities Board and five state public utility Commissions. During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses. Finally, I am a member of the American Economic Association, the Financial Management Association, and the American Finance Association.

I. INTRODUCTION

A. Scope and Overview

Q4. What is the scope of your testimony in this proceeding?

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to evaluate the required overall rate of return for the company's electric utility operations in the state of Wyoming and to estimate the cost of common equity capital for those operations. In this testimony, I calculate the cost of common equity capital for Montana-Dakota's electric utility operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Montana-Dakota's Wyoming electric utility operations. The results of this DCF study are supported by various benchmark criteria that I have used to test the reasonableness of the DCF study results.

Q5. What rate of return is Montana-Dakota requesting in this proceeding?

A. Based on its test period capital structure, Montana-Dakota is requesting the following rate of return:

Source	Amount (000s)	Percent	Cost	Overall Rate of Return
Long-Term Debt	$280,505.1	44.959%	6.793%	3.054%
Short-Term Debt	$17,287.4	2.771%	3.773%	0.105%
Preferred Stock	$15,600.0	2.500%	4.594%	0.115%
Common Equity	$310,520.0	49.770%	12.750%	6.346%
TOTAL	$623,912.5	100.00%		9.620%

As my testimony discusses, an overall allowed rate of return of 9.620 percent, with a 12.75 percent return on common equity, represents the cost of capital for Montana-Dakota.

B. <u>Company Background</u>

Q6. Would you please describe Montana-Dakota's operations and those of its parent company, MDU Resources Group, Inc.?

A. Montana-Dakota is a wholly-owned division of MDU Resources Group, Inc. ("MDU Resources") that is engaged in the generation, transmission and distribution of electricity, and the distribution of natural gas, in the states of North Dakota, Montana, South Dakota and Wyoming. MDU Resources also owns Cascade Natural Gas Co., which distributes natural gas in the states of Washington and Oregon; Intermountain Gas Company, which distributes gas in the state of Idaho; and it owns Great Plains Natural Gas Company, which distributes natural gas in southeastern North Dakota and western Minnesota. In all, MDU Resources serves 822,000 residential, commercial and industrial natural gas customers in 333 communities and adjacent rural areas across eight states. Through other divisions and subsidiaries, MDU Resources is engaged in utility infrastructure construction, natural gas exploration, production and transmission and also produces and markets aggregates and other construction materials.

In 2008 Montana-Dakota served a total of over 121,000 residential, commercial and industrial electric customers. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's electric assets comprised 7.3 percent of MDU Resources' total assets. In addition, the electric utility revenues and operating income accounted for 4.2 percent and 6.9 percent of MDU Resources' total, respectively. Wyoming accounted for 10 percent of the electric utility operating revenues, while North Dakota (60 percent), Montana (23 percent) and South Dakota (7 percent) accounted for the other 90 percent of electric utility revenues.

Historically, Montana-Dakota has purchased all of the generation resources for its Wyoming electric operations. However, Montana-Dakota was given an option to participate in the construction of the Wygen III plant as part of a contract renewal in a power purchase agreement with Black Hills Power Inc. On April 9, 2009, Montana-Dakota, exercised that option and purchased a 25% ownership interest in the 100 MW, Wygen III, coal-fired generation facility under construction near Gillette, Wyoming. Montana-Dakota will own 25MW of the plant, which is scheduled to be completed and online in June 2010. It is estimated that the construction of the plant will add $62 million to Montana-Dakota's existing rate base of $19.5 million in Wyoming.

Q7. Would you please describe Montana-Dakota's service territory?

A. Montana-Dakota Wyoming's electric operations primarily serve Sheridan County and the surrounding area. Sheridan, a western tourist destination, has a population of approximately 27,000 and is bordered on the west by the Big Horn Mountains and Bighorn National Forest and to the east by the Wyoming high plains. Sheridan's economy is relatively undiversified, largely dependent on its coal mining and coal-bed methane extraction industries, as well as its burgeoning retirement community and tourism industry. Economic growth has been spurred by the new home construction, updated infrastructure and expanded services to accommodate Sheridan's growing population.

II. FINANCIAL MARKET STUDIES

A. Criteria for a Fair Rate of Return

Q8. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company?

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Electric Company (320 U.S. 591, 603 (1944)).* There the Court described the relevant criteria as follows:

> "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;
2. sufficient to maintain the financial integrity of the regulated company; and,
3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk there is a return that investors must expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q9. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards should apply. When a regulated entity faces competition, consumers will implicitly determine the fair rate of return by their consumption decisions. When regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, the consumer and public interest also lies in establishing a return that will readily attract capital without being excessive.

Q10. How are the costs of preferred stock and long-term debt determined?

A. For purposes of setting regulated rates, the current, embedded costs of preferred stock and long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the fixed dividend and interest obligations that are attached to these sources of capital.

Q11. How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest or dividends is relatively easy to determine. For example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This high degree of uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on several DCF analyses. In addition, I have conducted Risk Premium and Alternative Equity Investment analyses in order to establish benchmarks for a reasonable rate of return. Each of these approaches is described later in this testimony.

B. Cost of Debt

Q12. What debt cost rates have you used for Montana-Dakota?

A. Calculation of the overall cost of debt and the effective cost of each of the debt issues is shown in the Prepared Direct Testimony of Garret Senger, Controller for Montana-Dakota.

Q13. What cost of preferred stock did you use?

A. Montana-Dakota's annual cost of preferred stock is 4.594 percent, as shown also in the Prepared Direct Testimony of Garret Senger.

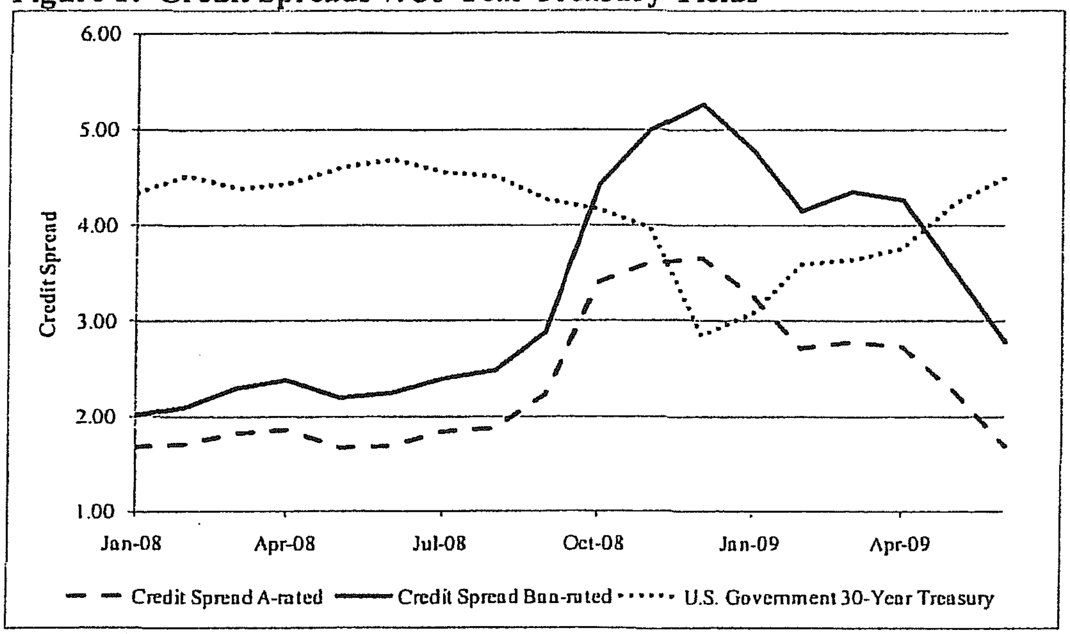
C. Interest Rates and the Economy

Q14. What are the general economic factors that affect the cost of capital?

Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates and other measures of economic trends influence investors' perceptions of the economic outlook and its implications on both short- and long-term capital markets. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows various general economic statistics. Real growth in the Gross Domestic Product ("GDP") has averaged 3.0 percent annually during the past 30 years, 2.8 percent for the past 20 years and 2.7 percent for the past ten years. However, real GDP growth plunged in the last quarter of 2008 and the first quarter of 2009, by 6.3 and 6.1 percent, respectively; resulting in year over year growth estimated at only 1.9 percent for 2009. Recent information suggests that the pace of economic contraction is slowing, and though economic activity is expected to remain weak for some time, it is expected that the economy will begin to emerge from recession at the latter half of this year. The Federal Reserve has targeted a Federal Funds rate of 0 to ¼ percent for loans to banks and continues to anticipate that economic conditions will warrant these exceptionally low rates for an extended period. As Page 2 of Schedule 1 of Exhibit No. ___(JSG-2) shows, despite the Fed's effort to provide liquidity to credit markets by reducing the Fed Funds Rate to essentially zero, interest rates on longer-term, intermediate quality corporate bonds have not declined but rather have increased since the first half of 2008 . This is often an indicator of expectations of greater inflation.

In addition, credit spreads remain at unusually high levels, a condition that many market experts attribute to the "flight to safety" in the aftermath of the global economic crisis, which commenced in the 3rd quarter of 2008 with the failure of many borrowers to make payments on sub-prime mortgages that banks were encouraged, and sometimes required, to make under Federal financial regulatory policies. The concept of the "flight to safety" is that risk-weary investors flock to the least risky government-backed securities, lowering the yield on those securities, but significantly increasing the capital costs associated with the more risky corporate debt. In the chart below, one can see that the credit spread for A-rated and Baa-rated corporate utility bonds more than doubled in the period from January 2008 to December 2008, while long-term treasury yields were largely declining. Credit spreads and bond yields appear to be returning to early 2008 levels in mid-2009.

Figure 1: Credit Spreads v. 30-Year Treasury Yields



Source: Bloomberg

The net impact is higher corporate borrowing costs despite lower treasury yields. The recent yields on A-rated public utility bonds have been approximately 6.23 percent and the yields on Baa-rated public utility bonds have been approximately 7.35 percent.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index has increased at an average annual rate of 2.7 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 2.3 percent. However, inflation has decelerated in recent months and, according to Blue Chip, the Consumer Price Index is forecast to contract by

0.8% in 2009, resulting in year over year increases in CPI of 1.7 percent and 1.9 percent for 2009 and 2010, respectively.[1]

Q15. How will lower economic growth and higher inflation be reflected in the equity markets?

A. The stock market is a discounting mechanism, which means that investors attempt to set current stock prices based on their expectations for corporate profits, economic growth, inflation, and interest rates. Stock investors are cognizant of slower economic growth because this places downward pressure on corporate profitability. The price of equities reflects investor expectations about the future stream of corporate earnings, discounted at a specified rate to compensate for the risk associated with variability in those earnings. When earnings deteriorate and investors become less certain about the reliability of that future earnings stream, the price of equities would be expected to decline because investors would demand a higher expected rate of return to compensate them for this additional risk. Overall, these measures suggest that utility costs of capital are rising despite the slowing U.S. economy and the decline in U.S. treasury yields. Stagnant economic growth and rising corporate debt rates have correspondingly increased Montana-Dakota's equity return requirement.

[1] Blue Chip Economic Indicators, *Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, Vol. 34, No. 5 May 10, 2009, at 1.

D. Discounted Cash Flow ("DCF") Method

Q16. Please describe the DCF method of estimating the cost of common equity capital.

A. The DCF method reflects the assumption that the market price of a share of stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method therefore is a matter of calculating the current dividend yield and estimating the long-term future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the DCF method utilizes readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

Q17. What is the appropriate DCF formula to use in this proceeding?

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + .75 g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + .5 g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D\,(1 + .625g)}{P} + g \qquad (1)$$

where:

K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

E. Flotation Cost Adjustment

Q18. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital. Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 81 new common stock issues by electric companies from 2000 to 2009. Flotation costs associated with these new issues averaged 3.67 percent. This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Montana-Dakota must have an expected return that places a value on its equity that is approximately 3.7 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.037.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to <u>enable</u> a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

F. DCF Study of Electric Utility Companies

Q19. Would you please describe the overall approach used in your DCF analysis of Montana-Dakota's cost of common equity?

A. Because Montana-Dakota must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component of the DCF analysis. Since Montana-Dakota is a division of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Montana-Dakota's electric utility operation as a stand-alone company is not possible. As an alternative, I have used a group of electric utilities that have publicly-traded common stock as a proxy group for purposes of estimating the cost of common equity for Montana-Dakota's Wyoming electric utility operations.

Q20. How did you select a group of electric utility proxy companies?

A. I started with the a list of 54 electric utility and combination companies covered by Value Line and selected those that owned regulated generation capacity with at least 25 percent of net generation produced from coal-fired facilities, and whose total electric utility assets comprised at least 85 percent of their total consolidated assets. From that group, I eliminated any companies that did not have investment-grade bond ratings with either Standard & Poor's or Moody's (now called Mergent). In addition, I excluded any companies that did not pay dividends or that did not have future growth rate estimates provided by both Value Line and Zack's. When there was no published Zacks growth rate for a potential proxy group company, I substituted a consensus growth estimate from Yahoo! First Call in place of the Zacks growth estimate. As shown on Exhibit No. ___(JSG-2), page 1 of Schedule 2, thirteen electric utility proxy companies met these criteria.

Q21. How did you calculate the dividend yields for the companies in your comparison group?

A. These calculations are shown on page 3 of Schedule 2 of Exhibit No. __(JSG-2). For the price component of the calculation I used the average of the high and low stock prices experienced by each company during the six month period from January 2009 to June 2009. The dividend yields were calculated for each company by using the average indicated annual dividend for the period divided by the average of the stock prices for each company. These dividend yields can be multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the dividend yield component of the DCF model.

Q22. Please describe the method you used in estimating the future growth rate that investors expect from this group of companies?

A. I developed two different DCF analyses of the proxy companies based on two different growth rate estimation methods. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect.

In the first approach I calculated a DCF rate of return using a combination of securities analysts' growth projections and the Value Line retention growth forecasts to produce a Second-Stage Retention Growth analysis. As a second approach, I conducted a Basic DCF analysis that relied solely on the analysts' forecasts for the growth rate component of the model.

G. <u>Second-Stage Retention Growth Analysis</u>

Q23. How did you use your Second-Stage Retention Growth analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A. The Second-Stage Retention Growth rate approach combines: (i) estimates of long-term growth for each company that are published by various investment analysts and (ii) Value Line retention growth forecasts.

Q24. How did you estimate the first stage of expected future growth?

A. Among the best sources of information regarding investors' growth rate expectations are the long-term earnings growth rate forecasts of investment analysts. Zack's is a service that collects estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the Zack's consensus forecasts as the source for analysts' forecasts in my calculations. When Zacks data were missing, I substituted growth rates from Yahoo! First Call. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 5, the average of the analysts' long-term growth rate estimates for the electric utility proxy companies is 6.4 percent.

Q25. Would you please describe the second stage, retention growth rate component of your analysis?

A. In addition to analysts' growth rate forecasts, I have relied upon Value Line projections of the retention growth rates that the proxy companies are expected to begin maintaining three to five years in the future. Although companies may experience extended periods of growth for other reasons, in the long-run, growth in earnings and dividends per share depends in part on the amount of earnings that are being retained and reinvested in a company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and, (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii).

Q26. How can a company's earnings retention rate affect its future growth?

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that are generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (b) times the rate of return on common equity (r) that a company is expected to earn in the future. For example, a company that is expected to earn a return of 15 percent and retain 80 percent of its earnings might be expected to have a growth rate of 12 percent, computed as follows:

$$.80 \times 15\% = 12\%$$

On the other hand, another company that is also expected to earn 15 percent but only retains 20 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$.20 \times 15\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

Q27. How did you calculate the expected future retention rates of the proxy companies?

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected to occur several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 4 of Schedule 2 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that are being retained and reinvested in the company. This earnings retention rate is multiplied times the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 4.2 percent.

Q28. How did you utilize the projected earnings retention rates in estimating expected growth for the proxy companies?

A. As shown on page 5 of Schedule 2 of Exhibit No.___(JSG -2), I calculated a weighted average of the analysts' projected growth rates and the projected retention growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave a two-thirds weighting to the analysts' growth rate projections to reflect the fact that analysts are attempting to evaluate all sources of growth and not just growth that is expected to result from retained earnings. This weighting also reflects the fact that the analysts' long-term growth forecasts can be expected to prevail for a relatively long period of time in the future.

The average of the weighted average growth rates for the proxy companies is 5.7 percent and the median is 4.9 percent.

Q29. How did you utilize these Second-Stage Retention Growth rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A. The dividend yield for each company shown on page 3 of Schedule 2 of Exhibit No.___(JSG-2) is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.037 to arrive at the cost of common equity capital for the proxy companies. These calculations are shown on page 6 of Schedule 2 of Exhibit No.___(JSG-2). This Second-Stage Retention Growth DCF analysis indicates that the cost of common equity capital for the electric utility proxy companies is in a range between 10.0 percent and 16.1 percent. The median for the group is 11.6 percent and the average for the group is 12.1 percent. In addition, the bottom of the fourth quartile of these results is 12.6 percent, which means that one-fourth of the companies had DCF results above 12.6 percent when the Second-Stage Growth rate is used in the analysis.

H. Basic DCF Analysis

Q30. What approach did you use in conducting a Basic DCF analysis?

A. This analysis is conducted in substantially the same manner as the Second-Stage Retention Growth Rate analysis. However, the growth rate component of the analysis is based solely on the analysts' forecasts for each company and the retention growth rate component is omitted from the analysis. This Basic DCF analysis recognizes that the consensus of analysts' forecasts reflects the most important component of investors' growth rate expectations and it assumes that the analysts' forecasts incorporate all information required to estimate a long-term expected growth rate for a company.

Q31. How did you calculate the cost of capital using the Basic DCF analysis?

A. These calculations are shown on page 7 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.037, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a median cost of common equity for the proxy companies of 12.7 percent and an average cost of 12.9 percent. In this analysis, the bottom of the fourth quartile is 13.0 percent, which means that one-fourth of the companies had DCF results greater than 13.0 percent.

I. Risk Premium Analyses

Q32. Have you conducted additional analyses in determining the cost of capital to Montana-Dakota?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual returns on large company common stocks have exceeded the returns on long-term corporate bonds by a premium of 550 basis points (5.5 percent) annually over a long period of time in the past. When this premium is added to the 6.8 percent yield on Moody's corporate bonds that has prevailed in recent months, the result is an investor return requirement for large company stocks of 12.3 percent. However, over the long term companies in Montana-Dakota's size range have had a premium of 1,523 basis points (15.23 percent) over the average returns on long-term corporate bonds. When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 22.0 percent.

J. <u>Alternative Equity Investment Analysis</u>

Q33. Have you analyzed the returns available on common equity investments in other industries?

A. Yes. When investors consider whether to invest their funds in a particular company or line of business, they evaluate the returns potentially available from other companies. This process, whereby projects and companies compete for scarce equity capital, ensures that capital resources are deployed efficiently. As a result, regulated electric utility operations must bid against other companies and other possible projects within the same company for equity capital by offering potential returns that investors find attractive relative to the risks involved.

Q34. What level of returns is potentially available to unregulated companies?

A. The potential returns are often considerably above 20 percent and the average returns for broad-based, diversified portfolios have averaged 20.0 percent or more in recent years. For purposes of comparison with allowed returns for regulated electric operations, a good indicator of earnings on alternative equity investments is provided by data on 573 industrial, retail and transportation companies published by *The Value Line Investment Survey.* Excluding extraordinary and non-recurring items, the average returns on the original cost book value of common equity for these companies in recent years have been:

2003	27.79%
2004	31.40
2005	33.94
2006	38.60
2007	39.71
5-year Average	**34.29%**

Q35. Is it appropriate to set the allowed rate of return for an electric utility company equal to the average return available to industrial companies?

A. The average return for industrials serves as a useful indicator of the cost of capital because electric utility companies must offer potential returns that are competitive with other investments in order to attract capital. It is important to remember that an industrial company has an opportunity to earn returns far in excess of 20 percent. In fact, the average company has earned normal returns on the book value of equity well in excess of 20 percent in recent years. This average reflects many companies that experienced enormous losses as well as those with large returns.

Similarly, when a regulator sets an allowed return it is providing only an *opportunity* to earn that return. During times when its services are most highly valued and it sells greater quantities of service or reduces costs, a regulated company might earn slightly more than this amount, but it might earn substantially less than the allowed return and, in fact, often does earn less than that amount. Electric utility companies generally have risks that are less than those of the average large industrial company. Consequently, it would be appropriate to view average returns earned by a broad cross-section of industry as being only a general indicator for reasonable allowed returns.

As a benchmark, allowed returns for electric utility companies can be compared to returns on book value for large companies. Normal returns have averaged 34.3 percent during the past five years. As this comparison indicates, an allowed return of 12.75 percent for Montana-Dakota would be quite low in comparison with the returns earned by other large companies.

K. Relative Risk Analysis

Q36. Have you compared the risks faced by Montana-Dakota's Wyoming electric utility operations with the risks faced by the proxy group of companies?

A. Yes. There are four broad categories of risk that concern investors. These include:

i. Business Risk;
ii. Regulatory Risk;
iii. Financial Risk; and,
iv. Market Risk.

Q37. Would you please describe the business risks inherent in the electric industry?

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived electric utility assets, for which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply and competition may change in ways that adversely affect the value of the investment.

The business model of Montana-Dakota and other major utilities is based on the fact that traditionally electricity has been provided most efficiently by large, centralized generating plants connected to the market with extensive networks of transmission and distribution lines. However, in the future, demand for Montana-Dakota's electric services could be affected by the adoption of distributed generation technologies that allow customers to generate their own power instead of relying on utility generation, transmission or distribution. The overall efficiency of these technologies has improved significantly in recent years and some electricity consumers have begun installing and using distributed generation equipment. Shifts in the overall cost of distributed generation relative to the fuel and network costs of centralized utility generation could imperil the ability of some utilities to recover the investments they have made under the traditional "public utility model" of electricity supply.

In addition, the constantly-changing mandates of environmental laws disproportionately impact electric utilities, especially coal-burning utilities. Litigation expenses and exposure to tort claims also is an increasingly important consideration for electric utility investors.

Q38. What are some of the business risks faced by Montana-Dakota's Wyoming electric operations?

A. These operations face many of the same risks that are associated with other electric utilities. However, Montana-Dakota's relative risks have increased as a result of its investment in the construction of the Wygen III coal-fired generation facility. In contrast with a power purchase contract, ownership of generating capacity requires Montana-Dakota to invest funds and place additional capital at risk.

For example, Montana-Dakota will significantly increaseits rate base by investing in the construction of the Wygen III coal-fired generation facility. An investment of this magnitude increases the operating risk of the utility by putting more investment dollars at risk for non-recovery. Additionally, rate recovery will not occur for the substantial capital investment until the project comes into operation in second quarter 2010.

In addition, Montana-Dakota faces several risks that distinguish it from many other utilities. A substantial investment in coal-fired generation in today's uncertain legislative environment carries an additional risk where evolving carbon legislation could significantly impact the economics of the investment. The acquisition of the Wygen III coal facility exposes the utility to a variety of incremental operating risks which are magnified after consideration of the small size of the utility.

As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's electric utility operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. For example, Montana-Dakota's electric utility assets are equal to only 6.1 percent of the assets of the median proxy company. Similarly, Montana-Dakota's electric operating revenues and operating income are only 11.3 percent and 8.1 percent of the level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 9 and 16 times the size of Montana-Dakota's electric utility operations.

This smaller size has significant implications for business risks. As noted earlier, Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies. On a practical level, Montana-Dakota's relatively small electric utility operations are heavily dependent upon a relatively undiversified local economy. Though Sheridan Wyoming has experienced steady population growth which has supported its services, retail, infrastructure and housing industries, it is somewhat dependent on the coal and coal-bed methane extraction industries to support employment in the area. Though these industries are not considered particularly risky, they could be affected by upcoming carbon legislation or market shifts that affect the value of their resources. Factors that negatively influence the local economy can reduce demand for Montana-Dakota's electric services and adversely impact investments in facilities used to provide those services. Considering only its smaller size, Montana-Dakota might require a return that is more than 100 basis points higher than the return required for the typical proxy company.

Q39. What are the regulatory risks faced by Montana-Dakota's Wyoming utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for an electric utility company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow full cost recovery. In effect, the binding constraint on electric utilities is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries.

Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of electric utilities to finance their operations. Thus, in some instances regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the electric utility industry. Regulatory Research Associates ranks the regulatory climate in Wyoming as being "Average". Consequently, the regulatory risk faced by Montana-Dakota in Wyoming generally would be considered to be average also.

Q40. Would you please describe Montana-Dakota's relative financial risks?

A. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from bond ratings. Because Montana-Dakota does not have its own bonds outstanding, it is difficult to make direct comparisons between the ratings of Montana-Dakota and the proxy group. However, page 2 of Schedule 2 of Exhibit No. ___ (JSG-2) shows the bond ratings assigned by Moody's and Standard & Poor's to each of the companies in the comparison group and MDU Resources bonds that are secured by the assets of the Montana-Dakota division of MDU Resources. The median bond ratings for companies in the proxy group are BBB for Standard & Poor's and Baa2 for Moody's. In comparison, MDU Resources bonds carry a BBB+ rating with Standard & Poor's and a Baa1 rating with Moody's. This suggests that the perceived risk of MDU Resources' bonds is reasonably aligned with that of the typical company in the comparison group. The capital structure data shown on Schedule 2, page 8, in Exhibit No. ___ (JSG-2) show that Montana-Dakota's filed common equity ratio, 49.8 percent, is several percentage points greater than the 44.0 percent median for the proxy companies. This common equity ratio, combined with its bond rating, suggests below-average financial risk for Montana-Dakota's Wyoming electric utility operations.

Q41. Would you please describe Montana-Dakota's market risks?

A. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks. Because of the risks associated with constructing a new coal plant and the magnitude of the Wygen III facility relative to Montana-Dakota Wyoming's small size, Montana-Dakota's degree of market risk is slightly above that of the companies in the electric utility comparison group.

Q42. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's electric utility operations?

A. Montana-Dakota's Wyoming Electric operation faces overall risks that are slightly more risky than those of the proxy companies. Although it has financial risks that are below average relative to the proxy companies, Montana-Dakota has business risks that are significantly above average. In particular, it is exceptionally small relative to the proxy companies, and it is exposed to significant risk in the construction of the Wygen III coal unit. Further, Montana-Dakota operates in a relatively undiversified local economy. The "average" rating for the regulatory climate in Wyoming is neutral in its effect on investors' perception of the overall risks of Montana-Dakota's Wyoming electric utility operations relative to the proxy companies. Consequently, Montana-Dakota requires an allowed rate of return that is somewhat above the median returns and approximately equal to the 3rd quartile returns, for the companies in the proxy group indicated by my Basic DCF analysis and my Second-Stage Retention Growth DCF analysis.

III. SUMMARY AND CONCLUSIONS

Q43. Would you please summarize the results of your cost of capital study?

A. Yes. I conducted two DCF analyses on a group of electric utility companies that have a range of risks that includes risks roughly comparable to those of Montana-Dakota. These results can be summarized as follows:

	Results of DCF Analyses	
	2nd Stage Retention Growth	Basic Analysis
High	16.08%	19.75%
3rd Quartile	**12.62%**	**12.95%**
Median: 2nd Quartile	**11.56%**	**12.73%**
1st Quartile	11.09%	11.13%
Low	10.03%	10.30%

Benchmark Analyses

- Corporate Bonds	
v. Large Companies	12.30%
v. Small Companies	22.00%

Alternative Investments

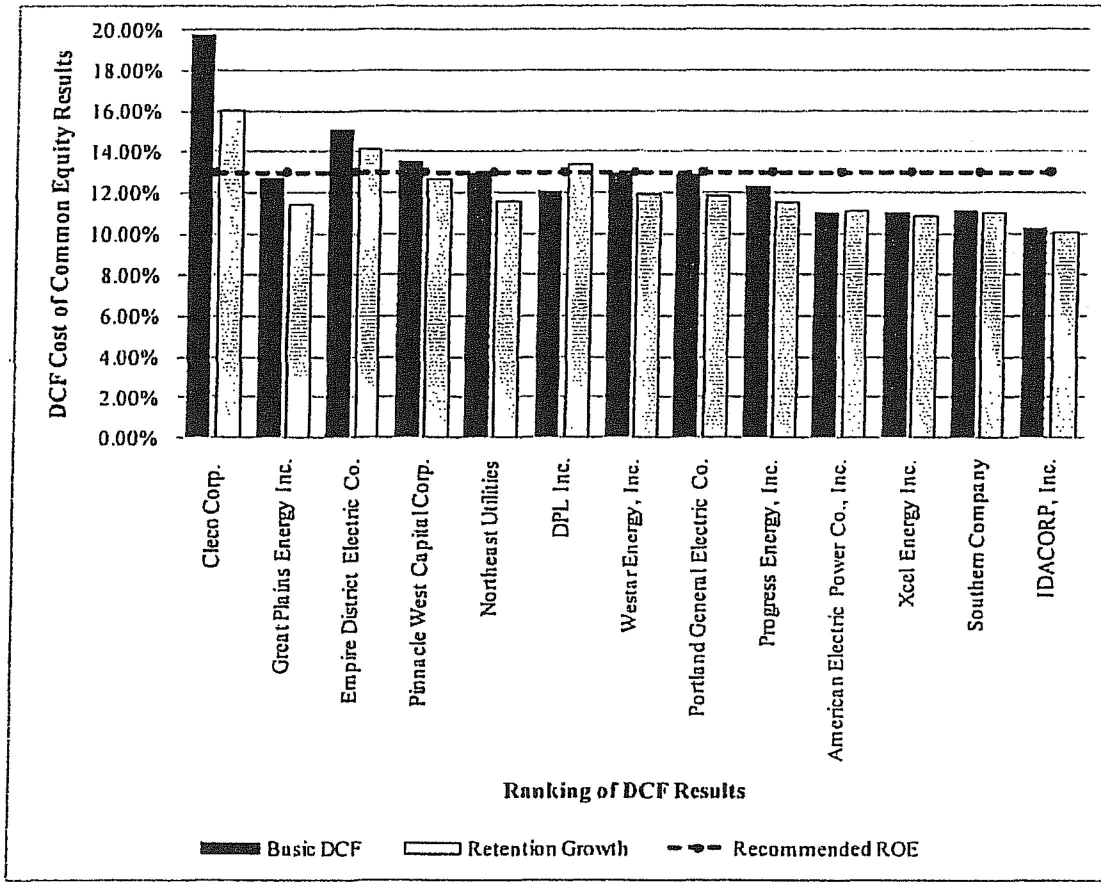
- Value Line Industrials	34.29%

My second-stage retention growth analysis indicates a median cost of common equity capital of 11.6 percent and a 3rd Quartile return of 12.6 percent. Because projected retention growth is sustainable indefinitely and it is directly related to the growth rate expectations for an individual company, it is a good indicator of the minimum growth rate that a company can maintain in the very long run. However, companies can achieve growth through means in addition to retained earnings. Consequently, analysts' forecasts provide the best measure of expected growth for the foreseeable future. Combining these two measures provides a good estimate of the long-term growth that investors can reasonably expect from these proxy companies.

The Basic DCF analysis, which relies solely on the analysts' forecasts, also provides a good estimate of investors' growth rate expectations and required return for the proxy companies. This DCF analysis indicates a median required rate of return of 12.7 percent and a 3rd Quartile return of approximately 13.0 percent. Chart 2 shows the results of my DCF analyses of the cost of common equity.

My risk premium analyses indicate that my DCF estimates produce a premium over the corporate bond yield that is below the average long-run risk premium available from common stocks. The DCF return estimates provide a premium over the return on corporate bonds that is considerably below the average premium experienced by companies in Montana-Dakota's relative size range. In addition, my examination of returns available on alternative equity investments suggests that my DCF estimates generally are far below the 34.3 percent average normal returns earned by the Value Line Industrials in recent years.

Figure 2: DCF Results and Cost of Equity for Montana-Dakota



Q44. What rate of return on common equity do you recommend for Montana-Dakota in this proceeding?

A. My analyses indicate that an appropriate rate of return on common equity for Montana-Dakota's Wyoming electric utility operations at this time is **12.75 percent**. This recommended return reflects my assessment that Montana-Dakota's overall risks are above average relative to the proxy group. A return of 12.75 percent is approximately equal to the third quartile values of 12.6 percent and 13.0 percent, for the Second-Stage Retention Growth Rate analysis and the Basic DCF analysis, respectively and it is nearly identical to the median return of 12.73 percent produced by the Basic DCF analysis. Thus, my recommended return is appropriately positioned to reflect the risks faced by Montana-Dakota's Wyoming electric operations in comparison with the range of risks faced by the proxy companies.

Q45. Does this conclude your Prepared Direct Testimony?

A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1978-2008

	Percentage Price Changes				
Year	Consumer Price Index	GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP ($Billions)	Nominal GDP Growth
1978	7.6%	7.0%	5.6%	2,294.7	13.0%
1979	11.3%	8.3%	3.2%	2,563.3	11.7%
1980	13.5%	9.1%	-0.2%	2,789.5	8.8%
1981	10.3%	9.4%	2.5%	3,128.4	12.1%
1982	6.2%	6.1%	-1.9%	3,255.0	4.0%
1983	3.2%	4.0%	4.5%	3,536.7	8.7%
1984	4.3%	3.8%	7.2%	3,933.2	11.2%
1985	3.6%	3.0%	4.1%	4,220.3	7.3%
1986	1.9%	2.2%	3.5%	4,462.8	5.7%
1987	3.6%	2.7%	3.4%	4,739.5	6.2%
1988	4.1%	3.4%	4.1%	5,103.8	7.7%
1989	4.8%	3.8%	3.5%	5,484.4	7.5%
1990	5.4%	3.9%	1.9%	5,803.1	5.8%
1991	4.2%	3.5%	-0.2%	5,995.9	3.3%
1992	3.0%	2.3%	3.3%	6,337.7	5.7%
1993	3.0%	2.3%	2.7%	6,657.4	5.0%
1994	2.6%	2.1%	4.0%	7,072.2	6.2%
1995	2.8%	2.0%	2.5%	7,397.7	4.6%
1996	3.0%	1.9%	3.7%	7,816.9	5.7%
1997	2.3%	1.7%	4.5%	8,304.3	6.2%
1998	1.6%	1.1%	4.2%	8,747.0	5.3%
1999	2.2%	1.4%	4.5%	9,268.4	6.0%
2000	3.4%	2.2%	3.7%	9,817.0	5.9%
2001	2.8%	2.4%	0.8%	10,128.0	3.2%
2002	1.6%	1.7%	1.6%	10,469.6	3.4%
2003	2.3%	2.1%	2.5%	10,960.8	4.7%
2004	2.7%	2.9%	3.6%	11,685.9	6.6%
2005	3.4%	3.3%	2.9%	12,421.9	6.3%
2006	3.2%	3.2%	2.8%	13,178.4	6.1%
2007	2.8%	2.7%	2.0%	13,807.5	4.8%
2008	3.8%	2.2%	1.1%	14,264.6	3.3%
Average Rate of Change: 1/					
1978-2008	4.2%	3.5%	3.0%	6.3%	6.5%
1988-2008	3.1%	2.5%	2.8%	5.3%	5.4%
1998-2008	2.7%	2.3%	2.7%	5.0%	5.0%

1/ Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

Sources: Department of Labor, Bureau of Labor Statistics, Databases & Tables, website (http://www.bls.gov/data) and Department of Commerce, Bureau of Economic Analysis, National Economic Accounts, website (http://www.bea.gov/national/nipaweb/index.asp)

Montana-Dakota Utilities Co.

Bond Yield Averages
June 2006 - June 2009

		[1]	[2]	[3]	[4]	[5]	[6]
		30-Year	Average	Public Utility Bonds		Credit Spreads	
		T-Bonds	Corporate	A-Rated	Baa-Rated	A-Rated	Baa-Rated
2006	JUN	5.15	6.36	6.40	6.61	1.25	1.46
	JUL	5.14	6.33	6.37	6.61	1.23	1.47
	AUG	4.99	6.16	6.20	6.43	1.20	1.43
	SEP	4.85	5.98	6.00	6.26	1.15	1.41
	OCT	4.85	5.97	5.98	6.24	1.13	1.39
	NOV	4.68	5.78	5.80	6.04	1.12	1.36
	DEC	4.68	5.79	5.81	6.05	1.13	1.37
2007	JAN	4.85	5.92	5.96	6.16	1.11	1.31
	FEB	4.82	5.88	5.90	6.10	1.08	1.28
	MAR	4.72	5.84	5.85	6.10	1.13	1.38
	APR	4.86	5.99	5.97	6.24	1.10	1.37
	MAY	4.90	6.00	5.99	6.23	1.08	1.33
	JUN	5.21	6.32	6.30	6.54	1.10	1.34
	JUL	5.10	6.26	6.25	6.49	1.15	1.39
	AUG	4.94	6.26	6.24	6.51	1.30	1.57
	SEP	4.79	6.21	6.18	6.45	1.39	1.66
	OCT	4.78	6.12	6.11	6.36	1.33	1.58
	NOV	4.52	5.97	5.97	6.27	1.45	1.75
	DEC	4.53	6.15	6.16	6.51	1.63	1.98
2008	JAN	4.33	6.02	6.02	6.35	1.68	2.01
	FEB	4.51	6.24	6.21	6.60	1.70	2.08
	MAR	4.38	6.23	6.21	6.68	1.83	2.30
	APR	4.44	6.29	6.29	6.81	1.85	2.37
	MAY	4.60	6.31	6.28	6.79	1.68	2.20
	JUN	4.68	6.43	6.38	6.93	1.70	2.24
	JUL	4.56	6.44	6.40	6.97	1.84	2.41
	AUG	4.50	6.42	6.37	6.98	1.87	2.48
	SEP	4.27	6.50	6.49	7.15	2.22	2.88
	OCT	4.16	7.56	7.56	8.58	3.40	4.42
	NOV	3.98	7.65	7.60	8.98	3.62	5.00
	DEC	2.85	6.71	6.52	8.11	3.68	5.27
2009	JAN	3.10	6.59	6.39	7.90	3.29	4.80
	FEB	3.59	6.64	6.30	7.74	2.71	4.15
	MAR	3.64	6.84	6.42	8.00	2.79	4.36
	APR	3.76	6.85	6.48	8.03	2.73	4.27
	MAY	4.24	6.79	6.49	7.76	2.25	3.52
	JUN	4.53	6.57	6.23	7.35	1.70	2.82

Sources:
[1] Bloomberg, U.S. Government Generic 30-Year Treasury Bond
[2] Bloomberg, Moody's Corporate Average Bond Index
[3] Bloomberg, Moody's A-Rated Utility Bond Index
[4] Bloomberg, Moody's Baa-Rated Utility Bond Index
[5] Equals [3] - [1]
[6] Equals [4] - [1]

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Fiscal Year 2008 Operating Data

		Assets ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)
American Electric Power Co., Inc.	AEP	$45,155	$14,440	$2,787
Cleco Corp.	CNL	$3,341	$1,080	$115
DPL Inc.	DPL	$3,675	$1,602	$436
Empire District Electric Co.	EDE	$1,714	$518	$71
Great Plains Energy Inc.	GXP	$7,869	$1,670	$275
IDACORP, Inc.	IDA	$4,023	$960	$191
Northeast Utilities	NU	$13,988	$5,800	$591
Pinnacle West Capital Corp.	PNW	$11,620	$3,367	$477
Portland General Electric Co.	POR	$5,023	$1,745	$217
Progress Energy, Inc.	PGN	$29,873	$9,167	$1,683
Southern Company	SO	$48,347	$17,127	$3,506
Westar Energy, Inc.	WR	$7,443	$1,839	$285
Xcel Energy Inc.	XEL	$24,958	$11,203	$1,391
High		$48,347	$17,127	$3,506
Median		**$7,869**	**$1,839**	**$436**
Low		$1,714	$518	$71
Montana-Dakota Electric Utility		**$480**	**$208**	**$35**
MDU Resources Group, Inc.	MDU	$6,588	$5,003	$512
<u>Montana-Dakota Electric Utility % of:</u>				
- Proxy Company Median		**6.1%**	**11.3%**	**8.1%**
- MDU Resources Group, Inc.		7.3%	4.2%	6.9%

Sources: 2008 10-Ks

Montana-Dakota Utilities Co.

Bond Ratings of
Selected Electric Utility Proxy Companies

		Standard & Poor's	Moody's
American Electric Power Co., Inc.	AEP	BBB	--
Cleco Corp.	CNL	BBB	Baa1
DPL Inc.	DPL	A-	A3
Empire District Electric Co.	EDE	BBB-	Baa2
Great Plains Energy Inc.	GXP	BBB	Baa1
IDACORP, Inc.	IDA	BBB	Baa2
Northeast Utilities	NU	BBB	Baa2
Pinnacle West Capital Corp.	PNW	BBB-	Baa3
Portland General Electric Co.	POR	BBB+	Baa2
Progress Energy, Inc.	PGN	BBB+	A3
Southern Company	SO	A	--
Westar Energy, Inc.	WR	BBB-	Baa3
Xcel Energy Inc.	XEL	BBB+	Baa1
Median		BBB	Baa2
MDU Resources Group, Inc.		BBB+	Baa1

Source: SNL Financial

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Dividend Yields
January 2009 – June 2009

		Stock Price January 2009 – June 2009				
		High	Low	Average	Dividend	Yield
American Electric Power Co., Inc.	AEP	$ 29.90	$ 26.70	$ 28.30	$ 1.64	5.80%
Cleco Corp.	CNL	$ 22.74	$ 20.39	$ 21.57	$ 0.90	4.17%
DPL Inc.	DPL	$ 23.01	$ 21.00	$ 22.00	$ 1.13	5.15%
Empire District Electric Co.	EDE	$ 16.55	$ 14.60	$ 15.57	$ 1.28	8.22%
Great Plains Energy Inc.	GXP	$ 16.66	$ 14.30	$ 15.48	$ 0.97	6.26%
IDACORP, Inc.	IDA	$ 26.26	$ 23.86	$ 25.06	$ 1.20	4.79%
Northeast Utilities	NU	$ 22.94	$ 20.91	$ 21.92	$ 0.93	4.26%
Pinnacle West Capital Corp.	PNW	$ 30.44	$ 26.93	$ 28.68	$ 2.10	7.32%
Portland General Electric Co.	POR	$ 19.07	$ 16.87	$ 17.97	$ 0.99	5.49%
Progress Energy, Inc.	PGN	$ 37.85	$ 34.58	$ 36.21	$ 2.48	6.85%
Southern Company	SO	$ 32.57	$ 29.14	$ 30.86	$ 1.72	5.56%
Westar Energy, Inc.	WR	$ 19.12	$ 17.05	$ 18.08	$ 1.19	6.56%
Xcel Energy Inc.	XEL	$ 18.71	$ 17.32	$ 18.02	$ 0.96	5.30%
Average						5.82%

Source: Bloomberg

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Selected Electric Utility Proxy Companies

		Value Line Forecast 2012-2014				
		EPS	DPS	ROE	Retention Rate	Retention Growth
American Electric Power Co., Inc.	AEP	$ 3.50	$ 1.90	10.50%	45.71%	4.80%
Cleco Corp.	CNL	$ 2.50	$ 1.60	11.50%	36.00%	4.14%
DPL Inc.	DPL	$ 2.65	$ 1.30	19.50%	50.94%	9.93%
Empire District Electric Co.	EDE	$ 2.00	$ 1.40	11.00%	30.00%	3.30%
Great Plains Energy Inc.	GXP	$ 1.50	$ 1.00	6.50%	33.33%	2.17%
IDACORP, Inc.	IDA	$ 2.75	$ 1.20	7.50%	56.36%	4.23%
Northeast Utilities	NU	$ 2.25	$ 1.15	8.50%	48.89%	4.16%
Pinnacle West Capital Corp.	PNW	$ 3.25	$ 2.20	9.00%	32.31%	2.91%
Portland General Electric Co.	POR	$ 2.25	$ 1.30	9.00%	42.22%	3.80%
Progress Energy, Inc.	PGN	$ 3.60	$ 2.56	9.50%	28.89%	2.74%
Southern Company	SO	$ 3.00	$ 2.00	14.00%	33.33%	4.67%
Westar Energy, Inc.	WR	$ 2.15	$ 1.40	8.00%	34.88%	2.79%
Xcel Energy Inc.	XEL	$ 2.00	$ 1.10	10.50%	45.00%	4.73%
Average						4.18%

Source: *Value Line*, March 27, 2009, May 8, 2009, and May 29, 2009.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth Rate Estimates for Selected Electric Utility Proxy Companies

		2/3 Zacks 5-Yr Earnings Growth Est.	1/3 Retention Growth	Weighted Average
American Electric Power Co., Inc.	AEP	4.70%	4.80%	4.73%
Cleco Corp.	CNL	14.50%	4.14%	11.05%
DPL Inc.	DPL	6.30%	9.93%	7.51%
Empire District Electric Co. (1)	EDE	6.00%	3.30%	5.10%
Great Plains Energy Inc.	GXP	5.80%	2.17%	4.59%
IDACORP, Inc.	IDA	5.00%	4.23%	4.74%
Northeast Utilities	NU	8.00%	4.16%	6.72%
Pinnacle West Capital Corp.	PNW	5.50%	2.91%	4.64%
Portland General Electric Co.	POR	6.70%	3.80%	5.73%
Progress Energy, Inc.	PGN	4.80%	2.74%	4.11%
Southern Company	SO	5.00%	4.67%	4.89%
Westar Energy, Inc.	WR	5.70%	2.79%	4.73%
Xcel Energy Inc.	XEL	5.20%	4.73%	5.04%
Average		6.40%	4.18%	5.66%
Median		5.70%	4.14%	4.89%

Source: Zacks.com and page 4.

(1) Because there was no published Zacks growth rate for this company, a Yahoo! First Call growth rate was substituted in its place.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth DCF Calculation for Selected Electric Utility Proxy Companies

		Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
American Electric Power Co., Inc.	AEP	5.80%	5.97%	4.73%	10.70%	1.037	11.09%
Cleco Corp.	CNL	4.17%	4.46%	11.05%	15.51%	1.037	16.08%
DPL Inc.	DPL	5.15%	5.39%	7.51%	12.90%	1.037	13.38%
Empire District Electric Co.	EDE	8.22%	8.48%	5.10%	13.58%	1.037	14.08%
Great Plains Energy Inc.	GXP	6.26%	6.43%	4.59%	11.02%	1.037	11.43%
IDACORP, Inc.	IDA	4.79%	4.93%	4.74%	9.67%	1.037	10.03%
Northeast Utilities	NU	4.26%	4.44%	6.72%	11.15%	1.037	11.56%
Pinnacle West Capital Corp.	PNW	7.32%	7.53%	4.64%	12.17%	1.037	12.62%
Portland General Electric Co.	POR	5.49%	5.69%	5.73%	11.42%	1.037	11.84%
Progress Energy, Inc.	PGN	6.85%	7.02%	4.11%	11.14%	1.037	11.55%
Southern Company	SO	5.56%	5.73%	4.89%	10.62%	1.037	11.01%
Westar Energy, Inc.	WR	6.56%	6.76%	4.73%	11.49%	1.037	11.91%
Xcel Energy Inc.	XEL	5.30%	5.47%	5.04%	10.51%	1.037	10.89%
High					15.51%		**16.08%**
		3rd Quartile			12.17%		**12.62%**
Median		**2nd Quartile**			11.15%		**11.56%**
		1st Quartile			10.70%		**11.09%**
Low					9.67%		**10.03%**
Average					11.68%		**12.11%**

Montana-Dakota Utilities Co.

Basic DCF Calculation
for Selected Electric Utility Proxy Companies

		Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
American Electric Power Co., Inc.	AEP	5.80%	5.97%	4.70%	10.67%	1.037	11.06%
Cleco Corp.	CNL	4.17%	4.55%	14.50%	19.05%	1.037	19.75%
DPL Inc.	DPL	5.15%	5.35%	6.30%	11.65%	1.037	12.08%
Empire District Electric Co.	EDE	8.22%	8.53%	6.00%	14.53%	1.037	15.06%
Great Plains Energy Inc.	GXP	6.26%	6.48%	5.80%	12.28%	1.037	12.73%
IDACORP, Inc.	IDA	4.79%	4.94%	5.00%	9.94%	1.037	10.30%
Northeast Utilities	NU	4.26%	4.47%	8.00%	12.47%	1.037	12.93%
Pinnacle West Capital Corp.	PNW	7.32%	7.57%	5.50%	13.07%	1.037	13.55%
Portland General Electric Co.	POR	5.49%	5.72%	6.70%	12.42%	1.037	12.88%
Progress Energy, Inc.	PGN	6.85%	7.05%	4.80%	11.85%	1.037	12.29%
Southern Company	SO	5.56%	5.73%	5.00%	10.73%	1.037	11.13%
Westar Energy, Inc.	WR	6.56%	6.80%	5.70%	12.50%	1.037	12.95%
Xcel Energy Inc.	XEL	5.30%	5.47%	5.20%	10.67%	1.037	11.06%
High					19.05%		**19.75%**
		3rd Quartile			12.50%		**12.95%**
Median		**2nd Quartile**			12.28%		**12.73%**
		1st Quartile			10.73%		**11.13%**
Low					9.94%		**10.30%**
Average					12.45%		**12.91%**

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Capital Structures as of December 31, 2008

		Short-Term Debt (Millions)	%	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
American Electric Power Co., Inc.	AEP	$ 1,976.0	6.80%	$ 16,308.0	56.16%	$ 61.0	0.21%	$ 10,693.0	36.82%	$ 29,038.0
Cleco Corp.	CNL	$ -	0.00%	$ 1,170.4	52.45%	$ 1.0	0.05%	$ 1,059.8	47.50%	$ 2,231.2
DPL Inc.	DPL	$ -	0.00%	$ 1,551.8	60.85%	$ 22.9	0.90%	$ 975.6	38.25%	$ 2,550.3
Empire District Electric Co.	EDE	$ 102.0	8.08%	$ 631.7	50.03%	$ -	0.00%	$ 528.9	41.89%	$ 1,262.6
Great Plains Energy Inc.	GXP	$ 584.2	10.07%	$ 2,627.3	45.29%	$ 39.0	0.67%	$ 2,550.6	43.97%	$ 5,801.1
IDACORP, Inc.	IDA	$ 151.3	5.55%	$ 1,269.7	46.62%	$ -	0.00%	$ 1,302.4	47.82%	$ 2,723.4
Northeast Utilities	NU	$ 618.9	7.19%	$ 4,857.4	56.40%	$ 116.2	1.35%	$ 3,020.3	35.07%	$ 8,612.8
Pinnacle West Capital Corp.	PNW	$ 670.5	9.15%	$ 3,209.2	43.81%	$ -	0.00%	$ 3,446.0	47.04%	$ 7,325.7
Portland General Electric Co.	POR	$ 203.0	7.09%	$ 1,306.0	45.62%	$ -	0.00%	$ 1,354.0	47.29%	$ 2,863.0
Progress Energy, Inc.	PGN	$ 1,050.0	5.07%	$ 10,890.0	52.54%	$ 93.0	0.45%	$ 8,693.0	41.94%	$ 20,726.0
Southern Company	SO	$ 953.0	2.91%	$ 17,433.0	53.24%	$ 1,082.0	3.30%	$ 13,276.0	40.54%	$ 32,744.0
Westar Energy, Inc.	WR	$ 174.9	3.61%	$ 2,456.8	50.73%	$ 21.4	0.44%	$ 2,189.6	45.21%	$ 4,842.7
Xcel Energy Inc.	XEL	$ 455.3	2.88%	$ 8,290.5	52.42%	$ 105.0	0.66%	$ 6,963.7	44.03%	$ 15,814.4
Median			**5.55%**		**52.42%**		**0.44%**		**43.97%**	

Source: 2008 10-Ks

Montana-Dakota Utilities Co.

Flotation Costs Associated With Electric Company Common Stock Issues 2000 - 2009

Company	Ticker	Year	Month	Day	Number of Shares (000's)	Price to Public	Net Proceeds	Issue Cost as a Percent of Net Proceeds
UIL Holdings Corp	UIL	2009	MAY	20	4,000	$21.000	19.869	5.69%
Unitil Corp	UTL	2009	MAY	20	2,400	$20.000	18.742	6.71%
Great Plains Energy Inc	GXP	2009	MAY	12	10,000	$14.000	13.460	4.01%
American Electric Power Co Inc	AEP	2009	APR	1	60,000	$24.500	23.758	3.12%
Northeast Utilities	NU	2009	MAR	16	16,500	$20.200	19.523	3.47%
Portland General Electric Co	POR	2009	MAR	5	10,850	$14.100	13.571	3.89%
Progress Energy Inc	PGN	2009	JAN	7	12,500	$37.500	36.351	3.16%
SCANA Corp	SCG	2008	DEC	31	2,500	$35.500	34.827	1.93%
Unitil Corp	UTL	2008	DEC	11	2,000	$20.000	18.950	5.54%
Hawaiian Electric Industries Inc	HE	2008	DEC	3	5,000	$23.000	22.077	4.18%
Central Vermont Public Service Corp	CV	2008	NOV	18	1,190	$19.000	17.677	7.48%
Pepco Holdings Inc	POM	2008	NOV	5	14,000	$16.500	15.867	3.99%
Otter Tail Corp	OTTR	2008	OCT	18	4,500	$30.000	28.823	4.08%
Xcel Energy Inc	XEL	2008	OCT	9	15,000	$20.200	20.060	0.70%
Westar Energy Inc	WR	2008	MAY	29	6,000	$24.280	23.376	3.87%
ITC Holdings Corp	ITC	2008	JAN	17	5,583	$50.150	47.858	4.79%
Energy East	EAS	2007	MAR	21	9,000	$24.250	23.504	3.18%
Empire Distric Electric Co.	EDE	2007	DEC	6	3,000	$23.000	21.920	4.93%
Empire District Electric Co.	EDE	2006	JUN	15	3,200	$20.250	19.312	4.86%
CLECO Corp.	CNL	2006	AUG	14	6,000	$23.750	22.860	3.89%
Avista Corp.	AVA	2006	DEC	12	2,750	$25.050	24.461	2.41%
Cinergy	CIN	2005	JAN	28	3,399	$50.000	48.279	3.56%
Cinergy	CIN	2005	FEB	11	849	$50.000	47.617	5.01%
CMS	CMS	2005	MAR	30	20,000	$12.250	11.809	3.73%
Pinnacle West	PNW	2005	APR	27	5,300	$42.000	40.588	3.48%
Puget Energy	PSD	2005	NOV	1	15,000	$20.800	20.650	0.73%
WPS Resources Corp	TEG	2005	NOV	27	1,900	$53.700	51.955	3.36%
Northeast Utilities	NU	2005	DEC	12	20,000	$19.090	18.453	3.45%
Hawaiian Electric Industries	HE	2004	MAR	10	2,000	$51.860	49.711	4.32%
Con Edison, Inc.	ED	2004	APR	11	14,000	$37.750	36.589	3.17%
Great Plains Energy Corp	GXP	2004	JUN	8	5,000	$30.000	28.880	3.88%
Great Plains Energy Corp	GXP	2004	JUN	8	6,000	$25.000	24.167	3.45%
Constellation Energy	CEG	2004	JUN	28	6,000	$37.950	37.768	0.48%
CMS Energy	CMS	2004	OCT	7	28,500	$9.100	8.770	3.76%
Ottertail Corporation	OTTR	2004	DEC	7	2,900	$25.450	24.397	4.32%
IDACORP	IDA	2004	DEC	9	83,500	$30.000	28.796	4.18%
Ameren Corp.	AEE	2003	JAN	14	5,500	$40.500	39.107	3.56%
Cinergy	CIN	2003	JAN	31	5,700	$31.100	30.815	0.93%
American Electric Power Co.	AEP	2003	FEB	27	50,000	$20.950	20.311	3.15%
PPL Corp	PPL	2003	MAY	15	65,000	$38.250	37.001	3.38%
Consolidated Edison Inc	ED	2003	MAY	19	87,000	$39.800	39.451	0.88%
OGE Energy Corp	OGE	2003	AUG	21	4,650	$21.600	20.810	3.80%
FirstEnergy Corp	FE	2003	SEP	12	28,000	$30.000	29.010	3.41%
PSEG	PEG	2003	OCT	1	8,250	$41.750	40.455	3.20%
UNITIL	UTL	2003	OCT	23	6,524	$25.400	24.130	5.26%
Puget Energy	PSD	2003	OCT	31	4,550	$22.750	22.000	3.41%
WPS Resources Corp	TEG	2003	NOV	19	3,500	$43.000	42.202	1.89%

Company	Ticker	Year	Month	Day	Number of Shares (000's)	Price to Public	Net Proceeds	n Percent of Net Proceeds
Empire District Electric Co.	EDE	2003	DEC	11	2,000	$21.150	20.138	5.03%
TXU Corp	TXU	2002	NOV	25	30,500	$14.770	14.278	3.45%
Great Plains Energy Inc	GXP	2002	NOV	21	6,000	$22.000	21.175	3.90%
PSE&G	PEG	2002	NOV	12	15000	$26.550	25.664	3.45%
Progress Energy, Inc	PGN	2002	NOV	6	14,670	$41.900	40.857	2.55%
Puget Energy	PSD	2002	NOV	5	5000	$20.700	19.975	3.63%
Puget Energy	PSD	2002	OCT	31	5,000	$20.700	19.975	3.63%
TECO Energy, Inc	TE	2002	OCT	10	17,000	$11.000	10.659	3.20%
Duke Energy	DUK	2002	SEP	25	54,500	$18.350	17.873	2.67%
PPL Corp	PPL	2002	SEP	12	14,500	$30.500	29.505	3.37%
Ameren Corp.	AEE	2002	SEP	10	7,000	$42.000	40.573	3.52%
DQE	DQE	2002	JUN	20	15,000	$13.500	12.961	4.16%
DTE Energy	DTE	2002	JUN	19	5,500	$43.250	41.799	3.47%
FPL Group	FPL	2002	JUN	6	5,000	$56.600	54.850	3.19%
FPL Group (F)	FPL	2002	JUN	6	8,800	$50.000	48.415	3.27%
American Electric Power Co.	AEP	2002	JUN	5	16,000	$40.900	39.650	3.15%
TECO Energy, Inc	TE	2002	JUN	4	13,500	$23.000	22.310	3.09%
TXU Corp	TXU	2002	MAY	31	11,000	$51.150	49.595	3.14%
Empire District Electric Co.	EDE	2002	MAY	16	2,500	$20.750	19.868	4.44%
Cleco Corp	CNL	2002	MAY	2	1,750	$33.000	32.036	3.01%
Xcel Energy Co.	XEL	2002	FEB	28	20,000	$22.500	21.755	3.42%
FPL Group	FPL	2002	JAN	29	10,000	$50.000	48.425	3.25%
Empire District Electric	EDE	2001	DEC	4	1,750	$20.370	19.500	4.46%
Hawaiian Electric Industries	HE	2001	NOV	19	1,500	$37.700	36.190	4.17%
Alliant Energy Corp	LNT	2001	NOV	15	8,500	$28.000	26.900	4.09%
Sierra Pacific	NVE	2001	AUG	15	20,500	$15.000	14.418	4.04%
Progressive Energy	PGN	2001	AUG	14	11,000	$40.000	38.600	3.63%
WPS Resource Corp	TEG	2001	MAY	2	2,000	$34.360	33.160	3.62%
Reliant Resources, Inc	RRI	2001	APR	30	52,000	$30.000	28.500	5.26%
Aquila, Inc		2001	APR	27	12,250	$24.000	22.620	6.10%
Utilicorp United Inc		2001	APR	27	5,250	$24.000	22.620	6.10%
Allegheny Energy Inc	AYE	2001	APR	26	12,400	$48.250	46.800	3.10%
Black Hills Corporation	BKH	2001	APR	18	3,000	$52.000	49.140	5.82%
Constellation Energy	CEG	2001	MAR	21	12,000	$39.900	39.280	1.58%
Duke Energy	DUK	2001	MAR	13	25,000	$38.980	37.947	2.72%
Utilicorp United Inc		2001	MAR	9	10,000	$29.760	28.940	2.83%
TECO Energy, Inc	TE	2001	MAR	6	7,500	$27.750	26.883	3.22%
CMS Energy	CMS	2001	FEB	23	10,000	$29.750	29.560	0.64%
Allete	ALE	2001	JAN	24	6,500	$23.680	22.679	4.41%
CMS Energy	CMS	2000	OCT	16	11,000	$18.250	17.770	2.70%
TNPC		2000	OCT	4	24,000	$21.000	19.790	6.11%
NRG Energy Inc.	NRG	2000	MAY	30	28,170	$15.000	14.100	6.38%
Southern Company	SO	2000	DEC	7	25,000	$28.500	27.560	3.41%
AVERAGE								3.67%

Source: Public Utility Finance Tracker through 2007; Bloomberg data from 2008 to present.

MDU Resources Group		2002	NOV	29	2,100	$ 24.000	23.188	3.50%
MDU Resources Group		2002	NOV	19	2,100	$ 24.000	23.280	3.09%

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Wyoming

Docket No. 20004-___ER-09

Direct Testimony
of
Garret Senger

Q. **Would you please state your name, business address and position?**

A. Yes. My name is Garret Senger and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Vice President - Controller and Chief Accounting Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. and Great Plains Natural Gas Co., also a Division of MDU Resources Group, Inc.

Q. **Would you please describe your duties?**

A. As Controller and CAO, I am responsible for providing the direction and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota and Great Plains.

Q. **Would you please outline your educational and professional background?**

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and a Masters in Business Administration. I started my career with Montana-Dakota in 1985 as a financial analyst in the Financial Reporting area and during my tenure with the company have held positions of increasing responsibility, including Supervisor of Financial Reporting, Manager of Financial Forecasting, Manager of Financial Reporting & Planning, Director of Accounting and Controller.

Q. **Have you testified in other proceedings before regulatory bodies?**

A. Yes, I have submitted written testimony in proceedings before this Commission, the South Dakota Public Utilities Commission and the Montana Public Service Commission.

Q. **Are you familiar with the territory served by Montana-Dakota and the facilities of the Company utilized in providing electric service?**

A. Yes, I am.

Q. **What is the purpose of your testimony in this proceeding?**

A. I am responsible for presenting Statement A, Statement B, and Statement F.

Q. **Were these statements and the data contained therein prepared by you or under your supervision?**

A. Yes, they were.

Q. **Are they true to the best of your knowledge and belief?**

A. Yes, they are.

Q. **Would you describe Statement A and Statement B?**

A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2007 and December 31, 2008, with notes to the balance sheet provided as pages 3 through 53. Statement A also includes Montana Dakota's balance sheet as of March 31, 2008 and March 31, 2009 which is provided on pages 54 and 55 with notes to the balance sheet provided as pages 56 through 79. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2008 and twelve months ending March 31, 2009. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. Would you please explain Statement F?

Statement F shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2008 and the pro forma capital structure for 2009. Statement F includes the associated costs of debt, preferred stock and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 9.620%. The basis for the requested 12.750% return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. J. Stephen Gaske.

Page 1 of Statement F summarizes the actual electric utility capital structure at December 31, 2008 and the projected capital structure and the related utility costs of capital for 2009. As shown on page 1, the components of the 2009 projected overall annual rate of return, which are used by Ms. Mulkern to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	3.054%
Short Term Debt	0.105%
Preferred Stock	0.115%
Common Equity	6.346%
Required Rate of Return	9.620%

The debt costs reflected on Statement F, page 1 represent the actual weighted embedded costs of the long-term debt at December 31, 2008 and that projected to be outstanding at December 31, 2009 and is supported by Statement F, Schedule F-1. In calculating the debt costs the "Yield-to-Maturity" method (also referred to as the Internal Rate of Return ("IRR") method) is used to determine the total cost for each respective debt issue as presented on Schedule F-1, page 2 of 5 and page 3 of 5. The yield-to-maturity calculation of each debt issue outstanding gives consideration to the stated rates of interest being paid on such debt, the timing of the interest payments, related issuance expenses, underwriters' commissions and indenture revision costs, the discount or premium realized upon issuance and the amortization of losses on bond redemption transactions.

Statement F, Schedule F-2, supports the cost of Montana-Dakota's preferred stock capital, representing the weighted cost of the issues at December 31, 2008 and projected to be outstanding at December 31, 2009.

Statement F, Schedule F-3, supports the Company's utility common equity balance at December 31, 2008, and the projected balance for 2009.

Q. **What does Statement F, Schedule F-1 show?**

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2008 and cost of debt, and it shows the projected long-term debt and costs for 2009. Page 2 shows the cost and the debt balance by issue at December 31, 2008, and page 3 shows the projected cost and the debt balance by issue at December 31, 2009.

Q. **How did you derive the projected cost of debt as for 2009?**

A. The projected cost of debt for 2009 is based upon the yield to maturity of each debt issue outstanding.

Q. **Would you please describe Statement F, Schedule F-1, page 4 and explain the amortization method utilized?**

A. Page 4 reflects the detail by issue of the annual amortization of net discounts (losses) on advance purchases of debt that are necessary to meet sinking fund requirements. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues, the same calculation as is used by the Company for accounting purposes.

Q. **Would you please describe Statement F, Schedule F-1, page 5?**

A. Page 5 presents the projected average short term debt balance for 2009 as well as the average cost of short term debt. A twelve month average of short term debt is used in the cost of capital calculation to reflect the seasonality in the short term debt balance. Short term debt is historically at or near its peak in December and the twelve month average calculation is more reflective of the borrowing level than a year end balance.

Q. What does Statement F, Schedule F-2 show?

A. Page 1 presents the preferred stock balances at December 31, 2008 and the projected balances for December 31, 2009. The anticipated weighted cost of preferred stock is also shown. Page 2 sets forth the various preferred stock issues outstanding at December 31, 2008 and page 3 sets forth the projected issues outstanding at December 31, 2009.

Q. What does Statement F, Schedule F-3 show?

A. Page 1 presents the common equity balance at December 31, 2008 and the projected balance for 2009 reflecting the pro forma activity in the balance.

Q. What does Statement F, Schedule F-4 show?

A. Page 1 indicates that, on July 26, 2006 MDU Resources Group, Inc. issued 60.2 million additional shares of common stock in connection with a three-for-two stock split at a par value of $1.00.

Q. Would you please describe Statement F, Schedule F-5?

A. This schedule presents various financial and market data relative to the Company's common stock for the years 2004 through 2008, and for each month of the twelve month period ended December 31, 2008

Q. Would you please describe Statement F, Schedule F-6?

A. This schedule shows the reacquisition activity for long term debt in the last five years and shows a summary of scheduled retirements of preferred stock for the five years ended December 31, 2008.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PUBLIC SERVICE COMMISSION OF WYOMING

JAN 19 2010

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A GENERAL RATE INCREASE IN ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING OF $70,918,825 PER ANNUM OR AN AVERAGE OVERALL INCREASE OF 13.7 PERCENT	)	DOCKET NO. 20000-352-ER-09 RECORD NO. 12310

PRE-FILED DIRECT TESTIMONY OF

Kimber M. Wichmann

On Behalf of the Wyoming Office of Consumer Advocate

Testimony Filed: January 19, 2010
Hearing Begins: February 23, 2010

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Kimber Wichmann. My business address is 2515 Warren Avenue, Suite 304, Cheyenne, WY, 82002. I am a Rate Analyst for the Wyoming Office of Consumer Advocate (OCA). The OCA is an independent consumer advocacy agency that was created by an act of the legislature in the 2003 general session.

Q. WHAT IS THE FUNCTION OF THE OCA?

A. Pursuant to W.S. § 37-2-401,

> The office of consumer advocate shall represent the interests of Wyoming citizens and all classes of utility customers in matters involving public utilities. In the exercise of its powers the office of the consumer advocate shall consider all relevant factors, including, but not limited to, the provision of safe, efficient and reliable utility services at just and reasonable prices.

Q. ARE THE ANALYSES AND RECOMMENDATIONS OF THE OCA, IN THIS OR ANY OTHER CASE BEFORE THE COMMISSION, INFLUENCED OR DIRECTED BY THE COMMISSION?

A. No. Although the OCA is a division within the Commission according to W.S. § 37-2-401, it is a separate division with no reporting or supervisory links to the Commission. The OCA has the right under W.S. § 37-2-402(ii) to appeal decisions of the Commission. The primary link between the OCA and the Public Service Commission is the source of common funding provided by the assessment on gross utility operating revenues; this assessment funds both the Commission and the OCA.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND OCCUPATIONAL EXPERIENCE.

A. I received a B.S. degree with a double major in Economics and Political Science from The Colorado College and an M.B.A. degree from the University Of Phoenix. While achieving my undergraduate degree, I worked part-time for a statewide rural electric association (REA), which gave me the opportunity to learn about electric cooperatives and the energy industry as well as the members they serve. After college, I accepted a marketing and media position with Sumpter Electric Cooperative in Sumpterville, Florida. While there, I learned the financial operations of the company while compiling the annual report and gained a good understanding of the power of marketing for safety and awareness campaigns.

In 1997, I accepted a position with the Wyoming Department of Employment Department of Research and Planning (R&P) in the capacity of Statistician. I assisted the team in gathering employment statistics for businesses throughout Wyoming. I learned the statistical modeling used by the Bureau of Labor Statistics for the Current Employment Statistics and Labor Market Information provided by the State of Wyoming.

In 1998, I left the R&P office as a Senior Statistician and accepted a position with eBay, Inc. as a Business and Process Analyst for the Consumer Experience department. While at the internet company, I gained 10 years experience in identifying, documenting, implementing, and measuring the performance of cost effective processes and informational system improvements on a global scale using data sampling and statistical modeling techniques. As a lead worker, I established baselines, identified key metrics for measuring project success, and tracked performance in a timely manner for senior management. In 2008, I left eBay as a Lead Senior Business Analyst and accepted a position as a Rate Analyst for the Wyoming Office of Consumer Advocate, where I remain employed today.

Last Summer I attended the 51st Regulatory Studies Program, which is an intensive regulatory boot camp sponsored by the Institute of Public Utilities and Michigan State University.

Q. ON WHOSE BEHALF DO YOU APPEAR HERE TODAY?

A. I appear here today on behalf of the OCA. As I indicated previously, the OCA is an independent party in this proceeding, separate and apart from the Commission or its advisory staff.

Q. AS A MEMBER OF THE OCA, DO YOU ADVOCATE THE INTERESTS OF CERTAIN GROUPS OF CONSUMERS OVER OTHERS?

A. No. As a member of the OCA, it is my statutory obligation to advocate the best interest of all citizens in the state. Specifically, W.S. § 37-2-401 states that the OCA "shall represent the interests of **<u>Wyoming citizens and all classes of utility customers</u>** in matters involving public utilities." This public interest standard requires the OCA to represent the broadest possible utility consumer constituency, even though some of those consumers may also be represented independently as parties in this case.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring Exhibits KMW1 through KMW7 which detail key points in my analysis.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide an analysis of Montana Dakota Utilities (MDU) cost of common equity capital and determine the overall rate of return for the Company's electric utility operations in the state of Wyoming that is in the public interest. My second objective is to review the Company's recommended cost of capital financing as presented through the testimony of the Company's witnesses Dr. Gaske and Dr. Senger.

Q. WHAT RATE OF RETURN IS OCA RECOMMENDING IN THIS DOCKET?

A.

Source	Balance	Ratio	Cost	Required Return
Pro Forma				
LT Debt	$280,505,118	44.96%	6.79%	3.05%
ST Debt	$17,287,362	2.77%	3.77%	0.10%
Preferred Stock	$15,600,000	2.50%	4.59%	0.11%
Common Equity	$310,520,102	49.77%	10.40%	5.18%
Total	$623,912,582	100.00%		8.45%

Based on the test period capital structure presented by the Company, I am recommending the capital structure in the table above. The overall allowed rate of return of 8.45% includes a 10.40% Cost of Common Equity.

Q. **HOW DID YOU CONDUCT YOUR COST OF CAPITAL ANALYSIS IN THIS CASE?**

A. I began my analysis by creating a proxy group of companies, from financial data that was publicly available and comparable to the regulated electric operations of Montana Dakota Utilities (MDU). This step was necessary because the electric utility operations of MDU encompass only 4% of the parent company's revenues. The risk associated with the parent company is not indicative of the risk associated with the regulated electric utility operations of MDU. Thus, a proxy group of regulated electric utilities is required.

The selection of companies to include in my proxy group started with a list of all the electric companies from Value Line. Value Line publishes a weekly investment survey that contains ratings and reports for approximately 1,700 stocks in over 90 industries, one of which is the electric utility industry. I documented the 56 companies listed in the Value Line Investment survey for the electric utility industry. These companies are documented in Exhibit KMW1.

At the time I conducted my research, I used the following weekly issues of Value Line to build the electric utility universe of companies:

- Issue 1 for the Electric Utility (East) Industry dated August 28, 2009
- Issue 5 for the Electric Utility (Central) Industry dated September 25, 2009
- and Issue 11 for the Electric Utility (West) Industry dated August 7, 2009.

Once the universe was established, I removed MDU Resources Group from the sample and used the Issuer Rate posted online from Moody's to keep only those companies that had the same issuer letter rating as MDU Resources.

Moody's had the most current issuer rating information so the information from Moody's leads my analysis.

The issuer rating allows an analyst to categorize the credit risk of companies in a manner that recognizes the unique circumstances of individual companies. The Issuer ratings are categorized by letter and number combinations that signify degrees of credit worthiness. I focused upon the letter categorization for my analysis.

In April 2009, Moody's changed MDU's Issuer Rating from A3 to Baa1. Thus I narrowed the proxy group to only include companies with a Baa rating. Keeping only those companies with a Baa rating ensures the comparability of the proxy group to MDU consistent with the requirements of "Hope" and "Bluefield," which are two legal cases that I will discuss in greater detail on page 8 of my testimony.

For the two companies that did not have an Issuer Rating on Moody's, I looked at the Issuer Rating online given by Standard's & Poors (S&P). S&P was a less desirable source of issuer ratings as its information was not as current as Moody's. Thus, some of the issuer ratings in Exhibit KMW2 seem to provide conflicting results, when in reality the ratings from S&P are not as current as Moody's.

I discovered that the Issuer Ratings for the two companies in the proxy group that were missing a rating on Moody's were not at the same investment grade as MDU, which means they did not have the same letter rating for their credit worthiness so they were dismissed from the sample. At this point the sample narrowed from 55 companies to 39 companies.

The remaining companies had revenues attributable to regulated electric operations ranging from 4-100%. Although MDU Utility is 4% of MDU Resources' overall revenue, that is not a factor when selecting the proxy group. The purpose of the proxy group is to determine a fair cost of capital for a regulated electric utility.

Setting the percentage of revenues attributable to regulated electric operations for the proxy group involves judgment. My goal was to find the companies that were most representative of the electric industry risk. I wanted companies that had a comfortable majority of revenues attributable to regulated electric operations without being overly constrictive to the proxy group.

My analysis selected only those companies that had at least 70% of revenues attributable to Regulated Electric operation as I didn't want to unnecessarily restrict the number of companies included in the proxy group. I set the filter for regulated electric revenues at 70% to allow for a bigger proxy group that is still representative of regulated electrical companies while being comparable to MDU.

I found the company specific information on revenues attributable to regulated electric operations available in the AUS Monthly Utility Report publication dated October 2009. This narrowed the sample from 39 to 23 companies and these can be viewed on Exhibit KMW2.

My final filter for the proxy group was that all the companies had to pay out dividends in 2009. This narrowed the sample from 23 to 22 companies, eliminating El Paso Electric from the list. The final proxy group can be viewed on Exhibit KMW3.

Q. ARE THE PROXY COMPANIES IN DR. GASKE'S TESTIMONY INCLUDED IN YOUR PROXY GROUP?

A. All but one of the companies that Dr. Gaske includes in his proxy group are included in OCA's proxy group. Dr. Gaske's proxy group contains 13 companies where OCA's proxy group has 22. All the companies that Dr. Gaske used in his analysis are included in my analysis with the exception of Southern Company. Moody's rated MDU as a Baa1 and Southern Company as an A3. MDU and Southern Company are not of the same investment grade quality thus Southern Company was not included in the proxy group for my analysis.

Although the majority of Dr. Gaske's proxy group is within my proxy group the methods that I used in deriving my proxy group is quite different from that used by Dr. Gaske. It is important to understand the significance to the differing methodologies as this plays into the judgments made later in the analysis. My analysis required the Issuer Rating for the comparable companies to have the same letter rating, where Dr. Gaske did not. My reasoning is to have a proxy group that is representative of the regulated electric industry that is at the same credit worthiness grade as MDU. Including companies that have a higher or lower issuer letter rating unnecessarily skews the results of the proxy group making it less comparable.

In addition, OCA set the filter for regulated electric revenues at 70% to allow for a larger proxy group which also reduces the margin of error any one company has on the overall results of my analysis. Dr. Gaske set the filter to 85%. Setting the judgment bar at 85% as Dr. Gaske did unnecessarily restricts the number of companies included in the proxy group. Thus less market information is included in the overall analysis which can increase the margin of error throughout the analysis.

Q. WHY IS IT IMPORTANT TO SELECT A GROUP OF COMPARABLE COMPANIES?

A. Two legal cases have set the fundamental standards for rate making which include selecting a comparable group of companies. The two cases are the <u>Federal Power Commission v. Hope Natural Gas Co.</u> (Hope) and <u>Bluefield Waterworks & Improvement</u>

Co. v. Public Service Commission of West Virginia (Bluefield). In Bluefield the Supreme Court found:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties;....[1]

In Hope the Supreme Court found:

> .....the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[2]

The precedent set by these decisions is that the returns authorized by regulatory authorities must be commensurate with those being earned by similarly situated companies under comparable circumstances and must provide the utility with the financial ability to attract and maintain capital.

Q. ONCE THE PROXY GROUP WAS ESTABLISHED WHAT WAS THE NEXT STEP OF YOUR ANALYSIS?

A. There are three general methods available to measure the cost of equity: Discounted Cash Flow (DCF), Risk Premium, and Capital Asset Pricing Model (CAPM). I decided to conduct my analysis using a combination of models that maximize the strengths and minimize the weaknesses of the calculations while including commonly known adjustments to account for the stakeholder interests. This provided a range of reasonableness that was later narrowed using informed judgment related to MDU's financial and business risks to determine the recommended cost of equity and overall rate of return.

Looking at the financial models available, I settled on DCF, Non Constant Growth Discounted Cash Flow (NCDCF), and CAPM models. Each model requires the exercise of considerable judgment regarding the reasonableness of the assumptions underlying the theory and on the reasonableness of the proxies used to apply the method. I attempted to use all relevant evidence known and available to me, in order to minimize judgmental, measurement, and conceptual error. I will discuss in more detail the reasons I selected this set of calculations.

The first calculation was a traditional annual DCF with a flotation adjustment. A flotation cost factor allows a company to factor in the cost of issuing and maintaining equity as part of the cost of equity rather than assuming the market price already compensates for that factor. The flotation adjustment is acceptable in this case as OCA recognizes that MDU has securities outstanding and MDU will be issuing $1 billion of securities over the next two years.[3]

The traditional DCF calculation is a commonly used model in rate cases that assumes a constant growth rate of dividends into perpetuity. Dividends do not grow at a constant rate year after year and that risk is a factor that needs to be accounted for in investor expectations. Thus the non-constant growth (NCDCF) model was included to mitigate the assumptions inherent in the DCF model. The NCDCF model provides a more realistic estimate of future growth rates by incorporating two stages of growth into its calculation. Dr. Morin, an expert witness in regulatory matters before numerous federal and state boards as well as a seasoned consultant for several Fortune 500 corporations regarding financial management and corporate litigation, explains the two-stage model:

> *"The two-stage DCF model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the next 5 years, (Stage 1 Growth), and to converge to an expected steady-state long-run rate from year 6 onward (stage 2 Growth)."*[4]

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[1] Bluefield Waterworks & Improvement Co. vs. Public Service Commission of West Virginia, 262 U.S. 679 (1923)
[2] Federal Power Commission vs. Hope Natural Gas Co., 320 U.S. 591 (1944)
[3] Docket numbers 30013-206-GS-08 and 20004-74-ES-08
[4] Morin, Roger Dr., New Regulatory Finance (2006), p.309

Including the NCDCF model tempers the results found in the traditional DCF model since empirical evidence indicates that dividend growth does not occur at a constant rate forever. One concern of the NCDCF as I have employed it in my analysis in this case, is that it is very dependent on a single data source, Value Line, for its calculation. Having three separate calculations with differing inputs minimizes this concern.

The final model I used was the Capital Asset Pricing Model (CAPM). The purpose of this model is to provide an objective measure of risk for regulated electric utilities of the same investment grade as MDU relative to other securities. I selected the CAPM because the calculation analyzed the regulated industry through the use of Beta. Being a regulated industry does impact the ROE. Regulated companies perform differently than companies which operate in competitive markets.

In practice the CAPM is a refinement of the traditional risk premium method that attempts to measure the risk inherent in individual securities relative to all other securities on the market. As such I did not rely on the results of the traditional Risk Premium (RP) model but instead considered the results of the CAPM which in my view more accurately captures the risk associated with regulated utilities.

Together the three calculations mentioned above provided a range of reasonableness that captures risk while providing an estimated range for cost of equity that represents investors' expectations.

Q. HOW DID YOU CONDUCT YOUR DCF ANALYSIS?

A. I began my analysis by examining at the traditional DCF equations. The traditional annual constant growth DCF calculation[5] is:

$$\mathbf{K = D_1 / P_0 + g}$$

Where: K = Cost of Equity
D_1 = Dividend in Period 1

[5] Morin, Roger Dr., New Regulatory Finance (2006), p.254

P_0 = Current Stock Price
g = expected growth in dividends

A key theoretical assumption of this model is that dividends will grow at a constant rate in perpetuity.

I included a flotation allowance in my analysis. Thus the calculation[6] I use is:

$$K = D_1 / P_0 (1-f) + g$$

Where: K = Cost of Equity
D_1 = Dividend in Period 1 (Average of the Value Line's 2010 Dividend Projections for the proxy group)
P_0 = Current Stock Price (Spot stock price for proxy companies on 11/12/2009 from the Wall Street Journal)
g = expected growth in dividends (Average of the 5-year earnings growth rate from Value Line, Zack's, and Yahoo! Finance)
f = flotation cost factor (The percent of Net Proceeds from MDU Resources Group's November 29, 2002 issuance as detailed in Dr. Gaske's Exhibit JSG-2)

The data for the proxy groups and the results of the calculation of the traditional annual constant growth DCF model with flotation costs can be viewed on Exhibit KMW4 in the last column. The cost of equity, for my proxy group, that results from the calculation above is 10.93%.

Analysts differ in the approach to derive the dividend in period 1, stock price, growth, and flotation cost adjustment for the DCF formula. As a rule, I used the Value Line analyst information when it was available since there is empirical research[7] supporting Value Line analysts' growth forecasts.

Approach to the elements in the calculation

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[6] Morin, Roger Dr., New Regulatory Finance (2006), p.283
[7] Important papers include Brown, Lawrence D. and Rozeff, Michael S., The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings. Journal of Finance, Vol. 33, No. 1, March 1978.
J. G. Cragg, J.G. and Malkiel, Burton G., The Consensus and Accuracy of Some Predictions of the Growth of Corporate Earnings. The Journal of Finance, Vol. 23, No. 1 (Mar., 1968), pp. 67-84.
Vander Weide, J. H., and W. T. Carleton. "Investor Growth Expectations: Analysts vs. History." The Journal of Portfolio Management, Spring 1988, pp. 78-82.
Lys, Thomas and Sungkyu Sohn. 1990. The association between revisions of financial analysts' earnings forecasts and security price changes. Journal of Accounting and Economics. 13(4): 341-363.

For the dividend in period 1, I used Value Line's 2010 Dividend Declared per Share projection for the proxy companies. Because I am attempting to measure the present value of investors' future return expectations the theory underpinning the DCF model requires that I use the estimated dividend in the next future period rather than the current dividend to derive the current dividend yield. Using the prospective dividend also prevents any downward bias in the dividend yield. This is important so the cost of equity is not underestimated.

The 2010 projected dividend per share information taken from Value Line is shown on Exhibit KMW4. The data is located in column three titled: Value Line projected 2010 Dividend Per Share. The data from that column was used as D_1 for each of the companies in the proxy group in the final calculation on the spreadsheet.

Stock Price

I used the current stock price form the November 12, 2009 Wall Street Journal website which was the most current price available at the time I conducted my analysis. I believe in the Efficient Market Hypothesis[8] that states the most relevant stock price is the most recent stock price. In my view historic share prices are irrelevant to investors' current expectations and their use in the DCF model, even on an average basis, produces unreliable results and violates the rule of market efficiency.[9] My approach balances the fact that the period used in measuring the dividend yield portion of the formula must be consistent with the growth portion of the formula. The current stock price from the Wall Street Journal for the proxy group is located on Exhibit KMW4 in the column titled: Stock Price WSJ 11/12/09. The data in that column was used as P_0 in the calculation for each of the proxy companies in the final calculation on the spreadsheet.

Growth

John C. Easterwood & Stacey R. Nutt, 1999. "Inefficiency in Analysts' Earnings Forecasts: Systematic Misreaction or Systematic Optimism?," Journal of Finance, American Finance Association, vol. 54(5), pages 1777-1797, October.

8 The Efficient Market Hypothesis, E. Fama. Efficient capital markets: a review of theory and empirical work. Journal of Finance, 25:383–417, 1970.

9 Morin, Roger Dr., New Regulatory Finance (2006), p.279 Empirical evidence: Reilly and Brown (2003)

Analysts differ in their approaches to measuring growth. There are three general approaches an analyst has available to measure growth: historical growth rates, analysts' forecasts and sustainable growth rates. Empirical research[10] appears to support analysts' growth forecasts rather than historical time series forecasts, in relation to cost of capital studies. Thus, I used analysts' forecasts for growth.

My analysis uses the average of analysts' 5-year earnings growth forecasts' from Value Line, Yahoo! Finance, and Zack's. The earnings growth rate was used from these sources because empirical research supports the use of earnings. Additionally it was difficult to find dividend growth rates from all the sources. Furthermore, corporate dividend policies are subject to change over time.[11]

The data for the 5-year earnings growth rate was entered and averaged from Value Line, Zack's, and Yahoo! Finance for the proxy group. The averaged growth is on Exhibit KMW4 in the second to last column titled: Average Earnings growth (EG). The data in that column was used as 'g' in the final calculation on the spreadsheet.

Flotation costs

The flotation cost factor was the last piece to consider before completing the calculation. The OCA supports a flotation cost adjustment in this case as it is necessary to keep a company whole. A flotation cost adjustment allows a company to factor in the cost of issuing and maintaining equity as part of the cost of equity rather than assuming the market price already compensates investors for that cost.

My approach to the flotation cost factor was to reference Dr. Gaske's Exhibit JSG-2 Schedule 3. Dr. Gaske's exhibit details the average of the electric companies' issuance costs in relation the net proceeds of the issuance. In addition, the exhibit details the issuance costs from MDU Resources Group's 2002 issuance.

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[10] Important papers include Brown and Rozeff (1978), Cragg and Malkiel (1968, 1982), Harris (1986), Vander Weide and Carleton (1988), Lys and Sohn (1990), and Easterwood and Nutt (1999)

[11] Board members of companies decide the dividend policy for the companies they represent and the board members change over time.

As an advocate for Wyoming consumers, I used the flotation factor that promoted efficiency in its calculation. MDU's flotation factor was 3.50% which was lower than the industry average in Dr. Gaske's exhibit.

MDU's flotation factor being lower than the industry average reveals that the Company is more efficient than the industry in regards to issuance costs. It would be unfair to customers to use the industry average when the company costs are known and less than the average.

Flotation costs are not something to profit from, but rather a means to make the company whole in the DCF calculation. The OCA used MDU's issuance cost of 3.50% for 'f' in the calculation above. The result was that the Return on Equity (ROE) was 20 basis points higher than if the flotation cost factor had not been used. The flotation costs are embedded in the final calculation in the last column on Exhibit KMW4.

Results

The cost of equity that resulted for the traditional annual constant growth DCF model with a flotation adjustment was 10.93%. The results are posted in the last column of Exhibit KMW4.

Q. HOW DID YOU CONDUCT YOUR NCDCF ANALYSIS?

A. I began my analysis by looking at the NCDCF equation[12].

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \;\cdots\cdots\; \frac{D_n}{(1+K)^n} + \frac{D_n(1-g)}{K-g} \times \frac{1}{(1+K)^n}$$

Where: K = Cost of Equity
$D_1, D_2 \ldots D_n$ = Expected dividends in each year
P_0 = Current stock price
g = Constant growth rate beyond year 5
K = required return on equity

[12] Morin, Roger Dr., New Regulatory Finance (2006), p.264

Since the growth rates in the traditional annual constant growth DCF model were for 5 years, I elected a two-stage NCDCF calculation that incorporates a first-stage growth estimate for 5 years as well. Thus, the equation for NCDCF looks like this:

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \frac{D_3}{(1+K)^3} + \frac{D_4}{(1+K)^4} + \frac{D_5}{(1+K)^5} + \frac{D_5(1-g)}{K-g} \text{ X } \frac{1}{(1+K)^5}$$

Where: D_1, D_2, D_3, D_4, D_5 = Expected dividends in each year. D_1 and D_5 are from Value Line. D_2 through D_4 are imputed from the Value Line information.
P_0 = Current stock price. Spot stock price for proxy companies on 11/12/2009 from the Wall Street Journal.
g = Constant growth rate beyond year 5. The calculated retention ratio from 2014 multiplied by the Value Line projected Return on Equity for 2012-2014.
K = required return on equity

The purpose is to solve the equation for K, which is the required ROE. The data for the proxy groups and the results of the calculation of the NCDCF model can be viewed on Exhibit KMW5. The cost of equity for my proxy group that results from the calculation above is 9.81%, however adding the flotation adjustment brings the cost of equity to 10.01%.

Growth

For the first stage of the model I used the sustainable growth method often called the "retention ratio method" to estimate the growth rate that I expect to persist during the initial five year period. Using this method the fraction of earnings expected to be retained by the company is multiplied by the expected return on equity during the initial five year period to produce the annual growth rate.

The calculation for the sustainable growth[13] is:

$$g = b \times r$$

Where: b = fraction of earnings expected to be retained
r = expected return on equity
g = future growth in earnings

Solving future growth in earnings (g)

[13] Morin, Roger Dr., New Regulatory Finance (2006), p. 303

Before starting on the NCDCF calculation 'g' had to be known and to do that required calculating the retention ratios for 2010-2014. The first step for the sustainable growth calculation was to determine the earnings and dividends per share for 2010 – 2014. Value Line projects dividends and earnings for 2010 and 2014 in the Investment Survey. Thus the implicit earnings and dividends values for years 2011-2013 were calculated by spreading the difference in projected dividends per share between 2010 and 2014 evenly over the intervening years. The results are shown in exhibit KMW5 under the columns titled: Value Line DY 2010, Imputed DY 2011, Imputed DY 2012, and Imputed DY 2013, and Value Line DY 2014.

Fraction of earnings expected to be retained (b)

The second step was calculating the retention ratio. The analysis took the dividend per share yield for a given year and divided it by the earnings per share for the same given year and arrived at the retention ratios for 2010-2014. The data is on Exhibit KMW5 under column titles: Retention Ratio 2010, Retention Ratio 2011, Retention Ratio 2012, Retention Ratio 2013, and Retention Ratio 2014. This data was used as 'b' for each of the proxy companies for to calculate the Sustainable Growth Rate, which has its own column on Exhibit KMW5.

Projected ROE (r)

For the second stage of the NCDCF model I assumed that dividends would grow at a constant perpetual rate beginning in 2014 and thereafter. Value Line provides the projected ROE for all the proxy companies for 2014 and the data was added into exhibit KMW5 under the column titled: Value Line ROE 2012-14. The 2014 ROE projection functions as 'r' in the NCDCF calculation located on the second to last column on Exhibit KMW5. The sustainable growth rate is then calculated by multiplying the 2014 retention rate by the 2014 ROE. The results of the calculation are available in Exhibit KMW5 under the column titled: Sustainable Growth Rate.

Since 'g' has been calculated for each of the proxy companies and the data has been documented under the sustainable growth rate column in Exhibit KMW5 the analysis returns to the NCDCF calculation which is:

$$P_0 = \frac{D_1}{1+K} + \frac{D_2}{(1+K)^2} + \frac{D_3}{(1+K)^3} + \frac{D_4}{(1+K)^4} + \frac{D_5}{(1+K)^5} + \frac{D_5(1\text{-}g)}{K\text{-}g} \times \frac{1}{(1+K)^5}$$

Where: D_1, D_2, D_3, D_4, D_5 = Expected dividends in each year. D_1 and D_5 are from Value Line. D_2 through D_4 are imputed from the Value Line information.
P_0 = Current stock price. Spot stock price for proxy companies on 11/12/2009 from the Wall Street Journal.
g = Constant growth rate beyond year 5. The calculated retention ratio from 2014 multiplied by the Value Line projected Return on Equity for 2012-2014.
K = required return on equity

D_1, D_2, D_3, D_4, D_5 were calculated during the sustainable growth equation, which determined the earnings and dividends per share for 2010 – 2014. The data is on exhibit KMW5 under the columns titled: Value Line DY 2010 (D_1), Imputed DY 2011 (D_2), Imputed DY 2012 (D_3), and Imputed DY 2013 (D_4), and Value Line DY 2014 (D_5).

Stock Price

The OCA used the current stock price form the November 12, 2009 Wall Street Journal website at the time of its analysis for all the same reasons mentioned when using the annual constant growth version of the DCF model. The final element to enter into the equation was 'g.'

Results

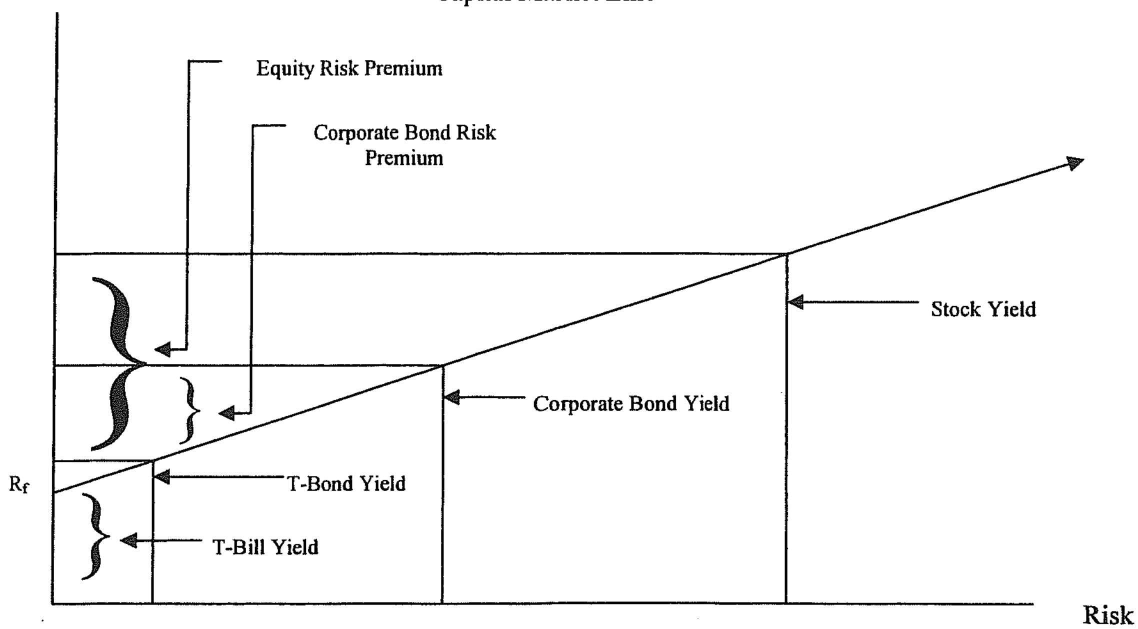
The resulting Cost of Equity from the NCDCF model was 9.81%. I then added a flotation cost adjustment identical to the flotation cost adjustment that I made in the annual constant growth DCF model. Thus the final Cost of Equity including flotation costs with the NCDCF model was 10.01%. The results for the NCDCF and the NCDCF with flotation adjustment are listed on the last two columns of Exhibit KMW5.

Q. **HOW DID YOU CONDUCT YOUR CAPM ANALYSIS?**

A. The CAPM is based on the premise that equity investors demand a premium in return for assuming the increased risk associated with investments in corporate common stock relative to less risky corporate bonds or risk free U.S. government securities. The figure below shows the risk and equity relationship between bond holders, stock holders and investors in risk free equities.

In the CAPM model, historical performance of corporate stock and bond premiums in relation to risk free investments such as US treasury bills and bonds establish the framework of what investors expect to occur in the future.

Capital Market Line



The figure above demonstrates that the more risk an investor takes the higher the equity demanded in return for that risk. R_f represents the risk free or riskless rate. The return on equity for regulated utilities, which typically have a beta of less than one, will generally fall between the risk free rate and the average yield for corporate stock. Ibbotson explains the figure above as:

> *"The riskless asset forms the y-intercept of the security market line and represents the expected return on the asset with no systematic risk (beta equal to zero). The market portfolio by definition has a beta of one. Drawing a line that passes through the riskless asset and the market portfolio forms the security market line."*[14]

My CAPM analysis looked at the current risk free premiums for US Treasury Bills and Bonds as well as the current premiums for corporate bonds and stock. The purpose is to determine the return on equity investors expect for the increased risk associated with a

[14] Ibbotson SBBI 2008 Valuation Yearbook p.58

regulated utility compared to risk free investments. Ibbotson explains the simplicity of the model:

> *"The historical equity risk premium can be calculated by subtracting the long-term average of the income return on the riskless asset (Treasuries) from the long-term average stock market return (measured over the same period as that of the riskless asset)."*[15]

The CAPM calculation[16] is:

$$K = R_F + \beta\ (ERP)$$

Where: K = Cost of Equity
R_F = Risk Free Rate
ß = Beta
ERP = Expected Risk Premium

Risk free rate

The Risk Free Rate, R_F, in my analysis consists of 3 elements: short-term risk free rate, long-term risk free rate, and corporate risk free rate. I used the U.S. 1-month Treasury Bill taken from the Wall Street Journal on December 7, 2009 for the short-term risk free rate of 0.08%, U.S. 30-year Treasury Bond taken from the Wall Street Journal on December 7, 2009 for the long-term risk free rate of 4.39%, and Mergent Bond Record Corporate Bond Yield Averages[17] for the corporate risk free rate of 5.63%. These rates are listed on Exhibit KMW6 under the columns titled: ST Risk Free Rate (US 1 month Treasury Bill 12/07/09 WSJ), LT Risk Free Rate (US 30-year Bond 12/07/09 WSJ), and Corp Risk Free Rate (Mergent Bond Record Corporate Bond Yield Averages AV. Corp Nov 2009 p.11). The data in those columns were used as R_F in the calculation for each of the proxy companies in the final 3 columns of Exhibit KMW6.

Beta

[15] Ibbotson SBBI 2008 Valuation Yearbook p.71
[16] Ibbotson SBBI 2008 Valuation Yearbook p.58
[17] Mergent Bond Record Corporate Bond Yield Averages Nov 2009 p.11

Beta, ß, is available in the Value Line publication for each of the proxy companies. Beta is the piece of the equation that brings in the regulatory factor into the calculation. Beta is calculated for every company in the Value Line Investment Survey.
Regulated utilities have a beta that is typically under the value of one. The number one represents the beta of the market as a whole. The average beta for the proxy group was 0.7.

The degree to which the share price of a specific company co-varies with variations in the share prices of the overall market is defined as its beta. The closer the beta is to one the more the share price of the company varies in tandem with average share prices for the market in total. Conversely, shares with bets coefficients more or less than one are said to vary more or less than the market in general. Data for beta is compiled in Exhibit KMW6 under the column titled: Value Line Beta.

Difference between the market risk premium and the risk free rate

The last portion of the calculation stated as **(ERP)** consists of three elements: short-term equity risk rate, long-term equity risk rate, and corporate equity risk rate. An analyst must decide to use the Arithmetic Mean or the Geometric Mean for the element.

The OCA was purposeful when it selected the Arithmetic Mean for ERP. The Arithmetic Mean represents the simple difference between the stock market returns and the riskless rates which is the most appropriate for discounting future cash flows. Since the purpose is to calculate the future equity risk premium, I selected the Arithmetic Mean. Ibbotson supports my decision by stating:

> *"The geometric average is more appropriate for reporting past performance, since it represents the compound average return."*[18]*(Ibbotson)*

Short-term equity risk premium

The short-term equity risk premium was calculated using information from Ibbotson SBBI in the 2009 Valuation Yearbook.[19] I took the Arithmetic Mean of the Large Company Stocks Total Returns (11.7%) and subtracted the Arithmetic Mean for the

[18] Ibbotson SBBI 2008 Valuation Yearbook p.77
[19] Ibbotson SBBI 2009 Valuation Yearbook p.23

Treasury Bills Total Returns (3.8%) to arrive at the Short-Term Equity Risk Premium of 7.9%. The data is on Exhibit KMW6 under the column titled: Ibbotsons ST Equity Risk Premium.

Long-term equity risk premium

The long-term equity risk premium was calculated using information from Ibbotson SBBI in the 2009 Valuation Yearbook.[20] I took the Arithmetic Mean of the Large Company Stocks Total Returns (11.7%) and subtracted the Arithmetic Mean for the Income of the Long-Term Government Bonds (5.2%) to arrive at the Long-Term Equity Risk Premium of 6.5%. The data is on Exhibit KMW6 under the column titled: Ibbotsons LT Equity Risk Premium.

Corporate equity risk premium

The corporate equity risk premium was calculated using information from Ibbotson SBBI in the 2008 Valuation Yearbook.[21] I took the Arithmetic Mean of the Large Company Stocks Total Returns (11.7%) and subtracted the Arithmetic Mean for the Long-Term Corporate Bonds Total Returns (6.2%) to arrive at the Corporate Equity Risk Premium of 5.5%. The data is on Exhibit KMW6 under the column titled: Corp Equity Risk Premium.

The CAPM equations, with the Ibbotson data that I used for the CAPM are:

Short Term CAPM	$K = R_F + \beta\ (7.9\%)$
Long Term CAPM	$K = R_F + \beta\ (6.5\%)$
Corporate CAPM	$K = R_F + \beta\ (5.5\%)$

Results

The results of my analysis are detailed in the last three columns of Exhibit KMW6. The Long Term Cost of Equity and the Corporate Cost of Equity that resulted from the CAPM Model were 9.05% - 9.58%. The short term CAPM was a benchmark for reasonableness when looking at the MDU's cost of short term debt in its capital structure in Mr. Senger's testimony.

[20] Ibbotson SBBI 2009 Valuation Yearbook p.23
[21] Ibbotson SBBI 2009 Valuation Yearbook p.23

Q. YOU HAVE ESTABLISHED A RANGE OF 9.05% - 10.93% FOR THE COST OF EQUITY USING ALL THREE METHODS. WHAT DID YOUR ANALYSIS LOOK AT NEXT?

A. Once my calculations were complete, I looked at the macroeconomic, financial, and business risks facing the regulated utility portion of MDU. I looked at the capital structure of the company to determine the reasonableness of the leverage. I also looked at the tariffs to evaluate the utility's ability to pass on significant changes in operational expenses.

Q. WHY ARE MACROECONOMIC, FINANCIAL, AND BUSINESS RISKS IMPORTANT?

A. Macroeconomic conditions pose risk in the sense that they can influence the cost of capital and the risk is beyond the control of the company.

The financial risk is the debt to equity ratio of the company, or the company structure. This structure largely determines the financial stability of the company. A financially healthy company will maintain an issuer grade. The issuer grade directly influences a company's cost of capital.

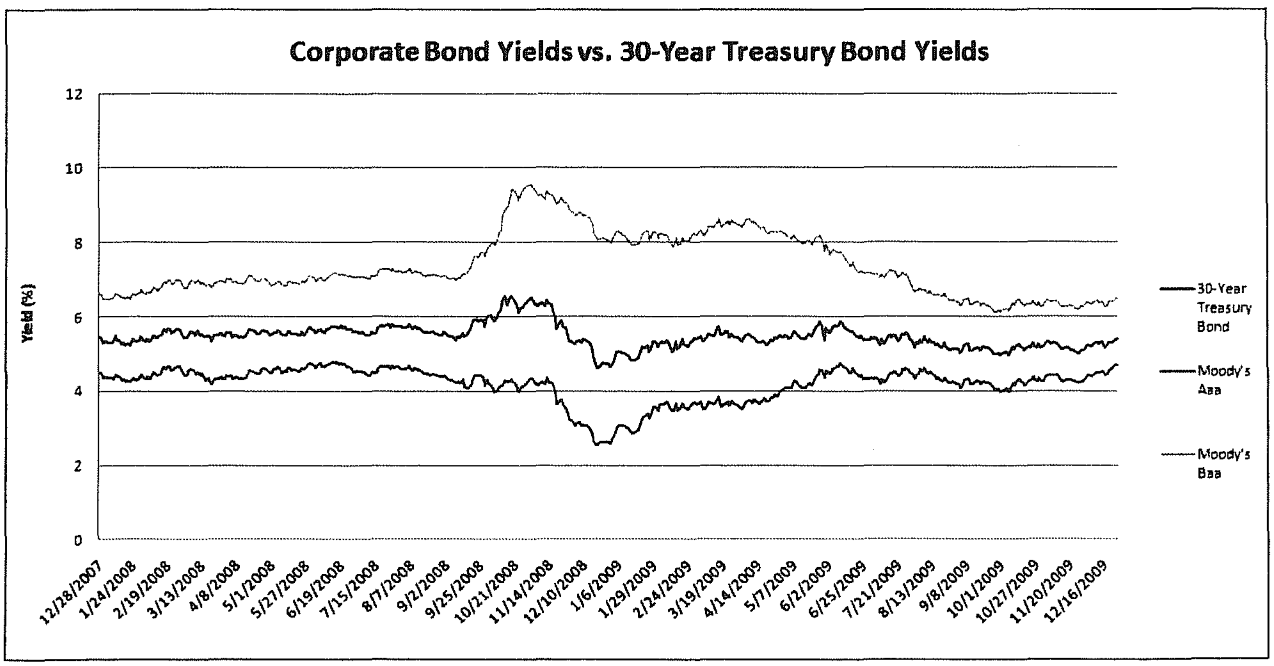
Business risk is tied to the management of the company and the consumer classes it supports. Good policies and procedures should mitigate risk by assuring revenue flows as much as possible. A large part of a utility's risk is expenses. The policies and procedures a company has in place to recover expenses that are volatile greatly measure the company's business risk. Such policies and procedures are considered by analysts when reviews and establishes the issue grade of the company. The issue grade directly influences a company's cost of capital.

Q. WHAT WERE THE MACROECONOMIC CONDITIONS YOU INVESTIGATED?

A. Knowing the U.S. economy is currently in a recession, I focused my research on credit spreads, the condition of the labor market, and Gross Domestic Product (GDP).

Q. WHAT ARE THE CURRENT CREDIT SPREADS?

A. The graph below, titled Credit spreads vs. 30-Year Treasury Yields, details the credit spread information for Aaa and Baa rated companies in comparison to 30-Year Treasury Bond yields. The data for the graph was taken from the Federal Reserve of St. Louis website.[22] Please keep in mind that utilities perform under the market value and that the graph below represents the Aaa and Baa yields of the market. However the peaks and troughs of the market which appear in the graph below impact the utility industry in the same way.



Credit spreads contracted throughout 2009. The gap between Baa credit spreads and the 30-year Treasury yield has significantly narrowed and reached a stable level of approximately 200 basis points which is in the range of historic average yields. The wider

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[22] http://www.stlouisfed.org/

the gap appears on the graph, the more investors expect a premium for that grade of investment. In December of 2008, the risk premium escalated to over 560 basis points of that held by 30-year treasury assets. One year later in December 2009 the risk premium is at 180 basis points, about where it stood prior to financial market calamities that began in September 2008. The interesting insight from the graph is to see that the fluctuations which occurred earlier have leveled out. The narrowing of the gap reveals that the market has stabilized, credit spreads have decreased, and as a result investors expect less of a premium on corporate debt when compared to government debt. At this time, there is not an excessive risk in these securities and the premiums are average.

Q. WHAT IS THE CURRENT CONDITION OF THE LABOR MARKET AND GDP?

A. The Bureau of Labor Statistics (BLS) website shows that the actual number of workers active in the labor force remained relatively flat in Employment Situation Survey for November 2009. The BLS website also shows that unemployment remained steady at 10% for November and December 2009. The troubling point is that the unemployment rate is much higher than last year and historical norms which range from 3-5%.[23] . The lack of growth in the labor force would seem to give credibility to the argument that non growth in unemployment is not comforting because the numbers did not translate to growth in the labor force.

I wanted to see if GDP was slowing as the labor force seemed to suggest. The U.S Department of Commerce Bureau of Economic Analysis (BEA) website had annual Gross Domestic Product growth available through 2008 and Quarterly information for 2009 for quarters 1-3. The annual GDP information would not be available for 2009 until January 29, 2010. With the information available, I could trend the GDP annual data that showed:

GDP 30-year average: 3.0%
GDP 20-year average: 2.9%
GDP 10-year average: 2.8%

GDP 5-year average: 2.4%

In 2008, the annual GDP was 0.4%. The first 3 quarters in 2009 the GDP was -6.4, -0.7, and 2.2%. 2009's 3rd quarter was less than expected growth. On average that is a -1.6% growth per quarter. "The main factors behind the downgrade: consumers didn't spend as much, commercial construction was weaker, business investment in equipment and software was a bit softer and companies cut back more on inventories…"[24] There is no official data for 2009 4th quarter GDP yet, however mainstream media was vocal that consumer spending was less than anticipated and much less than it had been the previous year.[25]

Q. WHY ARE THE LABOR MARKET AND GDP SIGNIFICANT?

A. The labor market is a condition that signals positive or negative economic conditions. When the labor market is growing, that can signal prosperity and growth of the economy. When the labor market is shrinking or stagnant that can signal slow to minimal growth of the economy. Slow growth can indicate less investments or a slower need for investments. Less investment opportunities can translate into less competition and potentially lower premiums required by the market.

Q. WHAT LEVEL OF RISK ARE THE MACROECONOMIC CONDITIONS CONTRIBUTING TO THE COST OF CAPITAL?

A. Investors expect less of a premium on corporate debt when compared to government debt. The U.S. is in a recession and growth in the labor force and GDP remains slow. Thus the macroeconomic conditions mentioned above do not merit an excessive use of conservatism in determining the recommended cost of capital at this time. That said, there

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[23] http://www.bls.gov/news.release/empsit.nr0.htm
[24] http://www.cbsnews.com/stories/2009/12/22/business/main6009513.shtml
[25] http://www.gallup.com/poll/112723/Gallup-Daily-US-Consumer-Spending.aspx and http://www.gallup.com/poll/124475/Gallup-Economic-Weekly-Spending-Up-Pre-Black-Friday.aspx

is still a high degree of uncertainty in the financial market due to the influence of government stimulus money and the Federal Reserve keeping current interest rates low.

Q. WHAT ARE THE FINACIAL RISKS?

A. Financial risk is the amount of debt the company uses to finance its operations. Common and Preferred equity for the proxy group averaged at 47.98% and Long-term debt was at 52.02%. MDU's pro forma capital structure has 47.73% debt and 52.27% equity which is essentially the same as the proxy group. Exhibit KMW7 details the debt to equity ratios of the proxy group and the capital structure of MDU.

I reviewed Mr. Senger's capital structure and was in agreement with his calculations for debt costs. Mr. Senger uses the actual cost of debt including issuance costs and the premium/discount realized at maturity. The company submitted two capital structures. One directly from the December 31, 2008 books and the other with its known adjustments called the 'Pro Forma.' I have listed both in Exhibit KMW7, however it is my understanding the final numbers are those in the Pro Forma table.

I found that the leverage is reasonable in comparison to the proxy companies which mean the financial risk is average. Conservatism is not merited when recommending a cost of capital from the designated range due to financial risk at this time.

Q. WHAT ARE THE BUSINESS RISKS?

A. Although the national GDP is struggling all the states in the MDU service area had growth that exceeded the national average. Wyoming had the seconded highest growth in the nation at 4.4%.[26]

North Dakota, Wyoming, and South Dakota, which account for 77% of MDU's electric revenues, had the highest GDP growth in the nation. MDU sought and was granted approval for the authority to issue $1 billion worth of MDU securities over the next two years.[27] The insight from this information is that states experiencing growth will need more energy and investment from the company to sustain safe and reliable service. Rapid growth can increase risk; however the risk can be mitigated by policy.

The majority of Wyoming customers in MDU's service area are residential and small commercial. However 34% of the energy consumed by MDU's Wyoming customers is used by the industrial class. To evaluate the business risk with rapid growth in Wyoming, I reviewed the company's tariffs. I was specifically interested in the financing for new service and whether the company or the customer takes on that risk. As mentioned previously, the majority of Wyoming consumers in MDU's service area are residential and small commercial which provide more stability than a heavy industrial clientele. In addition MDU's tariffs include an Electric Extension and temporary load policies. These policies address the financing issues associated with extending service to new customers as well as the refund of monies should others utilizes the new system within 5 years after it is built. The tariffs sufficiently protect the company from the business risk associated with growth due to new customers needing service regardless of the customer class.

The tariffs provide insights into the management of the company through its policies. In particular the tariffs can assist a savvy company in mitigating business risk especially when considering growth and funding such growth. Knowing that MDU is operating in a depressed national economy, serving high growth areas, and now part owner of a power plant I wanted to understand the utility's ability to pass on significant changes in operational expenses to determine the level of business risk the utility faces.

The proposed tariffs show that MDU is increasing the base rates for customer classes to better recover fixed costs of the company. Changing the rate design so that more of the fixed costs are placed in the base rate rather than the volumetric rate means that the company collects a more reliable base amount of revenue that is independent of the volumetric usage of energy.

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[26] http://www.bea.gov/newsreleases/regional/gdp_state/gsp_highlights.pdf
[27] Dockets 30013-206-GS-08 and 20004-74-ES-08 Record 11831

The most noteworthy tracker is MDU's Power Supply Cost Adjustment (PSCA) clause which allows the company to pass-on changes in fuel and purchased power costs without a rate case. Prior to owning part of Wygen III, over 70% of MDU's expenses were fuel costs. A pass-on mechanism greatly mitigates business risk associated with the price fluctuations inherent when purchasing energy. These two tariffs significantly mitigate business risk to the company and are viewed as good management practices by the rating agencies.

Results

The tariffs mentioned above adequately address MDU's largest expenses fuel, power, and construction that face the utility on an ongoing basis. For the foregoing reasons I view the business risk faced by MDU as low to average of other utilities.

Other policies contained in the tariffs that are beneficial to the Company but have less of an effect on the expenses are a policy the past due payments are subject to late payment charges. This policy should keep uncollected balances to a minimum. MDU has a Load Management Tracking Adjustment (LMTA) clause, which allows the company to recoup expenses for its DSM programs as well as recoup the cost on energy savings. The LMTA accounts for less than 5% of the company's expenses. These policies show that management balances the public interest for initiative like DSM while keeping the company accountable for energy savings and recouping the necessary cash flows to keep the company sound. At the same time, all of these policies tend to mitigate the risk that the Company will not have a reasonable return on its invested capital. The risk reduction should certainly be considered in establishing a fair and just return for the Company.

Q. **NOW THAT YOU HAVE REVIEWED ALL THE RISKS WHAT IS YOUR RECOMMENDATION FOR THE COST OF EQUITY?**

A. Based on the analysis and evidence that I presented in my testimony it is my judgment that a fair and reasonable return for MDU should fall in the middle to upper half of my range of reasonable returns. The midpoint of my range of values would be approximately

9.90% but I am conservatively recommending that MDU be granted a 10.40% return on its equity investment. This return recognizes there are still extrinsic financial and economic elements that may work to increase the risk profile for MDU, although many of those risk factors are on a trajectory to return to normal historic levels. The capital structure is documented in Exhibit KMW7 with the table titled Pro Forma.

Q. DO YOU BELIEVE A COST OF CAPITAL OF 10.40% AND A RATE OF RETURN OF 8.45% IS JUST AND REASONABLE?

A. Yes, I believe that the return rates are just, reasonable, and uphold the public interest. Although my proposed rate of return is lower than that proposed by the company that does not make it unreasonable. Determining just and reasonable rates requires balancing both consumer and investor interests.

The OCA approaches the analysis from the perspective of what is in the interest of Wyoming consumers while recognizing that keeping the company viable is in the consumers' best interests as well.

Specific to the Rate of Return Hope states:

> *"Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base."*[28] *– Hope (10-12)*

What the company is entitled to ask is a fair return upon the value of that which it employs for public convenience.[29]

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE COMPANY'S PROPOSED COST OF CAPITAL IN THIS CASE?

[28] Federal Power Commission vs. Hope Natural Gas Co., 320 U.S. 591 (1944)
[29] Smyth v. Ames, 169 U.S. 466 (1898)

A. Upon review I see that Dr. Gaske documented three models but only uses two of the models for determining his cost of capital analysis. His work included two DCF models and a Risk Premium calculation. However, the Risk Premium analysis seemed to be informational and did not directly influence the cost of capital requested by the company.

Q. ARE THERE ASPECTS OF DR. GASKE'S CALCULATIONS WITH WHICH YOU DISAGREE?

A. Yes. I disagree with the judgments used in the DCF model in relation to the stock price and growth. In addition, I fail to see the relevance of the Risk Premium analysis to this docket.

Q. PLEASE EXPLAIN YOUR DISAGREEMENTS WITH THE DCF MODELS.

A. **Stock Price**

Averaging the stock price should only occur when the daily stock price reflects abnormal conditions. Meaning that the day the stock price was taken the result was abnormally high or low compared to the previous 10-day period. For argument, let us proceed as if I believe such conditions existed that merited the averaging of the stock price.

Options available to average stock price

When averaging a stock price there are three generally accepted methods available to an analyst a 10-day average, a 30-day average, or a 30-day high low average as described by Dr. Morin in his book titled New Regulatory Finance.[30] The options are listed in the preferred order of usage. Taking the average of the high and low price for the most recent month is acceptable providing the current day's stock price was an outlier and the 10-day average was also an outlier. Again, for the sake of argument let us proceed assuming Dr. Gaske was using an abundance of caution regarding the potential for abnormal stock price and decided averaging the stock prices was the right decision.

[30] Morin, Roger Dr., New Regulatory Finance (2006), pp. 279-281

Dr. Gaske's analysis uses the high and low stock prices from the past 6 months. The amount of time Dr. Gaske selected is arbitrary and does not reflect investors' current expectations.

The point of the DCF calculation is to measure investors' most current expectations of future dividends. Choosing to average a stock price is a judgment decision. However the longer the amount of time over which the price is averaged the less relevance it has to investors' expectations about the future and the more susceptible it is to manipulation by the enquiry analyst. The options available to average stock price are part of the science that solidifies the integrity of the theory.

Q. PLEASE EXPLAIN YOUR DISAGREEMENTS WITH THE GROWTH USED BY DR. GASKE IN HIS DCF MODELS.

A. Dr. Gaske provides a traditional DCF calculation with a random 'adjustment' that is unsubstantiated by any academic reasoning or citing.

The traditional DCF model with a flotation adjustment[31] looks like this:

$$\mathbf{K = D_1 / P_0 (1\text{-}f) + g}$$

The traditional Quarterly DCF model[32] looks like this:

$$K = \frac{[D_1(1+K)^{3/4} + D_2(1+K)^{1/2} + D_4(1+K)^{1/4} + D_4]}{P_0} + g$$

Although Dr. Gaske mentions the quarterly DCF model he does not actually use the quarterly DCF model for his calculation. Neither of the models mentioned above are used by Dr. Gaske. At best, his model could be referred to as the traditional DCF model with an unconventional adjustment. Dr. Gaske's model looks like this:

$$\mathbf{K = D_1(1+.625) / P_0 (1\text{-}f) + g}$$

---

[31] Morin, Roger Dr., New Regulatory Finance (2006), p. 283

[32] Morin, Roger Dr., New Regulatory Finance (2006), p. 344

Manipulating the DCF model simply to increase the dividend yield goes beyond the analysis judgment parameters. There is no academic literature cited in the testimony that supports such an adjustment to the DCF calculation. The result is an overestimated cost of capital.

Second Stage Growth Model

In reviewing the literature, the closest I came to finding a rational basis of support for Dr. Gaske's second stage growth rate used in the NCDCF model was the blended growth approach mentioned below.

> *"One way to account for the two stages growth is to modify the single-stage DCF model by specifying the growth rate as a weighted average of short-term and long-term rates. The blended growth rate is calculated as a weighted average giving two-thirds weight to the analysts' five year projected growth (Zacks, IBES, etc.) and one-third to historical long-term growth of the economy as a whole and/or the long-range projections of growth in Gross Domestic Product (GDP) projected for the very long term."*[33]
> *– Dr. Roger Morin*

For reasons unknown to the OCA, Dr. Gaske did not seem to follow the formula all the way through.

Dr. Gaske starts off using the blended growth approach by using the analysts' five year projected growth rate and giving it the two-thirds weight. The deviation starts when he used the 2012-2014 retention growth rate of the proxy group instead of the historical long-term growth of the economy as a whole and/or GDP. In Morin's book he gives an example that uses the average GDP over 75 years. The long-term average reference for the blended growth approach is for a substantially longer duration than that used by Dr. Gaske.

Dr. Gaske may be creatively trying to mitigate a constant retention ratio the traditional DCF model assumes. By including the retention growth rate as part of the blended growth rate the assumption in the first calculation seems to be mitigated; however there is no academic work cited that indicated this adjustment is an accepted practice. Dr. Gaske

[33] Morin, Roger Dr., New Regulatory Finance (2006), p. 309

does not cite the academic practices or empirical research that would make using the retention growth rate in this manner an acceptable approach.

The model Dr. Gaske uses is:

$$K = D_1(1+.625) / P_0 (1-f) + g$$

Where g is a weighted average of analysts' growth projections on earnings with a two thirds weight multiplied by retention growth with a one third weight.

Dr. Gaske's analysis was not clear in the academic practices that allow the adjustments to the DCF model for both his DCF calculations. The purpose of using multiple calculations is to minimize the assumptions and weaknesses of any given model using accepted practices and establish a range of reasonableness for which informed judgment can be applied. Dr. Gaske's testimony is not clear in how the models he selected contributed to minimizing the weaknesses of the inherent assumptions and maximized the strengths of the chosen models.

Q. PLEASE EXPLAIN YOUR DISAGREEMENTS WITH THE RISK PREMIUM ANALYSIS.

A. My disagreement with the use of the Risk Premium analysis is that the results of the Risk Premium analysis in no way legitimize or produce support for the results derived from the DCF models. Common knowledge dictates that regulated utility companies, by virtue of their status as regulated monopolies, have a much lower risk profile than companies that operate in competitive markets.

Dr. Gaske's testimony gives no detail into how closely the utility industry outcome follows the results indicated in his Risk premium analysis. Dr. Gaske comes to the conclusion that since the DCF calculations produced results that are less than half of the results of the Risk Premium outcome that this somehow legitimizes the results from the DCF models. Again there is no academic citing that allows a reasonable person to arrive at the same deductive reasoning included in the testimony. The OCA sees no supporting evidence regarding the reasonableness of the DCF outcome to reach the conclusion stated in the testimony regarding Risk Premium.

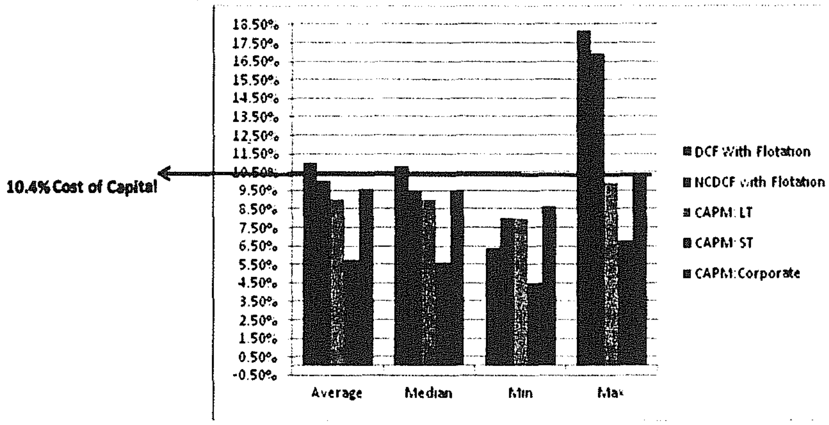
The OCA gives little weight in the results for the Risk Premium supporting any calculation related to the DCF analysis because of the fact that we are dealing with a regulated industry in this preceding. Regulated entities are not represented in Dr. Gaske's calculation. An aggregate Risk Premium calculation such as that performed by Dr. Gaske reveals the results of the market, of which regulated utilities are a small minority, and includes all industries regardless of risk. Regulated utilities have been historically proven to be much less risky than the market thus the relevance of Dr. Gaske's Risk Premium analysis is minimal.

Q. HOW SHOULD THE COMMISSION WEIGHT THESE OBSERVATIONS IN CONSIDERING YOUR TESTIMONY IN THIS PROCEEDING?

A. The OCA attempted to use all relevant evidence known and available, in order to minimize judgmental, measurement, and conceptual error. The Cost of Common Equity was determined using 3 calculations and informed judgment. The summary of the results is indicated in the tables below:

OCA Calculations

DCF With Flotation	10.93%	10.84%	6.36%	18.17%
NCDCF with Flotation	10.01%	9.45%	7.97%	16.88%
CAPM: LT	9.05%	8.94%	7.96%	9.91%
CAPM: ST	5.75%	5.61%	4.43%	6.80%
CAPM: Corporate	9.58%	9.48%	8.66%	10.31%



I selected a cost of capital of 10.40% by considering the macroeconomic conditions and risk presently facing the company. I determined the present financial and business risks to be average but with the uncertainly of the national financial markets I selected a cost of capital that was at the higher end of the average since there are still important economic factors that are not yet stabilized, which adds to the macroeconomic risk, although they seem to be moving in a positive direction.

I then reviewed the capital structure and the result was the following table:

Source	Balance	Ratio	Cost	Required Return
Pro Forma				
LT Debt	$280,505,118	44.96%	6.79%	3.05%
ST Debt	$17,287,362	2.77%	3.77%	0.10%
Preferred Stock	$15,600,000	2.50%	4.59%	0.11%
Common Equity	$310,520,102	49.77%	10.40%	5.18%
Total	$623,912,582	100.00%		8.45%

Q. DOES THAT CONCLUDE YOUR TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A GENERAL RATE INCREASE IN ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING OF $70,918,825 PER ANNUM OR AN AVERAGE OVERALL INCREASE OF 13.7 PERCENT	)	DOCKET NO. 20000-352-ER-09 RECORD NO. 12310

AFFIDAVIT, OATH AND VERIFICATION

Kimber McCrea Wichmann (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is a Rate Analyst with the Wyoming Office of Consumer Advocate which is party intervenor in this matter pursuant to its Notice of Intervention filed on August 25, 2009.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification

Affiant hereby verifies that, based upon Affiant's knowledge, all statements and information contained within the testimony and all of its attached schedules are true and complete and constitute the recommendations of the Affiant in her official capacity as a Rate Analyst with the Wyoming Office of Consumer Advocate.

Further Affiant Sayeth Not.

DATED this 19th day of January, 2010.

Kimber McCrea Wichmann

Kimber McCrea Wichmann, Rate Analyst
Wyoming Office of Consumer Advocate
2515 Warren Avenue, Suite 304
Cheyenne, WY 82002
(307) 777-5705

DONNA T. CROCK NOTARY PUBLIC
COUNTY OF LARAMIE STATE OF WYOMING
MY COMMISSION EXPIRES AUG. 25, 2010

STATE OF WYOMING)

)SS:

COUNTY OF LARAMIE)

The foregoing was acknowledged before me by Kimber McCrea Wichmann on this 19th day of January, 2010. Witness my hand and official seal.

Donna T. Crock
Notary Public

My Commission Expires: August 25, 2010

Universe of Electric Companies From Value Line

Name	TICKER	Online Moody's	S&P
DU RESOURCES GROUP	MDU	Baa1	BBB+
LLEGHENY ENERGY	AYE	Ba1	BBB-
ALLETE	ALE	Baa1	BBB+
ALLIANT ENERGY	LNT	Baa1	BBB+
AMEREN CORPORATION	AEE	Baa3	BBB-
AMERICAN ELEC PWR	AEP	Baa2	BBB
AVISTA	AVA	Baa3	BBB-
BLACK HILLS CORP	BKH	Baa3	BBB-
CENTERPOINT ENERGY	CNP	Ba1	BBB
CENTRAL VERMONT P.S.	CV	Ba2	BB+
CH ENERGY Central Hudson Gas & Electric Corp	CHG	A3	A
CLECO CORPORATION	CNL	(P)Baa3	BBB
CMS ENERGY CORP	CMS	Ba1	BBB-
CONSOLIDATED EDISON	ED	Baa1	A-
CONSTELLATION ENERGY	CEG	Baa3	BBB-
DOMINION RES	D		A-
DPL INC	DPL	Baa1	A-
DTE ENERGY CO	DTE	Baa2	BBB
DUKE ENERGY	DUK	Baa2	A-
EDISON INTERNAT	EIX	Baa2	BBB-
EL PASO ELECTRIC	EE	Baa2	BBB
EMPIRE DISTRICT	EDE	Baa2	BBB-
ENTERGY CORP	ETR	Baa3	BBB
EXELON CORP	EXC	Baa1	BBB
FIRSTENERGY	FE	Baa3	BBB
. GROUP, INC	FPL	A2	A
REAT PLAINS ENERGY	GXP	Baa3	BBB
HAWAIIAN ELECTRIC	HE	Baa1	BBB
IDACORP, INC	IDA	Baa2	BBB
INTEGRYS ENERGY	TEG	Baa1	BBB+
ITC HOLDINGS CORP	ITC	Baa3	BBB
MGE ENERGY INC (Madison Gas & Electric)	MGEE	Aa3	AA-
NORTHEAST UTLITIES	NU	Baa2	BBB
NORTHWESTERN CORPORATION	NWEC	A3	BBB
NSTAR	NST	A2	A+
NV ENERGY	NVE	Ba1	BB
OGE ENERGY CORP	OGE	Baa1	BBB+
OTTER TAIL CORP	OTTR	A3	BBB-
PEPCO HOLDINGS	POM	Baa3	BBB
PG&E CORP	PCG	Baa1	BBB+
PINNACLE WEST	PNW	Baa3	BBB-
PNM RESOURCES	PNM	Ba2	BB-
PORTLAND GENERAL ELECTRIC INC	POR	Baa2	BBB+
PPL CORPORATION	PPL	Baa2	BBB
PROGRESS ENERGY	PGN	Baa2	BBB+
PUBLIC SERVICE ENTERPRISE GROUP	PEG	(P)Baa2	BBB
SCANA CORP	SCG	Baa2	BBB+
SEMPRA ENERGY SRE	SRE	Baa1	BBB+
SOUTHERN CO	SO	A3	A
TECO ENERGY, INC	TE	Baa3	BBB
. HOLDINGS	UIL	Baa3	
NISOURCE ENERGY	UNS	Ba1	
VECTREN CORP	VVC		A-
WESTAR ENERGY	WR	Baa3	BBB-
WISCONSIN ENERGY	WEC	A3	BBB+
XCEL ENERGY	XEL	Baa1	BBB+

Electric Companies Regulated Electric Revenues of 70% and Higher

	Name	TICKER	Online Moody's	S&P	% REG ELEC REV
1	ALLETE	ALE	Baa1	BBB+	90
2	AMEREN CORPORATION	AEE	Baa3	BBB-	83
3	AMERICAN ELEC PWR	AEP	Baa2	BBB	95
4	CLECO CORPORATION	CNL	(P)Baa3	BBB	96
5	DPL INC	DPL	Baa1	A-	100
6	DUKE ENERGY	DUK	Baa2	A-	76
7	EDISON INTERNAT	EIX	Baa2	BBB-	80
8	EL PASO ELECTRIC	EE	Baa2	BBB	97
9	EMPIRE DISTRICT	EDE	Baa2	BBB-	86
10	ENTERGY CORP	ETR	Baa3	BBB	77
11	EXELON CORP	EXC	Baa1	BBB	81
12	FIRSTENERGY	FE	Baa3	BBB	88
13	GREAT PLAINS ENERGY	GXP	Baa3	BBB	100
14	HAWAIIAN ELECTRIC	HE	Baa1	BBB	98
15	IDACORP, INC	IDA	Baa2	BBB	100
16	NORTHEAST UTLITIES	NU	Baa2	BBB	81
17	PG&E CORP	PCG	Baa1	BBB+	76
18	PINNACLE WEST	PNW	Baa3	BBB-	97
19	PORTLAND GENERAL ELECTRIC INC	POR	Baa2	BBB+	98
20	PROGRESS ENERGY	PGN	Baa2	BBB+	100
21	UIL HOLDINGS	UIL	Baa3		100
22	WESTAR ENERGY	WR	Baa3	BBB-	71
23	XCEL ENERGY	XEL	Baa1	BBB+	80

Proxy Group

	Name	BUSINESS	TICKER	Online Moody's	S&P	% REG ELEC REV
1	ALLETE	GAS & ELECTRIC	ALE	Baa1	BBB+	90
2	AMEREN CORPORATION	GAS & ELECTRIC	AEE	Baa3	BBB-	83
3	AMERICAN ELEC PWR	ELECTRIC	AEP	Baa2	BBB	95
4	CLECO CORPORATION	ELECTRIC	CNL	(P)Baa3	BBB	96
5	DPL INC	ELECTRIC	DPL	Baa1	A-	100
6	DUKE ENERGY	GAS & ELECTRIC	DUK	Baa2	A-	76
7	EDISON INTERNAT	ELECTRIC	EIX	Baa2	BBB-	80
8	EMPIRE DISTRICT	GAS & ELECTRIC	EDE	Baa2	BBB-	86
9	ENTERGY CORP	GAS & ELECTRIC	ETR	Baa3	BBB	77
10	EXELON CORP	GAS & ELECTRIC	EXC	Baa1	BBB	81
11	FIRSTENERGY	ELECTRIC	FE	Baa3	BBB	88
12	GREAT PLAINS ENERGY	ELECTRIC	GXP	Baa3	BBB	100
13	HAWAIIAN ELECTRIC	ELECTRIC	HE	Baa1	BBB	98
14	IDACORP, INC	ELECTRIC	IDA	Baa2	BBB	100
15	NORTHEAST UTLITIES	GAS & ELECTRIC	NU	Baa2	BBB	81
16	PG&E CORP	GAS & ELECTRIC	PCG	Baa1	BBB+	76
17	PINNACLE WEST	ELECTRIC	PNW	Baa3	BBB-	97
18	PORTLAND GENERAL ELECTRIC INC	ELECTRIC	POR	Baa2	BBB+	98
19	PROGRESS ENERGY	ELECTRIC	PGN	Baa2	BBB+	100
20	UIL HOLDINGS	ELECTRIC	UIL	Baa3		100
21	WESTAR ENERGY	ELECTRIC	WR	Baa3	BBB-	71
22	XCEL ENERGY	GAS & ELECTRIC	XEL	Baa1	BBB+	80

DCF: Establi[illegible] Dividend and Growth Analysis

E[illegible]t KMW4

lame	TICKER	Value Line projected 2010 Dividend Per Share	Stock Price WSJ 11/12/09	Calculated Dividend Yield	Value Line Dividend Yield	Value Line Earnings Growth	Value Line Book Growth	Yahoo! Financial Earnings Growth	Zacks Earnings Growth	Average Earnings growth (EG)	Dividend only DCF using earnings growth w/ flotation
LLETE	ALE	1.80	32.68	0.0550796	5.4%	-1.0%	3.0%	6.0%	4.0%	3.0%	8.7%
MEREN CORPORATION	AEE	1.54	25.4	0.0606299	5.9%	1.0%	2.5%	3.0%	4.0%	2.7%	8.9%
MERICAN ELEC PWR	AEP	1.66	31.39	0.0528831	5.2%	3.0%	5.0%	3.0%	3.3%	3.1%	8.6%
LECO CORPORATION	CNL	1.00	25.03	0.0399521	3.9%	9.5%	4.5%	12.5%	9.0%	10.3%	14.5%
PL INC	DPL	1.18	27.22	0.0433505	4.5%	8.5%	5.0%	9.4%	6.2%	8.0%	12.5%
UKE ENERGY	DUK	0.98	16.01	0.0612117	6.4%	5.0%	-0.5%	3.2%	4.7%	4.3%	10.6%
DISON INTERNAT	EIX	1.28	33.24	0.0385078	3.9%	3.5%	6.5%	3.0%	5.0%	3.8%	7.8%
MPIRE DISTRICT	EDE	1.28	18.04	0.0709534	7.1%	6.0%	2.0%	6.0%	0.0%	4.0%	11.4%
NTERGY CORP	ETR	3.00	76.79	0.0390676	3.8%	6.0%	6.5%	8.4%	6.0%	6.8%	10.8%
XELON CORP	EXC	2.10	46.07	0.0455828	4.3%	6.0%	10.5%	4.3%	2.0%	4.1%	8.8%
IRSTENERGY	FE	2.20	41.64	0.0528338	5.0%	4.0%	4.5%	4.5%	7.0%	5.2%	10.6%
REAT PLAINS ENERGY	GXP	0.83	17.7	0.0468927	4.6%	0.5%	3.0%	2.0%	2.0%	1.5%	6.4%
AWAIIAN ELECTRIC	HE	1.24	19.05	0.0650919	4.5%	7.0%	2.0%	3.0%	3.0%	4.3%	11.1%
ACORP, INC	IDA	1.20	28.86	0.04158	4.4%	4.5%	5.0%	5.0%	5.0%	4.8%	9.1%
C HOLDINGS CORP	ITC	1.31	45.16	0.029008	2.8%	12.5%	9.5%	17.0%	16.0%	15.2%	18.2%
ORTHEAST UTLITIES	NU	1.00	23.4	0.042735	4.2%	8.0%	5.0%	9.3%	8.5%	8.6%	13.0%
G&E CORP	PCG	1.80	41.6	0.0432692	4.4%	6.5%	7.0%	7.0%	7.5%	7.0%	11.5%
INNACLE WEST	PNW	2.10	33.1	0.0634441	6.5%	3.0%	1.0%	8.0%	8.0%	6.3%	12.9%
ORTLAND GENERAL ELECTRIC INC	POR	1.05	19.03	0.055176	5.5%	3.5%	2.5%	6.8%	7.0%	5.8%	11.5%
ROGRESS ENERGY	PGN	2.50	37.96	0.0658588	6.4%	6.0%	2.0%	4.4%	4.3%	4.9%	11.7%
IL HOLDINGS	UIL	1.73	26.48	0.0653323	6.8%	3.0%	2.5%	4.5%	4.0%	3.8%	10.6%
VESTAR ENERGY	WR	1.24	19.77	0.0627213	5.9%	4.5%	6.0%	2.5%	4.5%	3.8%	10.3%
CEL ENERGY	XEL	1.00	19.43	0.0514668	5.0%	6.5%	4.5%	7.4%	5.5%	6.5%	11.8%
VERAGE		**1.52**	**30.65**	**5.19%**	**5.06%**	**5.09%**	**4.33%**	**6.09%**	**5.50%**	**5.56%**	**10.93%**
IEDIAN		**1.28**	**27.22**	**5.28%**	**5.00%**	**5.00%**	**4.50%**	**5.00%**	**5.00%**	**4.83%**	**10.84%**
IINIMUM		0.83	16.01	2.90%	2.80%	-1.00%	-0.50%	2.00%	0.00%	1.50%	6.36%
IAXIMUM		3.00	76.79	7.10%	7.10%	12.50%	10.50%	17.00%	16.00%	15.17%	18.17%

Ex[illegible] KMW5

Non Constant DCF

		Earnings per share					Dividends per share				
ame	Vale Line 2009 Earnings per Share	Value Line EPS 2010	Imputed EPS 2011	Imputed EPS 2012	Imputed EPS 2013	Value Line EPS 2014	Value Line 2009 Dividend Yield	Value Line DY 2010	Imputed DY 2011	Imputed DY 2012	Imputed DY 2013
LLETE	1.95	2.30	2.45	2.55	2.62	2.75	1.76	1.80	1.84	1.87	1.88
MEREN CORPORATION	2.85	2.55	2.70	2.80	2.87	3.00	1.54	1.54	1.59	1.63	1.65
MERICAN ELEC PWR	2.90	3.00	3.17	3.28	3.35	3.50	1.64	1.66	1.74	1.79	1.83
LECO CORPORATION	1.70	2.00	2.17	2.28	2.35	2.50	0.90	1.00	1.20	1.33	1.42
PL INC	2.10	2.45	2.53	2.59	2.63	2.70	1.14	1.18	1.22	1.25	1.26
UKE ENERGY	1.10	1.20	1.27	1.31	1.34	1.40	0.94	0.98	1.02	1.05	1.06
DISON INTERNAT	2.85	3.10	3.48	3.74	3.91	4.25	1.25	1.28	1.35	1.40	1.43
MPIRE DISTRICT	1.50	1.55	1.62	1.66	1.69	1.75	1.28	1.28	1.30	1.32	1.33
NTERGY CORP	3.00	7.00	7.33	7.56	7.70	8.00	3.00	3.00	3.20	3.33	3.42
KELON CORP	4.20	4.20	4.63	4.92	5.11	5.50	2.10	2.10	2.20	2.27	2.31
RSTENERGY	3.65	3.50	4.08	4.47	4.73	5.25	2.20	2.20	2.35	2.45	2.52
REAT PLAINS ENERGY	1.20	1.40	1.47	1.51	1.54	1.60	0.83	0.83	0.92	0.98	1.02
AWAIIAN ELECTRIC	1.15	1.50	1.58	1.64	1.68	1.75	1.24	1.24	1.24	1.24	1.24
ACORP, INC	2.40	2.50	2.58	2.64	2.68	2.75	1.20	1.20	1.27	1.31	1.34
C HOLDINGS CORP	2.40	2.50	2.75	2.92	3.03	3.25	1.25	1.31	1.37	1.42	1.44
ORTHEAST UTLITIES	1.85	1.95	2.05	2.12	2.16	2.25	0.95	1.00	1.05	1.08	1.11
G&E CORP	3.20	3.40	3.68	3.87	4.00	4.25	1.68	1.80	1.93	2.02	2.08
NNACLE WEST	2.30	2.80	2.95	3.05	3.12	3.25	2.10	2.10	2.13	2.16	2.17
ORTLAND GENERAL ELECTRIC INC	1.35	1.75	1.83	1.89	1.93	2.00	1.01	1.05	1.10	1.13	1.16
ROGRESS ENERGY	3.10	3.25	3.37	3.44	3.50	3.60	2.48	2.50	2.52	2.53	2.54
L HOLDINGS	1.90	2.00	2.08	2.14	2.18	2.25	1.73	1.73	1.73	1.73	1.73
ESTAR ENERGY	1.70	1.85	1.97	2.04	2.10	2.20	1.19	1.24	1.29	1.33	1.35
CEL ENERGY	1.50	1.60	1.73	1.82	1.88	2.00	0.97	1.00	1.03	1.06	1.07
AVERAGE	2.25	2.58	2.76	2.88	2.96	3.12	1.49	1.52	1.59	1.64	1.67
MEDIAN	2.10	2.45	2.53	2.59	2.63	2.75	1.25	1.28	1.35	1.40	1.43
MINIMUM	1.10	1.20	1.27	1.31	1.34	1.40	0.83	0.83	0.92	0.98	1.02
MAXIMUM	4.20	7.00	7.33	7.56	7.70	8.00	3.00	3.00	3.20	3.33	3.42

	Retention Ratio (Calculated)										
alue Line Y 2014	Retention Ratio 2009	Retention Ratio 2010	Retention Ratio 2011	Retention Ratio 2012	Retention Ratio 2013	Retention Ratio 2014	Value Line ROE 2012-14	Sustainable Growth Rate	Stock Price WSJ 11/12/09		Non-Constant Growth DCF
1.92	9.74%	21.74%	24.90%	26.80%	27.98%	30.18%	9.00%	2.72%	32.68	$32.68	8.02%
1.70	45.96%	39.61%	40.99%	41.83%	42.35%	43.33%	8.00%	3.47%	25.40	$25.40	9.34%
1.90	43.45%	44.67%	45.05%	45.29%	45.44%	45.71%	11.00%	5.03%	31.39	$31.39	10.04%
1.60	47.06%	50.00%	44.62%	41.46%	39.53%	36.00%	11.50%	4.14%	25.03	$25.03	9.43%
1.30	45.71%	51.84%	51.84%	51.85%	51.85%	51.85%	26.50%	13.74%	27.22	$27.22	16.68%
1.10	14.55%	18.33%	19.47%	20.17%	20.61%	21.43%	8.00%	1.71%	16.01	$16.01	8.10%
1.50	56.14%	58.71%	61.15%	62.50%	63.30%	64.71%	11.00%	7.12%	33.24	$33.24	10.58%
1.35	14.67%	17.42%	19.38%	20.60%	21.38%	22.86%	10.50%	2.40%	18.04	$18.04	9.25%
3.60	0.00%	57.14%	56.36%	55.88%	55.58%	55.00%	14.00%	7.70%	76.79	$76.78	11.22%
2.40	50.00%	50.00%	52.52%	53.95%	54.82%	56.36%	20.00%	11.27%	46.07	$46.07	14.76%
2.65	39.73%	37.14%	42.45%	45.22%	46.81%	49.52%	14.50%	7.18%	41.64	$41.64	12.06%
1.10	30.83%	40.71%	37.27%	35.15%	33.80%	31.25%	7.00%	2.19%	17.70	$17.70	7.77%
1.24	-7.83%	17.33%	21.68%	24.34%	26.01%	29.14%	10.00%	2.91%	19.05	$19.05	8.81%
1.40	50.00%	52.00%	50.97%	50.32%	49.90%	49.09%	7.50%	3.68%	28.86	$28.86	7.88%
1.50	47.92%	47.60%	50.06%	51.47%	52.32%	53.85%	13.00%	7.00%	45.16	$45.16	9.56%
1.15	48.65%	48.72%	48.78%	48.82%	48.84%	48.89%	8.50%	4.16%	23.40	$23.40	8.34%
2.20	47.50%	47.06%	47.51%	47.78%	47.94%	48.24%	12.00%	5.79%	41.60	$41.60	10.03%
2.20	8.70%	25.00%	27.68%	29.33%	30.36%	32.31%	9.00%	2.91%	33.10	$33.10	8.89%
1.20	25.19%	40.00%	40.00%	40.00%	40.00%	40.00%	8.50%	3.40%	19.03	$19.03	8.92%
2.56	20.00%	23.08%	25.15%	26.45%	27.29%	28.89%	9.50%	2.74%	37.96	$37.96	8.87%
1.73	8.95%	13.50%	16.96%	19.12%	20.49%	23.11%	10.50%	2.43%	26.48	$26.48	8.44%
1.40	30.00%	32.97%	34.24%	35.00%	35.48%	36.36%	8.00%	2.91%	19.77	$19.77	9.22%
1.10	35.33%	37.50%	40.38%	42.07%	43.11%	45.00%	10.50%	4.73%	19.43	$19.43	9.48%
1.73	30.97%	37.92%	39.11%	39.80%	40.22%	41.00%	11.22%	4.84%	30.65		9.81%
1.50	35.33%	40.00%	40.99%	41.83%	42.35%	43.33%	10.50%	3.68%	27.22		9.25%
1.10	-7.83%	13.50%	16.96%	19.12%	20.49%	21.43%	7.00%	1.71%	16.01		7.77%
3.60	56.14%	58.71%	61.15%	62.50%	63.30%	64.71%	26.50%	13.74%	76.79		16.68%

Name	Value Line projected Dividend Yield	Stock Price WSJ 11/12/09	Calculated Dividend Yield	Value Line Dividend Yield	Value Line Earnings Growth	Value Line Book Growth	Yahoo! Financial Earnings Growth	Zacks Earnings Growth	Average Earnings growth (EG)
ALLETE	1.76	32.68	0.053855569	5.4%	-1.0%	3.0%	6.0%	4.0%	3.00%
AMEREN CORPORATION	1.54	25.4	0.060629921	5.9%	1.0%	2.5%	3.0%	4.0%	2.67%
AMERICAN ELEC PWR	1.64	31.39	0.052245938	5.2%	3.0%	5.0%	3.0%	3.3%	3.10%
CLECO CORPORATION	0.90	25.03	0.035956852	3.9%	9.5%	4.5%	12.5%	9.0%	10.33%
DPL INC	1.14	27.22	0.04188097	4.5%	8.5%	5.0%	9.4%	6.2%	8.04%
DUKE ENERGY	0.94	16.01	0.058713304	6.4%	5.0%	-0.5%	3.2%	4.7%	4.30%
EDISON INTERNAT	1.25	33.24	0.037605295	3.9%	3.5%	6.5%	3.0%	5.0%	3.83%
EMPIRE DISTRICT	1.28	18.04	0.070953437	7.1%	6.0%	2.0%	6.0%	0.0%	4.00%
ENTERGY CORP	3.00	76.79	0.039067587	3.8%	6.0%	6.5%	8.4%	6.0%	6.79%
EXELON CORP	2.10	46.07	0.045582809	4.3%	6.0%	10.5%	4.3%	2.0%	4.11%
FIRSTENERGY	2.20	41.64	0.052833814	5.0%	4.0%	4.5%	4.5%	7.0%	5.17%
GREAT PLAINS ENERGY	0.83	17.7	0.046892655	4.6%	0.5%	3.0%	2.0%	2.0%	1.50%
HAWAIIAN ELECTRIC	1.24	19.05	0.065091864	4.5%	7.0%	2.0%	3.0%	3.0%	4.33%
IDACORP, INC	1.20	28.86	0.041580042	4.4%	4.5%	5.0%	5.0%	5.0%	4.83%
ITC HOLDINGS CORP	1.25	45.16	0.027679362	2.8%	12.5%	9.5%	17.0%	16.0%	15.17%
NORTHEAST UTLITIES	0.95	23.4	0.040598291	4.2%	8.0%	5.0%	9.3%	8.5%	8.58%
PG&E CORP	1.68	41.6	0.040384615	4.4%	6.5%	7.0%	7.0%	7.5%	7.00%
PINNACLE WEST	2.10	33.1	0.063444109	6.5%	3.0%	1.0%	8.0%	8.0%	6.33%
PORTLAND GENERAL ELECTRIC INC	1.01	19.03	0.053074094	5.5%	3.5%	2.5%	6.8%	7.0%	5.75%
PROGRESS ENERGY	2.48	37.96	0.065331928	6.4%	6.0%	2.0%	4.4%	4.3%	4.90%
UIL HOLDINGS	1.73	26.48	0.065332326	6.8%	3.0%	2.5%	4.5%	4.0%	3.82%
WESTAR ENERGY	1.19	19.77	0.06019221	5.9%	4.5%	6.0%	2.5%	4.5%	3.83%
XCEL ENERGY	0.97	19.43	0.0499228	5.0%	6.5%	4.5%	7.4%	5.5%	6.47%
AVERAGE	1.49	30.65	0.05	5.06%	5.09%	4.33%	6.09%	5.50%	5.56%
MEDIAN	1.25	27.22	0.05	5.00%	5.00%	4.50%	5.00%	5.00%	4.83%
MINIMUM	0.83	16.01	0.03	2.80%	-1.00%	-0.50%	2.00%	0.00%	1.50%
MAXIMUM	3.00	76.79	0.07	7.10%	12.50%	10.50%	17.00%	16.00%	15.17%

Dividend only DCF using only earnings for growth	Dividend only DCF using only earnings for growth with flotation	Value Line Beta	ST Risk Free Rate (US 1 month Treasury Bill 12/07/09 WSJ)	Ibbotsons ST Equity Risk Premium	LT Risk Free Rate (US 30-year Bond 12/07/09 WSJ)	Ibbotsons LT Equity Risk Premium	Corp Risk Free Rate (Mergent Bond Record Corporate Bond Yield Averages AV. Corp Nov 2009 p.11)	Corp Equity Risk Premium	Long Term CAPM	Short Term CAPM	Corporate CAPM
8.5%	8.7%	0.7	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
8.9%	9.1%	0.8	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.59%	6.40%	10.03%
8.5%	8.7%	0.7	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
14.3%	14.4%	0.65	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.61%	5.22%	9.21%
12.6%	12.7%	0.6	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.29%	4.82%	8.93%
10.4%	10.6%	0.65	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.61%	5.22%	9.21%
7.7%	7.9%	0.8	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.59%	6.40%	10.03%
11.4%	11.6%	0.75	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.26%	6.01%	9.76%
11.0%	11.1%	0.7	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
8.9%	9.0%	0.85	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.91%	6.80%	10.31%
10.7%	10.9%	0.8	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.59%	6.40%	10.03%
6.3%	6.4%	0.75	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.26%	6.01%	9.76%
11.1%	11.4%	0.7	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
9.2%	9.4%	0.7	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
18.4%	18.5%	0.85	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.91%	6.80%	10.31%
13.0%	13.2%	0.7	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
11.3%	11.5%	0.55	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	7.96%	4.43%	8.66%
13.1%	13.3%	0.75	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.26%	6.01%	9.76%
11.4%	11.6%	0.75	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.26%	6.01%	9.76%
11.8%	12.0%	0.65	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.61%	5.22%	9.21%
10.6%	10.9%	0.7	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
10.1%	10.3%	0.75	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	9.26%	6.01%	9.76%
11.8%	12.0%	0.65	0.08%	7.90%	4.39%	6.50%	5.63%	5.50%	8.61%	5.22%	9.21%
10.9%	11.1%	0.7	0.1%	7.9%	4.39%	6.50%	5.63%	5.50%	**9.05%**	**5.75%**	**9.58%**
11.0%	11.1%	0.7	0.1%	7.9%	4.39%	6.50%	5.63%	5.50%	8.94%	5.61%	9.48%
6.3%	6.4%	0.6	0.1%	7.9%	4.39%	6.50%	5.63%	5.50%	7.96%	4.43%	8.66%
18.4%	18.5%	0.9	0.1%	7.9%	4.39%	6.50%	5.63%	5.50%	9.91%	6.80%	10.31%

?roxy Group Debt to Equity Breakout

?ame	TICKER	% LT Debt	% Preferred	% Common Equity
?LLETE	ALE	44.50%	0.00%	55.50%
?MEREN CORPORATION	AEE	47.50%	1.50%	51.00%
?MERICAN ELEC PWR	AEP	53.50%	0.00%	46.50%
?LECO CORPORATION	CNL	53.00%	0.00%	47.00%
?PL INC	DPL	56.50%	0.00%	43.50%
?UKE ENERGY	DUK	40.50%	0.00%	59.50%
?DISON INTERNAT	EIX	51.50%	4.50%	44.00%
?L PASO ELECTRIC	EE	51.50%	0.00%	48.50%
?MPIRE DISTRICT	EDE	54.00%	0.00%	46.00%
?NTERGY CORP	ETR	58.00%	1.50%	40.50%
?XELON CORP	EXC	48.00%	0.50%	51.50%
?IRSTENERGY	FE	53.00%	0.00%	47.00%
?REAT PLAINS ENERGY	GXP	53.00%	1.00%	46.00%
?AWAIIAN ELECTRIC	HE	49.00%	1.00%	50.00%
?ACORP, INC	IDA	46.00%	0.00%	54.00%
?C HOLDINGS CORP	ITC	69.50%	0.00%	30.50%
?ORTHEAST UTLITIES	NU	59.00%	1.00%	40.00%
?G&E CORP	PCG	50.50%	1.00%	48.50%
?INNACLE WEST	PNW	51.50%	0.00%	48.50%
?ORTLAND GENERAL ELECTRIC INC	POR	47.50%	0.00%	52.50%
?ROGRESS ENERGY	PGN	55.00%	0.00%	45.00%
?IL HOLDINGS	UIL	52.00%	0.00%	48.00%
?ESTAR ENERGY	WR	52.00%	0.50%	47.50%
?CEL ENERGY	XEL	52.00%	0.50%	47.50%

AVERAGE		52.02%	0.54%	47.44%
MEDIAN		52.00%	0.00%	47.50%
MINIMUM		40.50%	0.00%	30.50%
MAXIMUM		69.50%	4.50%	59.50%

WEIGHTED AVERAGE COST OF CAPITAL

OCA's Capital Structure

	Balance	Ratio	Cost	Required Return
Per Books				
LT Debt	$236,008,867	41.14%	6.87%	2.83%
ST Debt	$53,997,678	9.41%	3.56%	0.33%
Preferred Stock	$15,700,000	2.74%	4.60%	0.13%
Common Equity	$267,911,317	46.71%	10.40%	4.86%
Total	$573,617,862	100.00%		8.14%

Source	Balance	Ratio	Cost	Required Return
Pro Forma				
LT Debt	$280,505,118	44.96%	6.79%	3.05%
ST Debt	$17,287,362	2.77%	3.77%	0.10%
Preferred Stock	$15,600,000	2.50%	4.59%	0.11%
Common Equity	$310,520,102	49.77%	10.40%	5.18%
Total	$623,912,582	100.00%		8.45%

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC-045

Regarding: Postretirement medical benefits for employees under age 65
Witness: Jones

a. **Please explain MDU's current plans for changes to its postretirement medical benefits for employees under age 65.**

b. **Identify all expenses included in this case that pertain to postretirement medical benefits and, if applicable, provide an adjustment which reflects a reduction in expenses related to post test-year reduction in postretirement medical benefits.**

Response:

a. Montana-Dakota's post retirement benefits are as follows:
   - Employees hired prior to January 1, 2010 who attained age 55 and 10 continuous years of service by December 31, 2010 have the choice between Montana-Dakota's retirement option(s) prior to January 1, 2010 or the new Retirement Reimbursement Account
   - Employees hired prior to January 1, 2010 who had not attained age 55 and 10 continuous years of service by December 31, 2010 are eligible for the Retirement Reimbursement Account
   - Employees hired January 1, 2010 or later, are not eligible for any type of retiree medical benefit from the company
   - Employees that transferred to Montana-Dakota from within the corporation are eligible for the Retirement Reimbursement Account, as long as they were eligible for retiree medical at their former company
   - Employees that transferred to Montana-Dakota on December 21, 2009 as a result of the Utility Integration, and who meet the 55/10 requirement, were grandfathered under the plan(s) of the company from which they transferred.

b. Please see Rule 38.5.157, Statement G, page 5 of 15 for the postretirement expenses included in the case and Attachment A for the updated adjustment to postretirement expense to incorporate the change in postretirement medical expenses discussed by Ms. Jones in her testimony on page 6, lines 13-18. Page 1 is the updated Statement G, page 5 and page 2 is the updated Statement Workpapers, Statement G, page G-44.

Updated to reflect annualized post-retirement.

MONTANA-DAKOTA UTILITIES CO.
BENEFITS EXPENSE
GAS UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2011
ADJUSTMENT NO. 7

	Per Books			Pro Forma
	Gas Utility	Montana	Pro Forma 1/	Adjustment
Medical/Dental	$2,117,808	$623,431	$628,980	$5,549
Pension expense	514,314	155,387	(64,455)	(219,842)
Post-retirement	453,151	152,499	339,539	187,040
401-K	2,145,671	605,091	689,804	84,713
Workers compensation	114,735	50,015	52,383	2,368
Supplemental Insurance	617,368	179,996	0	(179,996)
Total	$5,963,047	$1,766,419	$1,646,251	($120,168)

1/ Reflects an increase of 0.89% to medical and dental, a decrease of 141.48% to Pension expense an increase of 122.65% to Post-retirement expense, an increase of 14% to 401-K expense. Workers Compensation expense is based on the ratio of worker's compensation to pro forma labor expense and Supplemental Insurance was eliminated from benefits expense.

MONTANA-DAKOTA UTILITIES CO.
BENEFITS EXPENSE - UTILITY
TWELVE MONTHS ENDING DECEMBER 31, 2011

Medical/Dental (5194)	Per Books	2012 Plan	% Change
Electric	$2,603,462	$2,589,656	-0.53%
Gas	2,398,720	2,456,930	2.43%
	5,002,182	5,046,586	0.89%

Pension (5195)			
Electric	$621,423	($268,713)	-143.24%
Gas	529,280	(208,548)	-139.40%
	1,150,703	(477,261)	-141.48%

Post-retirement (5196)	
2011 Accual	$1,373,602
2012 Accuarey	3,058,320
Difference	$1,684,718
% Change	122.65%

401K(5197)			
Electric	$2,661,458	$3,150,800	18.39%
Gas	2,393,450	2,612,006	9.13%
Total	5,054,908	5,762,806	14.00%

Workers Compensation (5199)	$50,015
Gas Labor	$5,690,347
% Workers Comp to Labor	0.8789%

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC-046

Regarding: Regulated and non-regulated expenses
Witness: Jones

a. **How do employees report their time between regulated and non-regulated activities?**

b. **How are the travel costs for employees reported for regulated and non-regulated activities?**

c. **Provide an example of how this is reported.**

Response:

a-c. Please see Response No. PSC-039.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 8, 2013
DOCKET NO. D2012.9.100

PSC-049

Regarding: Rate Base
Witness: Applicable

Please provide a complete electronic copy of Statement C, Summary of Plant in Service-12 Month Average ended December 31, 2011, with supporting work papers and all links intact.

Response:

Please see Response No. PSC-001.

**MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100**

PSC-066

**Regarding: Transmittal Letter
Witness: Goodin**

On page 2 of the transmittal letter, MDU stated that its O & M costs have been reduced from $170 per customer to $141 per customer.

a. Is this over the entire MDU customer base or Montana specific?

b. Has the reduction been because of reduced maintenance, or more efficient operations? Please explain.

Response:

a. The amount represents Montana gas operations.

b. The reduction is the result of a continued effort to control costs through efficiencies and the use of technology. Please see the testimony of David L. Goodin, pages 8-9 for a description of some of the measures Montana-Dakota has undertaken to reduce costs.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-067

Regarding: Number of customers
Witness: Skabo

Please provide by each community, the number of customers now, and in the previous rate case.

Response:

Please see Attachment A for the number of customers from 2004 and 2011.

Company Name: Montana-Dakota Utilities Co.

MONTANA CUSTOMER INFORMATION

Year: 2004

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	219	136	19		155
2	Billings	89,847	41,123	3,945		45,068
3	Bridger	745	406	64		470
4	Crow Agency	1,552	317	65		382
5	Edgar	Not Available	103	8		111
6	Fromberg	486	274	21		295
7	Hardin	3,384	1,258	204		1,462
8	Joliet	575	346	44		390
9	Laurel	6,255	3,453	262		3,715
10	Park City	870	484	23		507
11	Pryor	628	89	13		102
12	Rockvale	Not Available	61	4		65
13	Silesia	Not Available	33	2		35
14	Warren	Not Available		2		2
15	Alzada	Not Available	10	7		17
16	Baker	1,695	793	171		964
17	Carlyle	Not Available	8	1		9
18	Fort Peck	240	127	10		137
19	Fairview	709	350	47		397
20	Forsyth	1,944	871	143		1,014
21	Frazer	452	90	15		105
22	Glasgow	3,253	1,641	298		1,939
23	Glendive	4,729	2,943	400		3,343
24	Hinsdale	Not Available	114	20		134
25	Ismay	26	8	4		12
26	Malta	2,120	986	194		1,180
27	Miles City	8,487	3,873	532		4,405
28	Nashua	325	178	19		197
29	Poplar	911	857	133		990
30	Richey	189	126	25		151
31	Rosebud	Not Available	43	6		49
32	Saco	224	42	6		48
33	Savage	Not Available	148	18		166
34	Sidney	4,774	2,249	393		2,642
35	Terry	611	311	62		373
36	St. Marie	183	145	10		155
37	Wibaux	567	211	51		262
38	Whitewater	Not Available	34	9		43
39	Wolf Point	2,663	1,384	198		1,582
40	MT Oil Fields	Not Available	2	3		5
41	**TOTAL Montana Customers**	138,663	65,627	7,451		73,078

1/ 2000 Census.

Company Name: Montana-Dakota Utilities Co.

MONTANA CUSTOMER INFORMATION

Year: 2011

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	218	126	17		143
2	Billings	104,170	45,504	4,488		49,992
3	Bridger	708	417	63		480
4	Crow Agency	1,616	298	77		375
5	Edgar	114	105	6		111
6	Fromberg	438	277	16		293
7	Hardin	3,505	1,245	197		1,442
8	Joliet	595	359	42		401
9	Laurel	6,718	3,834	272		4,106
10	Park City	983	630	27		657
11	Pryor	618	92	14		106
12	Rockvale	Not Available	69	4		73
13	Silesia	96	31	2		33
14	Warren	Not Available	0	2		2
15	Alzada	29	11	7		18
16	Baker	1,741	803	183		986
17	Carlyle	Not Available	7	1		8
18	Fort Peck	233	131	10		141
19	Fairview	840	374	57		431
20	Forsyth	1,777	866	153		1,019
21	Frazer	362	97	16		113
22	Glasgow	3,250	1,621	322		1,943
23	Glendive	4,935	3,097	424		3,521
24	Hinsdale	217	114	23		137
25	Ismay	19	11	5		16
26	Malta	1,997	994	202		1,196
27	Miles City	8,410	3,909	564		4,473
28	Nashua	290	162	24		186
29	Poplar	810	839	133		972
30	Richey	177	116	25		141
31	Rosebud	111	43	7		50
32	Saco	197	40	6		46
33	Savage	Not Available	148	20		168
34	Sidney	5,191	2,434	438		2,872
35	Terry	605	313	59		372
36	St. Marie	264	221	12		233
37	Wibaux	589	218	50		268
38	Whitewater	64	27	9		36
39	Wolf Point	2,621	1,351	203		1,554
40	MT Oil Fields	Not Available	1	3		4
41	**TOTAL Montana Customers**	154,508	70,935	8,183	0	79,118

1/ 2010 Census.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-095

Regarding: Time synchronization of salvage
Witness: Mulkern

Please state if retirements, gross salvage, and cost of removal are time-synchronized on MDU's books and records. If not, what are the average, shortest, and longest delays?

Response:

Typically gross salvage and cost of removal are recorded at the same time as the associated original cost of retirement within the same year of the completion date of the retirement portion of a construction project. It is the policy of the Company to retire plant in service and record corresponding cost of removal and gross salvage within one to three months of the date of completion. There is nothing on the Company records that can readily identify the length of any delays.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-104

Regarding: Salvage
Witness: Mulkern

a. For any sale of utility property since the Company's last litigated rate case, please state whether the gain or loss associated with such sale is contained in the accumulated provision for depreciation.

b. If not, identify the amount by year and by plant account associated with the plant retired and the account in which the gain or loss was booked.

c. Please state if and how the amount was or is to be passed on to customers.

d. Please provide all support and justification for such actions.

Response:

a. Gains and Losses are generally recorded in the accumulated reserve for depreciation unless associated with general plant land and structures or other property considered an operating unit or system that is greater than $50,000 of original cost. Gains and Losses from the sale of disposal of land, structures, or operating unit systems are recorded in FERC Account 421.

b. Please see Attachment A.

c. The net gain/loss is passed back to customers in general rate cases. Montana-Dakota includes in miscellaneous revenue a five year amortization of the net gains/losses on the sale of plant in the revenue requirement in general rate cases. Please see Statement H, page 6 and Statement Workpapers Statement H, pages H-61and H-62.

d. Please see Response No. PSC-102b.

Montana-Dakota Utilities Co.
Gain/Loss Detail-Allocated to UB-Montana Gas Book
2004-2012

Object Account	Sub Account	Asset/Category		2012	2011	2010	2009	2008	2007	2006	2005	2004
			Ledger Type	UB	UB	UB	UB	UB	UB	UB	UB	UB
			Year	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**	**2004**
			Format	YTD	YTD	YTD	YTD	YTD	YTD	YTD	YTD	YTD
			Period	8	12	12	12	12	12	12	12	12
			Currency	***	***	***	***	***	***	***	***	***
			Company	00001	00001	00001	00001	00001	00001	00001	00001	00001
			Business Unit	1	1	1	1	1	1	1	1	1
4211	*	*	**Gains**	13.18	(106,623.24)	326.00	(4,281.43)	-	(53,565.69)	(302,634.87)	-	-
4212	*	*	**Losses**	-	-	7,472.43	14,261.03	-	-	-	-	-
			Total	**13.18**	**(106,623.24)**	**7,798.43**	**9,979.60**	**-**	**(53,565.69)**	**(302,634.87)**	**-**	**-**

Asset Number	**Transaction Description**	2012	2011	2010	2009	2008	2007	2006	2005	2004
#110670	Sold Land-Adjacent to Glendive Service Center	13.18	(106,623.24)							
#150065	Sell Non-Utility Tools-Sheet Metal Brake-Forsyth			2,727.40						
#128199	Sell Non-Utility Tools-Refrigerant Tool-Wolf Point			1,516.50						
#145680	Sell Non-Utility Tools-Pittsburg Machine-Billings			1,132.82						
#145681	Sell Non-Utility Tools-Roper Whitney Brake-Billings			377.41						
#160581	Sell Non-Utility Tools-Lock Form Tin Seamer-Glasgow			1,657.99						
#146094	Retire Flagpole-MDUR Building			386.31						
#103366	Retire Leased CNG Equipment-Billings				(2.76)					
#327444	Retire Leased CNG Equipment-Billings				(1,722.76)					
#328588	Retire Leased CNG Equipment-Glendive				(2,555.91)					
#328546	Sold Land-Glasgow				13,250.00					
#327443	Sold Leased CNG Equipment-Billings				1,011.03					
#328816	Sold Hardin Office Building-Land						(1,440.07)			
#328817	Sold Hardin Office Building-Structure						(38,241.10)			
#331111	Sold Williston Gas Warehouse-Land						(2,543.65)			
#331112	Sold Williston Gas Warehouse-Structure						(11,340.87)			
#327433	Sold Billings Region Office-Land							(163,303.49)		
#327434	Sold Billings Region Office-Structure							(139,792.23)		
#132012	Sold Billings Region Office-Structure							460.85		
	Total	**13.18**	**(106,623.24)**	**7,798.43**	**9,979.60**	**-**	**(53,565.69)**	**(302,634.87)**	**-**	

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100

PSC-137

RE: Vehicle acquisition and use policy
Witness: Unknown

The Commission receives complaints from consumers who believe MDU's vehicle fleet is not well-matched for the jobs it must perform. In particular, these complaints often refer to the fact that large trucks are used to accomplish meter-reading tasks that could be accomplished by smaller vehicles.

a. Please respond to this criticism.

b. Please explain MDU's policy for the acquisition and use of vehicles.

Response:

a. Meter reading is accomplished in a variety of manners. In larger towns, a "fixed collector" which is permanently mounted and a network system is used which does not require anyone to drive or walk to collect the meter reads. In some instances where a fixed network system is not available or manual reads are necessary. Meter readers drive a small SUV or small pickup due to winter conditions and rural driving.

   To save the cost of locating a permanent meter reader in smaller communities and to avoid the cost of driving from the distant locations of Billings and Glendive, local service technicians will obtain meter reads. These individuals are assigned a vehicle, either a bucket truck, or a crew truck for their primary work requirements and those vehicles are used to obtain meter reads when necessary.

b. Please see Attachment A for Montana-Dakota's Procurement Procedure.

Procurement Procedure

CASCADE NATURAL GAS CORPORATION — In the Community to Serve® | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® | INTERMOUNTAIN® GAS COMPANY A Subsidiary of MDU Resources Group, Inc. In the Community to Serve® | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

Title: **Passenger Automotive and Light Truck Purchases**

Procedure Number: **5001.1** Revision Date: 05/01/11

Revision Summary

Initial Procedure

References:

Policy

AD 100 - Approval Authorization Policy

Additional Instructions: None

Purpose:

Establish procedures to be followed by MDU Utilities Group employees in the purchase of company passenger automobiles and light trucks.

Scope:

The provisions set forth in this procedure apply to the purchase of all passenger automobiles and light trucks less than 1-ton capacity. (Rate Classes 4-16). Also classified as all non-Commercial Motor Vehicles. (For purchases of vehicles in Rate Classes 18-43; Medium & Heavy Duty Trucks, Work Equipment, and Trailers refer to Procurement Procedure No. 5002).

Recognized Exceptions:

None

General:

1. Acquisition

   1.1 To initiate a vehicle purchase, the Region, Power Plant, or General Office Management notifies the Fleet Department of their need. The need for new or replacement units are primarily predetermined in the budgeting and forecasting process performed annually between the Fleet Department and Region/G.O. Management, reviewed and approved by the respective business segment Vice President. All emergency replacements or non-budget requirements will follow the guidelines as set forth in the Approval Authorization Policy.

   A. Upon determination of the type of unit required, the Fleet Department will create a specification. Cost and option comparisons will then be made between the auto makers, utilizing those of which MDU Resources has a National Account, where applicable. This cost comparison for the auto and light truck, shall include the Competitive Price Allowances (CPA) off invoice of said unit, which are pre-determined by MDU Resources National Account agreements, in place with the auto manufacturer(s) for the model year. Other deductions offered by the fleet acquisition company, if applicable, shall also be reflected in the cost breakdown.

   i. When cost effective, vehicles may also be purchased from franchised dealer auctions. A franchised dealer will make such purchases at the request of the Director of Administrative Services. Vehicle cost shall be the auction price plus a negotiated dealer markup under $500, freight and dealers purchase fee.

   ii. In situations where standard lead times for a vehicle order cannot be waited upon, or a dealer stock unit meets all specification criteria, a dealer 'off-lot' purchase may be made. In some cases, the CPA incentives can still be obtained from auto makers, with the loss of other negotiated pricing discounts. In other cases, incentive pricing may be limited or may not exist at all.

B. Should a service body or other modification be required for the unit, and shipping through a manufacturing facility prior to delivery is not used, competitive quotes shall be obtained from body companies in the most practical proximity to the location where the unit will be used, with respect to pricing. Logistics shall be arranged by the Fleet Department.

C. Upon determining the most prudent and practical specification, and mutual agreement between the Management and Fleet personnel, a work authorization is created by the Fleet Department and routed for proper approval.

   i. Extenuating circumstances for replacement/purchase of units not forecasted or budgeted may occur on occasion. The process stated above will be followed in these situations, and all efforts shall be made to stay within the budget constraints for the year. Should it not be possible to stay within these constraints, a Non-Budget work authorization shall be created and routed for approval.

D. After approval of the authorization, a Purchase Order(s) is/are created for the vehicle (and body/up fit, if applicable). Once approved and processed by the Procurement Department, vendors shall be notified. Orders shall be placed using the fleet acquisition company, of which MDU Resources has a National Account in place, whenever possible.

E. Delivery location of the unit will be to the nearest or practical auto dealer to where the unit will be used or serviced. The fleet acquisition company will pay said dealer a "Courtesy Delivery Fee" for handling delivery of the unit(s). This fee is negotiated between the delivery dealer and the fleet acquisition company. (If unit is purchased via dealer auction, delivery to a company specified location shall occur).

F. If the unit will require up-fitting, delivery to the nearest dealer of the up-fit facility will be used, dependent on business relationship.

2. Disposal

2.1 Company vehicles removed from service shall be remarketed/disposed as follows:

A. *Sale to another MDUR subsidiary at fair market value*, as determined by the Director of Administrative Services, referencing Blackbook or N.A.D.A. valuation guides.

B. *Outright sales to employees and the general public* using the MDUR Surplus Auction site. Auction frequency shall be determined by the Fleet Department, based upon volume of assets to remarket.

   i. A vehicle posting shall be prepared describing the unit in detail. The Fleet Department will be responsible for determining minimum sales price of the used vehicle, and final acceptable price if lower than the published minimum. After the sale, a bill of sale is signed by the buyer and a retirement work authorization is created. History of auction results will be retained electronically in the MDUR "Surplus" Auction site for a period of at least one year.

C. *By consignment to a reputable auction house*, as approved by the Director of Administrative Services.

   i. In geographic areas where vehicle auctions are available, this means of sale may be used, if deemed the best method to obtain maximum residual value. As with the outright sale, a minimum selling price will be established prior to committing a vehicle to auction.

Procurement Procedure

CASCADE NATURAL GAS CORPORATION — In the Community to Serve
GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve
INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. In the Community to Serve
MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve

Title: **Passenger Automotive and Light Truck Purchases**

Procedure Number: **5001.1** Revision Date: 05/01/11

After the sale, a retirement work authorization is prepared and records of the transaction are kept on file.

D. *Scrapped/Junked*, as determined by the Director of Administration Services.

i. If either safety or liability reasons prevent an asset from being remarketed by above methods, the Fleet Department shall arrange for disposal via a reputable scrap/junk yard. Competitive bids shall be called for in areas where multiple scrap yards exist. This most commonly occurs after a vehicle has been in an accident. After the sale, a retirement work authorization is prepared and records of the transaction are kept on file.

Procedures:

1.1 Region/General Office Manager

A. Communicate request for vehicle purchase specification to Fleet Department personnel.

B. Fleet Department may also proactively contact Managers based upon predetermined fleet budget.

1.2 Fleet Department

A. Analyze and evaluate vehicle costs and select vehicle which provides best value and meets job requirements.

B. Create a work authorization and route for approval.

C. Create Purchase Order and route for approval.

1.3 Director of Administrative Services to VP of Operations and VP of Power Production.

A. Review paper work authorization, electronic purchase order requests, and vehicle specifications; Approve (or reject for needed changes).

1.4 Procurement Department

A. Review purchase order request for completeness and approvals. Expedite the purchase order in accordance with Procurement Procedure 5000.

Approval Levels:

Requests for vehicles require approval in accordance with the provisions of the "Procurement Department Approvals of Purchase Orders" section of the ***Approval Authorization Policy AD 100***.

Responsibility:

Establishment and implementation of procedures to administer the policy and procedure are the responsibility of the Executive VP-Combined Utility Operations Support, through the Director of Administrative Services.

Reviewed: ______________________
Director of Administrative Services

Date: 6/22/11

Approved: ______________________
Executive VP-Combined Utility Operations Support

Date: 6/22/11

**MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED JANUARY 21, 2013
DOCKET NO. D2012.9.100**

PSC-146

RE: Departmental Expenses
Witness: Applicable

Please provide the jurisdictional breakdown of the departmental expense summaries and the allocation to MT gas rate payers.

a. Please define "premium time."

Response:

A jurisdictional breakdown of departmental expense is not available. Expenses are available on a jurisdictional basis by FERC account and resource, but not by department.

a. Premium time is overtime.