MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES
ELECTRIC UTILITY - NORTH DAKOTA

Acct. No.	Account	Proposed Depreciation Rate	Settlement Deprecation Rate	Rate Change
	Miles City Turbine			
341	Structures & Improvements	1.05%	1.05%	
342	Fuel Holders, Producers & Acces.	5.36%	5.36%	
344	Generators	2.24%	2.24%	
345	Accessory Equipment	8.27%	8.27%	
346	Miscellaneous Equipment	4.11%	4.11%	
	Portable Generators			
341	Structures & Improvements	3.03%	3.03%	
342	Fuel Holders, Producers & Acces.	3.01%	3.01%	
344	Generators	3.05%	3.05%	
345	Accessory Equipment	4.20%	4.20%	
	Diamond Willow Wind			
341	Structures & Improvements	3.39%	3.39%	
344	Generators	3.67%	3.67%	
345	Accessory Equipment	5.02%	5.02%	
346	Miscellaneous Equipment	4.29%	4.29%	
	Ormat			
341	Structures & Improvements	3.29%	3.29%	
344	Generators	3.39%	3.39%	
345	Accessory Equipment	4.24%	4.24%	
	Cedar Hills Wind			
341	Structures & Improvements	3.91%	3.91%	
344	Generators	3.86%	3.86%	
345	Accessory Equipment	4.94%	4.94%	
346	Miscellaneous Equipment	5.81%	5.81%	
	Thunder Spirit Wind			
341	Structures & Improvements	4.90%	4.90%	
344	Generators	3.96%	3.96%	
345	Accessory Equipment	6.70%	6.70%	
346	Miscellaneous Equipment	5.11%	5.11%	

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES
ELECTRIC UTILITY - NORTH DAKOTA

Acct. No.	Account	Proposed Depreciation Rate	Settlement Deprecation Rate	Rate Change
	Heskett Unit III Gas Turbine			
341	Structures & Improvements	2.97%	2.97%	
342	Fuel Holders, Producers & Acces.	3.10%	3.10%	
344	Generators	2.31%	2.31%	
345	Accessory Equipment	5.48%	5.48%	
346	Miscellaneous Equipment	3.81%	3.81%	
	Heskett Unit IV Gas Turbine			
344	Generators	2.33%	2.33%	
	Lewis & Clark Unit II RICE			
341	Structures	3.78%	3.78%	
342	Fuel Holders, Producers & Acces.	3.66%	3.66%	
344	Generators	3.64%	3.64%	
345	Accessory Equipment	5.07%	5.07%	
346	Miscellaneous Equipment	4.55%	4.55%	
	Transmission Plant			
350.2	Rights of Way	1.29%	1.29%	
352	Structures & Improvements	2.00%	2.00%	
353	Station Equipment	1.47%	0.73%	-0.74%
354	Towers & Fixtures	1.90%	1.90%	
355	Poles & Fixtures	2.06%	1.92%	-0.14%
356	Overhead Conductor & Devices	1.64%	1.45%	-0.19%
357	Underground Conduit	1.99%	1.99%	
358	Underground Conductor & Devices	1.99%	1.99%	
	Distribution Plant			
360.2	Rights of Way	0.83%	0.83%	
362	Station Equipment	2.05%	0.83%	-1.22%
364	Poles, Towers & Fixtures	3.76%	2.71%	-1.05%
365	Overhead Conductors & Devices	3.08%	2.35%	-0.73%
366	Underground Conduit	1.53%	1.53%	
367	Underground Conductor & Devices	4.07%	1.60%	-2.47%
368	Line Transformers	2.16%	1.89%	-0.27%
369	Services	2.29%	2.08%	-0.21%
370	Meters	7.41%	7.41%	
371	Installation on Cust. Premises	9.52%	7.16%	-2.36%
373	Street Lighting & Signal System	4.27%	3.20%	-1.07%

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES
ELECTRIC UTILITY - NORTH DAKOTA

Acct. No.	Account	Proposed Depreciation Rate	Settlement Deprecation Rate	Rate Change
	General Plant			
390	Structures & Improvements	1.54%	1.54%	
391.1	Office Furniture & Equipment	8.30%	8.30%	
391.3	Computer Equip. - PC	0.00%	0.00%	
391.4	Computer Equip. - Prime	57.10%	57.10%	
391.5	Computer Equip. - Other	12.10%	12.10%	
392.1	Trans. Equip., Non - Unitized	0.00%	0.00%	
392.2	Trans. Equip., Unitized	9.63%	9.63%	
393	Stores Equipment	1.65%	1.65%	
394.1	Tools, Shop & Garage Equip.	4.82%	4.82%	
395	Laboratory Equipment	10.31%	10.31%	
396.1	Trailers-Work Equipment	2.94%	2.94%	
396.2	Power Operated Equipment	8.22%	8.22%	
397.1	Radio Communication Equip. - Fixed	6.98%	6.98%	
397.2	Radio Communication Equip. - Mobile	6.87%	6.87%	
397.3	General Telephone Comm. Equip.	7.42%	7.42%	
397.4	Carrier Current Comm. Equip.	0.00%	0.00%	
397.5	Supervisory & Telemetering Equip.	14.27%	14.27%	
397.6	Scada System	9.79%	9.79%	
397.8	Network Equipment	22.87%	22.87%	
397.9	Transfer Trip Communication Equip.	0.00%	0.00%	
398	Miscellaneous Equipment	3.83%	3.83%	
	Common Plant - Electric			
390	Structures & Improvements	0.85%	0.85%	
391.1	Office Furniture & Equipment	6.67%	6.67%	
391.3	Computer Equip. - PC	20.00%	20.00%	
391.4	Computer Equip. - Prime	0.00%	0.00%	
391.5	Computer Equip. - Other	20.00%	20.00%	
392.1	Transport Equip. - Trailers	0.00%	0.00%	
392.2	Transport Equip.-Vehicles	6.65%	6.65%	
392.3	Aircraft Equipment	4.00%	4.00%	
393	Stores Equipment	3.33%	3.33%	
394.1	Tools, Shop & Garage Equip.	5.56%	5.56%	
394.3	Vehicle Maintenance Equipment	5.00%	5.00%	
394.4	Vehicle Refueling Equipment	5.00%	5.00%	
397.1	Radio Communication Equip. - Fixed	6.67%	6.67%	
397.2	Radio Communication Equip. - Mobile	6.67%	6.67%	
397.3	General Telephone Comm. Equip.	10.00%	10.00%	

MONTANA-DAKOTA UTILITIES CO.
DEPRECIATION RATES
ELECTRIC UTILITY - NORTH DAKOTA

Acct. No.	Account	Proposed Depreciation Rate	Settlement Deprecation Rate	Rate Change
397.5	Supervisory & Telemetering Equip.	6.67%	6.67%	
397.8	Network Equipment	20.00%	20.00%	
398	Miscellaneous Equipment	5.00%	5.00%	

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Overall Bill Impact - Settlement
Case No. PU-22-194

	Revenue at Current Rates				Generation Resource Recovery Rider (GRRR)							
Rate Class	Projected 2023 Revenue at Current Rates 1/	Rider Revenue 2/	Total Revenue	Rate Design Increase 3/	Proposed GRRR Revenue	GRRR at Current Rates	Net Increase In GRRR 4/	Proposed Increase	Total Proposed Revenue	Overall Bill Impact	Base Rate Bill Impact	GRRR Bill Impact
Residential Service	$69,769,528	$12,977,876	$82,747,404	$6,107,895	$3,221,567	$1,427,566	$1,794,001	$7,901,896	$90,649,300	9.5%	7.4%	2.2%
Small General Service	10,414,218	1,615,247	12,029,465	943,338	400,961	177,679	223,282	1,166,620	13,196,085	9.7%	7.8%	1.9%
General Service	88,497,679	17,403,425	105,901,104	3,559,567	4,014,827	1,763,008	2,251,819	5,811,386	111,712,490	5.5%	3.4%	2.1%
Municipal Lighting	980,235	183,996	1,164,231	78,471	17,434	11,153	6,281	84,752	1,248,983	7.3%	6.7%	0.5%
Municipal Pumping	2,878,349	613,256	3,491,605	199,587	168,837	67,663	101,174	300,761	3,792,366	8.6%	5.7%	2.9%
Outdoor Lighting Service	362,968	60,721	423,689	8,823	5,230	3,672	1,558	10,381	434,070	2.5%	2.1%	0.4%
Total North Dakota Electric	$172,902,977	$32,854,521	$205,757,498	$10,897,681	$7,828,856	$3,450,741	$4,378,115	$15,275,796	$221,033,294	7.4%	5.3%	2.1%

1/ Statement F, Schedule F-1, Page 1 Includes Generation Resource Recovery Rider revenue.
2/ Transmission Cost Adjustment and Reneweable Resource Cost Adjustment revenue reflecting current rates.
3/ Includes the $3,450,741 currently being recovered through the Generation Resource Recovery Rider that will be collected through base rates.
4/ Reflects the net increase for the GRRR as $3,450,741 is already reflected in the current GRRR rates.

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Estimated Residential Bill Increases - Settlement
2023

		Current Rates					Proposed Rates				
	Kwh	Base Rate	Energy	Riders	FPP Charge	Total Current Bill	Base Rate	Energy	Riders	FPP Charge	Total Proposed Bill
January	1,000	$14.26	$49.28	$18.87	$22.41	$104.82	$15.53	$55.71	$21.22	$22.41	$114.87
February	1,000	12.88	49.28	18.87	22.41	103.44	14.03	55.71	21.22	22.41	113.37
March	1,000	14.26	49.28	18.87	22.41	104.82	15.53	55.71	21.22	22.41	114.87
April	700	13.80	39.75	13.21	15.69	82.45	15.03	44.25	14.85	15.69	89.82
May	600	14.26	34.07	11.32	13.45	73.10	15.53	37.93	12.73	13.45	79.64
June	700	13.80	39.75	13.21	15.69	82.45	15.03	44.25	14.85	15.69	89.82
July	800	14.26	45.42	15.10	17.93	92.71	15.53	50.57	16.98	17.93	101.01
August	1,000	14.26	56.78	18.87	22.41	112.32	15.53	63.21	21.22	22.41	122.37
September	700	13.80	39.75	13.21	15.69	82.45	15.03	44.25	14.85	15.69	89.82
October	600	14.26	34.07	11.32	13.45	73.10	15.53	37.93	12.73	13.45	79.64
November	600	13.80	34.07	11.32	13.45	72.64	15.03	37.93	12.73	13.45	79.14
December	900	14.26	46.60	16.98	20.17	98.01	15.53	52.39	19.10	20.17	107.19
	9,600	$167.90	$518.10	$181.15	$215.16	$1,082.31	$182.86	579.84	$203.70	215.16	$1,181.56
	800										
Change by Component							$14.96	$61.74	$22.55	$0.00	$99.25
											9.2%
										Per Month	$8.27

	Current	Proposed
Basic Service Charge/ Day	$0.46	$0.501
Monthly Service Charge	$13.99	$15.24
Energy		
1st 750 winter & summer	$0.05678	$0.06321
Over 750 winter	0.02678	0.03321
TCA	0.00801	0.00801
ECRR	0.00000	0.00000
GRRR	0.00187	0.00422
Renewable Rider	0.00899	0.00899
Fuel	0.02241	0.02241
Total Riders (excl Fuel)	0.01887	0.02122

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MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Allocation of Revenues - Settlement
Projected 2023

Rate Class	Bill Determinants	Kwh	KW	Basic Service Charge	Energy	Demand	Generation Rider	Fuel Rev	Total
	Projected 2023 Billing Determinants and Revenues								
Residential Service									
Rate 10	80,161	763,201,099		$13,459,178	$37,765,785		$1,427,186	$17,103,337	$69,755,486
Rate 13	4	132,692		1,095	4,410		248	2,974	8,727
Rate 16	4	70,679		1,095	2,504		132	1,584	5,315
Total Residential	80,169	763,404,470		13,461,368	37,772,699		1,427,566	17,107,895	69,769,528
Small General Service									
Rate 20	10,410	88,215,802		3,191,779	4,491,252		164,964	1,976,916	9,824,911
Rate 26	270	1,950,557		98,550	62,141		3,648	43,712	208,051
Subtotal	10,680	90,166,359		3,290,329	4,553,393		168,612	2,020,628	10,032,962
Rate 25	49	1,577,312	10,040.6	26,828	2,934	31,943	2,950	35,348	100,003
Rate 40	271	3,270,836	7,220.9	85,308	69,942	46,587	6,117	73,299	281,253
Total Small General	11,000	95,014,507	17,261.5	3,402,465	4,626,269	78,530	177,679	2,129,275	10,414,218
Large General Service									
Rate 30 Primary	40	226,484,074	507,095.6	48,000	3,202,485	6,098,111	279,973	4,935,088	14,563,657
Rate 30 Secondary	4,566	722,746,179	2,202,914.3	3,068,991	16,847,213	23,251,782	1,216,251	16,196,742	60,580,979
Rate 31 Primary	1	2,478,000	4,869.6	1,164	35,258	64,936	2,689	53,996	158,043
Rate 31 Secondary	52	13,853,295	38,840.3	44,928	323,025	474,070	21,444	310,452	1,173,919
Rate 32 Secondary	603	57,227,301	270,437.7	151,956	1,386,045	722,295	65,470	1,282,464	3,608,230
Subtotal	5,262	1,022,788,849	3,024,158	3,315,039	21,794,026	30,611,194	1,585,827	22,778,742	80,084,828
Contract Rate - Tesoro	1	98,750,754	161,517.3	1,200	1,575,291	1,056,761	89,175	2,151,779	4,874,206
Contract Rate - Sabin	1	27,167,840	55,224.9	1,200	447,472	367,729	30,490	591,987	1,438,878
Rate 38	4	31,986,100	104,174.7	7,140	400,466	937,668	57,516	696,977	2,099,767
Rate 39	0	0	0.0	0	0	0	0	0	0
Total Large General	5,268	1,180,693,543	3,345,074	3,324,579	24,217,255	32,973,352	1,763,008	26,219,485	88,497,679
Municipal Lighting									
Rate 41 Primary	44	1,174,555			53,865		975	25,594	80,434
Rate 41 Secondary	598	12,133,777			617,705		10,178	271,918	899,801
Total Municipal Lighting	642	13,308,332			671,570		11,153	297,512	980,235
Municipal Pumping									
Rate 48 Primary	5	23,520,600	50,995.4	4,320	380,563	331,482	25,340	512,514	1,254,219
Rate 48 Secondary	303	22,345,983	83,684.9	152,558	388,173	540,303	42,323	500,773	1,624,130
Total Municipal Pumping	308	45,866,583	134,680.3	156,878	768,736	871,785	67,663	1,013,287	2,878,349
Outdoor Lighting Service									
Rate 52 Primary	13	34,081			2,167		31	743	2,941
Rate 52 Secondary	2,539	3,958,084			267,685		3,641	88,701	360,027
Total Outdoor Lighting	2,552	3,992,165			269,852		3,672	89,444	362,968
Total North Dakota Electric	99,939	2,102,279,600	3,497,016.2	$20,345,290	$68,326,381	$33,923,667	$3,450,741	$46,856,898	$172,902,977
	Overall ROR				7.513%				
	Inverse of Tax Rate				75.5951%				

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MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Allocation of Revenues - Settlement
Projected 2023

Rate Class	Allocation of Revenues 1/	Rate Design Results Base Revenue Increase $	%	ROR	Generation Rider Revenue $	Total Revenue Increase $
Residential Service						
Rate 10	$4,679,447	$4,679,806	6.7%			
Rate 13	510	192	2.2%			
Rate 16	332	331	6.2%			
Total Residential	$4,680,289	4,680,329	6.7%	3.7%	$3,221,567	$7,901,896
Small General Service						
Rate 20	710,452	710,348	7.2%			
Rate 26	14,755	14,748	7.1%			
Subtotal	725,207	725,096	7.2%	5.6%	$380,502	$1,105,598
Rate 25	9,591	9,583	9.6%		6,656	16,239
Rate 40	30,986	30,980	11.0%		13,803	44,783
Total Small General	765,784	765,659	7.4%	5.3%	$400,961	$1,166,620
Large General Service						
Rate 30 Primary	538,558	537,171	3.7%		$635,700	$1,172,871
Rate 30 Secondary	868,332	872,335	1.4%		2,761,595	3,633,930
Rate 31 Primary	2,213	3,503	2.2%		6,105	9,608
Rate 31 Secondary	16,968	15,725	1.3%		48,691	64,416
Rate 32 Secondary	141,648	141,000	3.9%		160,432	301,432
Subtotal	1,567,719	1,569,734	2.0%	9.7%	$3,612,523	$5,182,257
Contract Rate - Tesoro	151,977	152,341	3.1%		202,480	354,821
Contract Rate - Sabin	47,216	47,231	3.3%		69,230	116,461
Rate 38	27,297	27,253	1.3%		130,594	157,847
Rate 39						
Total Large General	1,794,209	1,796,559	2.0%	9.2%	$4,014,827	$5,811,386
Municipal Lighting						
Rate 41 Primary	5,990					
Rate 41 Secondary	61,301					
Total Municipal Lighting	67,291	67,316	6.9%	10.6%	$17,434	$84,752
Municipal Pumping						
Rate 48 Primary	109,925					
Rate 48 Secondary	22,133					
Total Municipal Pumping	132,058	131,924	4.6%	6.5%	$168,837	$300,761
Outdoor Lighting Service						
Rate 52 Primary	42					
Rate 52 Secondary	5,122					
Total Outdoor Lighting	5,164	5,151	1.4%	7.7%	$5,230	$10,381
Total North Dakota Electric	$7,444,795	$7,446,940	4.3%	6.3%	$7,828,856	$15,275,796

1/ Settlement revenues allocated based on allocation of revenues in original filing.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTLITY - NORTH DAKOTA

Derivation of Generation Resource Recovery Rider Rates - Settlement
Proposed 2023

Total Cost to be Recovered through GRRR Rates	$7,832,580

Allocation of Costs & Proposed Rates	Allocated GRRR Costs 1/	Projected Billing Determinants		Proposed GRRR Rates	
Residential & Small General	$3,626,277	858,418,977	Kwh	$0.00422	per Kwh
Large General	4,023,231	3,209,317.0	KW	$1.25361	per KW
Space Heating Rate 32	160,431	270,437.7	KW	$0.59323	per KW
Lighting	22,641	17,300,497	Kwh	$0.00131	per Kwh
	$7,832,580				

Change in Rates	Proposed GRRR Rates	Current GRRR Rates 2/	Change In GRRR Rates
Residential & Small General	$0.00422	$0.00185	$0.00237
Large General	$1.25361	$0.54680	$0.70681
Space Heating Rate 32	$0.59323	$0.23976	$0.35347
Lighting	$0.00131	$0.00091	$0.00040

1/ Demand Allocation Factor 2:

Residential & Small General	46.297343%	(Rates 10, 13, 16, 20, 25, 26, and 40)
Large General	51.365337%	(Rates 30, 31, 38, 48, and contracts)
Space Heating Rate 32	2.048257%	(Rate 32)
Lighting	0.289063%	(Rates 41, 52)
	100.000000%	

2/ Current rates effective February 1, 2022.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
Summary of Proposed Charges - Settlement
Projected 2023

							Demand Charges			
	Basic Service	Energy Charges		Base	Total Energy		1st Block		2nd Block	
Rate Class	Charge	Summer	Winter	Fuel	Summer	Winter	Summer	Winter	Summer	Winter
Residential										
Rate 10	$0.501									
1st 750		$0.06321	$0.06321	$0.02241	$0.08562	$0.08562				
Over 750		0.06321	0.03321	0.02241	0.08562	0.05562				
Rate 13	0.791									
Off Peak		0.06321	0.01100	0.02241	0.08562	0.03341				
On Peak										
1st 750		0.06321	0.06321	0.02241	0.08562	0.08562				
Over 750		0.06321	0.03321	0.02241	0.08562	0.05562				
TOD Rate 16	0.791									
Off Peak		0.04789	0.03289	0.02241	0.07030	0.05530				
On Peak		0.07789	0.06289	0.02241	0.10030	0.08530				
Small General Service										
Rate 20	1.15									
1st 750		0.05654	0.05654	0.02241	0.07895	0.07895				
Over 750		0.05654	0.02654	0.02241	0.07895	0.04895				
Irrigation Rate 25	1.90	0.00126	0.00126	0.02241	0.02367	0.02367	4.88	1.88	4.88	1.88
TOD Rate 26	1.25									
Off Peak		0.03246	0.01746	0.02241	0.05487	0.03987				
On Peak		0.05746	0.04246	0.02241	0.07987	0.06487				
Municipal Rate 40										
Non- Demand	1.15									
1st 750		0.03365	0.03365	0.02241	0.05606	0.05606				
Over 750		0.03365	0.02265	0.02241	0.05606	0.04506				
Demand	1.30						12.93	0.00	12.93	9.93
1st 750		0.01265	0.01265	0.02241	0.03506	0.03506				
Over 750		0.01265	0.01265	0.02241	0.03506	0.03506				
Large General Service										
Rate 30 Primary Service	108.03	0.01538	0.01538	0.02179	0.03717	0.03717	15.05	12.05	15.05	12.05
Rate 30 Secondary Servic	58.72	0.02444	0.02444	0.02241	0.04685	0.04685	13.01	10.01	13.01	10.01
TOD Rate 31										
Primary Service	97.00									
Off Peak		0.01544	0.01544	0.02179	0.03723	0.03723	0.00	0.00	0.00	0.00
On Peak		0.01794	0.01794	0.02179	0.03973	0.03973	15.57	12.57	15.57	12.57
Secondary Service	72.00									
Off Peak		0.02449	0.02449	0.02241	0.04690	0.04690	0.00	0.00	0.00	0.00
On Peak		0.02699	0.02699	0.02241	0.04940	0.04940	15.04	11.04	15.04	11.04
Space Heating Rate 32										
Primary Service	23.00	0.01569	0.01569	0.02179	0.03748	0.03748	15.05	1.38	15.05	1.38
Secondary Service	23.00	0.02569	0.02569	0.02241	0.04810	0.04810	13.01	1.38	13.01	1.38
Contract Rate 304	108.03									
1st 2.3 million Kwh		0.01879	0.01879	0.02179	0.04058	0.05937	$9.06	$6.04	$6.04	$6.04
Over 2.3 million Kwh		0.01354	0.01354	0.02179	0.03533	0.04887	9.06	6.04	6.04	6.04

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
Summary of Proposed Charges - Settlement
Projected 2023

Rate Class	Basic Service Charge	Energy Charges Summer	Energy Charges Winter	Base Fuel	Total Energy Summer	Total Energy Winter	Demand Charges 1st Block Summer	Demand Charges 1st Block Winter	Demand Charges 2nd Block Summer	Demand Charges 2nd Block Winter
Contact Rate 303	$108.03									
1st 1.5 million Kwh		$0.02333	$0.02333	$0.02179	$0.04512	$0.04512	$9.04	$5.74	$9.04	$5.74
Over 1.5 million Kwh		0.01657	0.01657	0.02179	0.03836	0.03836	9.04	5.74	9.04	5.74
Demand Resp Rate 38	108.03	0.01344	0.01344	0.02179	0.03523	0.03523	11.55	8.55	11.55	8.55
Municipal Lighting - Rate 41										
Primary Service		0.05180	0.05180	0.02179	0.07359	0.07359				
Secondary Service		0.05680	0.05680	0.02241	0.07921	0.07921				
Municipal Pumping - Rate 48										
Primary Service	60.00	0.01394	0.01394	0.02179	0.03573	0.03573	12.00	9.00	12.00	9.00
Secondary Service	45.00	0.01494	0.01494	0.02241	0.03735	0.03735	12.00	9.00	12.00	9.00
Outdoor Lighting - Rate 52										
Primary Service		0.06578	0.06578	0.02179	0.08757	0.08757				
Secondary Service		0.06984	0.06984	0.02241	0.09225	0.09225				

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Residential Electric Service Rate 10 - Settlement
Projected 2023

Residential Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge - Rate 10	80,161	$0.46	per day	$13,459,032	$0.501	per day	$14,658,641
Rate 95	8	0.05	per day	146	0.05	per day	146
Energy							
Summer	255,122,863	$0.05676	per Kwh	14,485,876	$0.06321	per Kwh	16,126,316
Winter							
First 750	322,452,465	$0.05678	per Kwh	18,308,851	$0.06321	per Kwh	20,382,220
Over 750	185,625,771	0.02678	per Kwh	4,971,058	0.03321	per Kwh	6,164,632
Subtotal	508,078,236			23,279,909			26,546,852
Generation Rider				1,427,186			
Total Energy	763,201,099			39,192,971			42,673,168
Base Fuel	763,201,099	$0.02241	per Kwh	17,103,337	$0.02241	per Kwh	17,103,337
Total Rate 10				$69,755,486			$74,435,292
Total Revenues Per Design							$74,435,292
Target Revenues							74,434,933
Difference							$359

Derivation of Rate:

				Projected
Projected Revenues Before Increase				$69,755,486
Proposed Revenue Increase				4,679,447
Total Revenue Requirement				74,434,933
Less:				
Proposed Basic Service Charge Revenues				14,658,787
Projected Base Fuel				17,103,337
Winter Rate >750 differential	($0.03000)	185,625,771	Kwh	(5,568,773)
Subtotal				26,193,351
Net to be Collected Through Energy				$48,241,582
Total Kwh				763,201,099
Summer Rate per Kwh				$0.06321
Winter Rate Per Kwh - 1st 750 Kwh				$0.06321
Winter Rate - Over 750 Kwh				$0.03321

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Residential Electric Service Rate 13 - Settlement
Projected 2023

Residential Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge - Rate 13	4	$0.75	per day	$1,095	$0.791	per day	$1,155
Energy							
Summer	26,963	$0.05846	per Kwh	1,693	$0.06321	per Kwh	1,831
Winter							
On-Peak First 750	22,786	$0.05846	per Kwh	1,332	$0.06321	per Kwh	1,440
On-Peak Over 750	28,310	0.02846	per Kwh	806	0.03321	per Kwh	940
Off Peak	52,633	0.01100	per Kwh	579	0.01100	per Kwh	579
Subtotal	103,729			2,717			2,959
Generation Rider				248			
Total Energy	132,692			4,658			4,790
Base Fuel	132,692	$0.02241	per Kwh	2,974	$0.02241	per Kwh	2,974
Total Rate 13				$8,727			$8,919
Total Revenues Per Design							$8,919
Target Revenues							9,237
Difference							($318)

Derivation of Rate:

				Projected
Projected Revenues Before Increase				$8,727
Proposed Revenue Increase				510
Total Revenue Requirement				9,237
Less:				
Proposed Basic Service Charge Revenues				1,155
Projected Base Fuel				2,974
Winter Off-Peak				579
Winter >750 differential	($0.03000)	28,310	kwh	(849)
Subtotal				3,859
Net to be Collected Through Energy				$5,378
Total Kwh (excluding Winter Off-Peak)				80,059
Summer rate				$0.06718
Winter On-Peak First 750				$0.06718
Winter On-Peak > 750				$0.03718
Winter Off-Peak Rate				$0.01100

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Residential Electric TOD Service Rate 16 - Settlement
Projected 2023

Residential Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge	4	$0.75	per day	$1,096	$0.791	per day	$1,155
Energy							
Summer							
On-Peak Kwh	3,277	$0.07218	per Kwh	237	$0.07769	per Kwh	255
Off Peak Kwh	8,734	0.04218	per Kwh	368	0.04769	per Kwh	418
Subtotal	12,011			606			673
Winter							
On-Peak Kwh	10,152	$0.05718	per Kwh	580	$0.06289	per Kwh	638
Off Peak Kwh	48,516	0.02718	per Kwh	1,319	0.03289	per Kwh	1,596
Subtotal	58,668			1,899			2,234
Generation Rider				132			
Total Energy	70,679			2,636			2,907
Base Fuel	70,679	$0.02241	per Kwh	1,584	$0.02241	per Kwh	1,584
Total Rate 16 Revenues				$5,315			$5,646

Total Revenues Per Design	$5,646
Target Revenues	5,647
Difference	($1)

Derivation of Rate:

				Projected
Projected Revenues Before Increase				$5,315
Proposed Revenue Increase				332
Total Revenue Requirement				5,647
Less:				
Proposed Basic Service Charge Revenues				1,155
Projected Base Fuel				1,584
Winter Differential	($0.01500)	58,668	Kwh	(880)
On-Peak Differential	$0.03000	13,429	Kwh	403
				2,262
Net to be Collected Through Energy				$3,385
Total On-Peak Kwh				70,679
Summer Off-Peak Rate				$0.04769
Summer On-Peak Rate				$0.07769
Winter Off-Peak Rate				$0.03289
Winter On-Peak Rate				$0.06289

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Small General Electric Service Rate 20 - Settlement
Projected 2023

Small General Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge	10,410	$0.84	per day	$3,191,706	$1.15	per day	$4,369,598
Rate 95	4	0.05	per day	73	0.05	per day	73
Energy							
Summer	28,079,972	$0.05997	per Kwh	1,683,956	$0.05654	per Kwh	1,587,642
Winter							
First 750 Kwh	33,500,833	$0.05997	per Kwh	2,009,045	$0.05654	per Kwh	1,894,137
Over 750 Kwh	26,634,997	0.02997	per Kwh	798,251	0.02654	per Kwh	706,893
Subtotal	60,135,830			2,807,296			2,601,030
Generation Rider				164,964			
Total Energy	88,215,802			4,656,216			
Base Fuel	88,215,802	$0.02241	per Kwh	1,976,916	$0.02241	per Kwh	1,976,916
Total Rate 20 Revenues				$9,824,911			$10,535,259

Total Revenues Per Design	$10,535,259
Target Revenues	10,535,363
Difference	($104)

Derivation of Rate:

			Projected
Projected Revenues Before Increase			$9,824,911
Proposed Revenue Increase			710,452
Total Revenue Requirement			10,535,363
Less:			
Proposed Basic Service Charge Revenues			4,369,671
Projected Base Fuel			1,976,916
Winter Rate > 750 - differential	($0.03000)	26,634,997 Kwh	(799,050)
Subtotal			5,547,537
Net to be Collected Through Energy			$4,987,826
Total Kwh			88,215,802
Summer Rate per Kwh			$0.05654
Winter Rate Per Kwh - 1st 750 Kwh			$0.05654
Winter Rate - Over 750 Kwh			$0.02654

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Irrigation Power Service Rate 25 - Settlement
Projected 2023

Irrigation Power Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge	49	$1.50	per day	$26,828	$1.90	per day	$33,982
Energy	1,577,312	$0.00186	per Kwh	2,934	$0.00126	per Kwh	1,987
Generation Rider				2,950			
Total Energy				5,884			1,987
Demand							
Summer	6,464.3	$4.25	per KW	27,473	$4.88	per KW	31,546
Winter	3,576.3	1.25	per KW	4,470	1.88	per KW	6,723
Total Demand				31,943			38,269
Base Fuel	1,577,312	$0.02241	per Kwh	$35,348	$0.02241	per Kwh	$35,348
Total Revenue				$100,003			$109,586

Total Revenues Per Design	$109,586
Target Revenues	109,594
Difference	$8

Derivation of Rate:

Projected Revenues Before Increase	$100,003
Proposed Revenue Increase	9,591
Total Revenue Requirement	109,594
Less:	
Proposed Basic Service Charge Revenues	33,982
Proposed Demand Charge Revenues	38,269
Projected Base Fuel	35,348
Subtotal	107,599
Net to be Collected Through Energy	1,995
Total Kwh Sales	1,577,312
Proposed Energy Charge	$0.00126

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Small General Optional Time-of-Day Electric Service Rate 26 - Settlement
Projected 2023

Small General Optional TOD Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge	270	$1.00	per day	$98,550	$1.25	per day	$123,188
Energy							
Summer							
On-Peak Kwh	164,452	$0.06066	per Kwh	9,976	$0.05746	per Kwh	9,449
Off Peak Kwh	495,677	0.03566	per Kwh	17,676	0.03246	per Kwh	16,090
Subtotal	660,129			27,652			25,539
Winter							
On-Peak Kwh	313,159	$0.04566	per Kwh	14,299	$0.04246	per Kwh	13,297
Off Peak Kwh	977,269	0.02066	per Kwh	20,190	0.01746	per Kwh	17,063
Subtotal	1,290,428			34,489			30,360
Generation Rider				3,648			
Total Energy	1,950,557			65,789			55,899
Base Fuel	1,950,557	$0.02241	per Kwh	43,712	$0.02241	per Kwh	43,712
Total Rate 26 Revenues				$208,051			$222,799
Total Revenues Per Design							$222,799
Target Revenues							222,806
Difference							($7)

Derivation of Rate:

Projected Revenues Before Increase				$208,051
Proposed Revenue Increase				14,755
Total Revenue Requirement				222,806
Proposed Basic Service Charge Revenues				123,188
Projected Base Fuel				43,712
Winter Differential	($0.01500)	1,290,428	Kwh	(19,356)
On-Peak Differential	$0.02500	477,611	Kwh	11,940
				159,484
Net to be Collected Through Energy				$63,322
Total On-Peak Kwh				1,950,557
Summer Off-Peak Rate				$0.03246
Summer On-Peak Rate				$0.05746
Winter Off-Peak Rate				$0.01746
Winter On-Peak Rate				$0.04246

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Large General Electric Service Rate 30 - Settlement
Projected 2023

Large General Service 30	Billing Determinants	Projected @ Current Rates Rate	Projected @ Current Rates Revenue	Proposed Rates Rate	Proposed Rates Revenue
Basic Service Charge					
Primary Service Rate 30	40	$100.00 per month	$48,000	$108.03 per month	$51,854
Secondary Service Rate 30	4,566	56.00 per month	3,068,352	58.72 per month	3,217,386
Rate 95 - single phase, no instrument	1	0.05 per day	18	0.05 per day	18
Rate 95 - single phase, instrument	2	0.19 per day	139	0.19 per day	139
Rate 95 - three phase, instrument	4	0.33 per day	482	0.33 per day	482
Total Customers	4,613		3,116,991		3,269,879
Energy					
Primary Service - Rate 30	226,484,074	$0.01414 per Kwh	3,202,465	$0.01538 per Kwh	3,483,325
Subtotal	226,484,074		3,202,465		3,483,325
Secondary Service - Rate 30	722,746,179	$0.02331 per Kwh	16,847,213	$0.02444 per Kwh	17,663,917
Subtotal	722,746,179		16,847,213		17,663,917
Total Energy	949,230,253		20,049,698		21,147,242
Demand					
Primary Service - Summer	173,353.0	$14.00 per Kw	2,426,942	$15.05 per Kw	2,608,963
Primary Service - Winter	333,742.6	11.00 per Kw	3,671,169	12.05 per Kw	4,021,598
Generation Rider			279,973		
Subtotal	507,095.6		6,378,084		6,630,561
Secondary Service - Summer	774,698.9	$12.50 per Kw	9,683,736	$13.01 per Kw	10,078,833
Secondary Service - Winter	1,428,215.4	9.50 per Kw	13,568,046	10.01 per Kw	14,296,436
Generation Rider			1,216,251		
Subtotal	2,202,914.3		24,468,033		24,375,269
Total Demand	2,710,009.9		30,846,117		31,005,830
Base Fuel					
Primary Service- Rate 30	226,484,074	$0.02179 per Kwh	4,935,088	$0.02179 per Kwh	4,935,088
Secondary Service- Rate 30	722,746,179	0.02241 per Kwh	16,196,742	0.02241 per Kwh	16,196,742
Total Base Fuel	949,230,253		21,131,830		21,131,830
Total Rate 30 Revenue			$75,144,636		$76,654,781
Total Revenues Per Design					
Primary- Rate 30					$15,100,828
Secondary - Rate 30					61,453,314
Total					76,554,142
Target Revenues					76,551,526
Difference					$2,616

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Large General Electric Service Rate 30 - Settlement
Projected 2023

Large General Service 30	Current Rates Allocation	Proposed Settlement	Proposed Rates			
Basic Service Charge						
Primary Service Rate 30	0.51%	51,652	108.03			
Secondary Service Rate 30	7.11%	3,217,412	56.72			
Rate 95 - single phase, no instrument	0.00%	0				
Rate 95 - single phase, instrument	0.00%	0				
Rate 95 - three phase, instrument	0.00%	0				
Total Customers						
Energy						
Primary Service - Rate 30	34.26%	3,483,256	0.01536			
Subtotal						
Secondary Service - Rate 30	39.03%	17,661,830	0.02444			
Subtotal						
Total Energy						
Demand						
Primary Service - Summer						
Primary Service - Winter						
Generation Rider						
Subtotal	65.23%	6,632,017	Summer Differential	3.00	173,353	520,059
			Remaining to be collected			6,111,958
			Winter Demand		507,096	12.05
Secondary Service - Summer			Summer Demand			15.05
Secondary Service - Winter						
Generation Rider						
Subtotal	53.86%	24,372,688	Summer Differential	3.00	774,699	2,324,097
			Remaining to be collected			22,048,591
Total Demand			Winter Demand		2,202,914	10.01
			Summer Demand			13.01
Base Fuel						
Primary Service- Rate 30						
Secondary Service- Rate 30						
Total Base Fuel	100.00%	10,167,127	Primary			
	100.00%	45,251,930	Secondary			
Total Rate 30 Revenue		55,419,057				
Total Revenues Per Design						
Primary- Rate 30	$52,516,943	55,419,057				
Secondary - Rate 30						
Total						
Target Revenues						
Difference						

Secondary	Current		Proposed	
Customer	3,068,352	7.11%	3,217,386	7.11%
Demand	23,251,762	53.86%	24,375,269	53.86%
Energy	16,847,213	39.03%	17,663,917	39.03%
	43,167,347	100.00%	45,256,572	100.00%

Primary	Current		Proposed	
Customer	48,000	0.51%	51,654	0.51%
Demand	6,098,111	65.23%	6,630,561	65.22%
Energy	3,202,485	34.26%	3,483,325	34.27%
	9,348,596	100.00%	10,165,740	100.00%

	Rev per Design	Proj Revenues
Primary	15,100,828	15,102,215
Secondary	61,453,953	61,449,311
	76,554,781	76,551,526

	Current Rate	Total Rev Req
Primary	9,348,596	10,167,127
Secondary	43,167,347	45,251,930
	52,515,943	55,419,057

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Large Time-of-Day Electric Service Rate 31 - Settlement
Projected 2023

Large General TOD Service (Rate 31)	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge							
Primary Service	1	$97.00	per month	$1,164	$97.00	per month	$1,164
Secondary Service	52	72.00	per month	44,928	72.00	per month	44,928
Total Base Rate	53			46,092			46,092
Energy							
Primary Service							
Off-Peak	1,826,200	$0.01357	per Kwh	24,768	$0.01544	per Kwh	28,181
On-Peak	652,800	0.01607	per Kwh	10,490	0.01794	per Kwh	11,711
Total Energy	2,478,000			35,258			39,892
Primary Subtotal	2,478,000			35,258			39,892
Secondary Service							
Off-Peak	9,987,672	$0.02262	per Kwh	225,921	$0.02449	per Kwh	244,598
On-Peak	3,865,623	0.02512	per Kwh	97,104	0.02699	per Kwh	104,333
Total Energy	13,853,295			323,025			348,931
Secondary Subtotal	13,853,295			323,025			348,931
Total Energy	16,331,295			358,283			388,823
Demand							
Summer Primary Service							
Off-Peak	0.0	$0.00	per KW	0	$0.00	per Kw	0
On-Peak	1,761.1	15.25	per KW	26,857	15.57	per Kw	27,420
Total Summer Demand	1,761.1			26,857			27,420
Winter Primary Service							
Off-Peak	0.0	$0.00	per KW	0	$0.00	per Kw	0
On-Peak	3,108.5	12.25	per KW	38,079	12.57	per Kw	39,074
	3,108.5			38,079			39,074
Generation Rider				2,689			-
Primary Subtotal	4,869.6			67,625			66,494
Summer Secondary Service							
Off-Peak	0.0	$0.00	per KW	0	$0.00	per Kw	0
On-Peak	14,134.0	14.75	per KW	208,477	15.04	per Kw	212,575
Total Summer Demand	14,134.0			208,477			212,575
Winter Secondary Service							
Off-Peak	0.0	$0.00	per KW	0	$0.00	per Kw	0
On-Peak	24,706.3	10.75	per KW	265,593	11.04	per Kw	272,758
	24,706.3			265,593			272,758
Generation Rider				21,444			-
Secondary Subtotal	38,840.3			495,514			485,333
Total Demand	43,709.9			563,139			551,827
Base Fuel							
Primary	2,478,000	$0.02179	per Kwh	53,996	$0.02179	per Kwh	53,996
Secondary	13,853,295	0.02241	per Kwh	310,452	0.02241	per Kwh	310,452
Total Rate 31 Revenue				$1,331,962			$1,351,190
Total Revenues Per Design							
Primary- Rate 31							$161,546
Secondary - Rate 31							1,189,644
							1,351,190
Target Revenues							1,351,143
Difference							$47

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Large Time-of-Day Electric Service Rate 31 - Settlement
Projected 2023

Derivation of Rate:

Projected Revenues Before Increase				$1,331,962
Proposed Revenue Increase				19,181
Total Revenue Requirement				1,351,143
Less:				
Proposed Basic Service Charge Revenues				46,092
Proposed Demand Revenues				551,827
Secondary Energy Differential	$0.00905	13,853,295	Kwh	125,372
On-Peak Energy Differential	0.00250	4,518,423	Kwh	11,296
Projected Base Fuel				364,448
Subtotal				1,099,035
Net to be Collected Through Energy				$252,108
Total Kwh Sales				16,331,295
Proposed Energy Charges:				
Primary Off-Peak				$0.01544
Primary On-Peak				$0.01794
Secondary Off-Peak				$0.02449
Secondary On-Peak				$0.02699

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
General Space Hearting Electric Service Rate 32 - Settlement
Projected 2023

General Space Heating Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge							
Primary Service	0	$21.00	per month	$0	$23.00	per month	$0
Secondary Service	603	21.00	per month	151,956	23.00	per month	166,428
Total Base Rate	603			151,956			166,428
Energy							
Primary Service	0	$0.01422	per Kwh	0	$0.01569	per Kwh	0
Riders				0			
Subtotal	0			0			0
Secondary Service	57,227,301	$0.02422	per Kwh	1,386,045	$0.02569	per Kwh	1,470,169
Generation Rider							
Subtotal	57,227,301			1,386,045			1,470,169
Total Energy	57,227,301			1,386,045			1,470,169
Demand							
Primary Service - Summer	0.0	$14.00	per Kw	0	$15.05	per Kw	0
Primary Service - Winter	0.0	1.00	per Kw	0	1.38	per Kw	0
Riders				0			
Subtotal	0.0			0			0
Secondary Service - Summer	39,291.9	$12.50	per Kw	491,149	$13.01	per Kw	511,188
Secondary Service - Winter	231,145.8	1.00	per Kw	231,146	1.38	per Kw	318,981
Generation Rider				65,470			
Subtotal	270,437.7			787,765			830,169
Total Demand	270,437.7			787,765			830,169
Base Fuel							
Primary Service	0	$0.02179	per Kwh	0	$0.02179	per Kwh	0
Secondary Service	57,227,301	0.02241	per Kwh	1,282,464	0.02241	per Kwh	1,282,464
Total Base Fuel	57,227,301			1,282,464			1,282,464
Total Rate 32 Revenue				$3,608,230			$3,749,230
Total Revenues Per Design							
Secondary							3,749,230
Total							3,749,230
Target Revenue							3,749,878
Difference							($648)

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
General Space Hearting Electric Service Rate 32 - Settlement
Projected 2023

Derivation of Rate:

Projected Revenues Before Increase	$3,608,230
Proposed Revenue Increase	141,648
Total Revenue Requirement	3,749,878
Less:	
Proposed Basic Service Charge Revenues	
Secondary Service	166,428
Proposed Summer Demand Revenues	
Secondary Service	511,188
Secondary Energy	1,470,169
Projected Base Fuel	1,282,464
Subtotal	3,430,249
Net to be Collected Through Secondary Deman	$319,629
Total Winter Demand	231,146
Proposed Energy Charges:	
Winter - Primary & Secondary	$1.38

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Interruptible Large Power Demand Response Rate 38 - Settlement
Projected 2023

Large Demand Response	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge	4		Per Contract	$7,140	$108.03	per month	$5,185
Energy	31,986,100	$0.01252	per Kwh	400,466	$0.01344	per Kwh	429,893
Demand							
Summer	34,757.1	$11.00	per KW	382,328	$11.55	per KW	401,445
Winter	69,417.6	8.00	per KW	555,340	8.55	per KW	593,520
Generation Rider				57,516			
Total Demand	104,174.7			995,184			994,965
Base Fuel	31,986,100	$0.02179	per Kwh	696,977	$0.02179	per Kwh	696,977
Total Rate 38 Revenue				$2,099,767			$2,127,020
Total Revenues Per Design							$2,127,020
Target Revenues							2,127,064
Difference							($44)

Derivation of Rate:

Projected Revenues Before Increase	$2,099,767
Proposed Revenue Increase	27,297
Total Revenue Requirement	2,127,064
Less:	
Proposed Basic Service Charge Revenues	5,185
Proposed Demand Revenues	994,965
Projected Base Fuel	696,977
Subtotal	1,697,127
Net to be Collected Through Energy	$429,937
Total Kwh Sales	31,986,100
Proposed Energy Charge	$0.01344

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Municipal Service Rate 40 - Settlement
Projected 2023

Small Municipal Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge							
Non-Demand	233	$0.84	per day	$71,438	$1.15	per day	$97,748
Demand	38	1.00	per day	13,870	1.30	per day	18,031
Total Base Rate	271			85,308			115,779
Energy							
Non-Demand Service							
Summer	393,049	$0.03402	per Kwh	13,372	$0.03365	per Kwh	13,226
Winter							
First 750 Kwh	629,155	$0.03402	per Kwh	21,404	$0.03365	per Kwh	21,171
Over 750 Kwh	588,879	0.02302	per Kwh	13,556	0.02265	per Kwh	13,338
Subtotal	1,218,034			34,960			34,509
Demand Service	1,659,753	$0.01302	per Kwh	21,610	$0.01265	per Kwh	20,996
Generation Rider				6,117			
Total Energy	3,270,836			76,059			68,731
Demand							
Summer	2,700.6	$11.25	per Kw	30,382	$12.93	per Kw	34,919
Winter							
1st 10 Kw	2,556.1	$0.00	per Kw	$0	$0.00	per Kw	0
Over 10 Kw	1,964.2	8.25	per Kw	16,205	9.93	per Kw	19,505
	4,520.3			16,205			19,505
Total Demand	7,220.9			46,587			54,424
Base Fuel							
Non-Demand Service	1,611,083	$0.02241	per Kwh	36,104	$0.02241	per Kwh	36,104
Demand Service	1,659,753	0.02241	per Kwh	37,195	0.02241	per Kwh	37,195
Total Base Fuel	3,270,836			73,299			73,299
Total Rate 40 Revenue	3,270,836			$281,253			$312,233
Total Revenues Per Design							
Non-Demand Service							$181,587
Demand Service							130,646
Total							312,233
Target Revenues							312,239
Difference							($6)

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Municipal Service Rate 40 - Settlement
Projected 2023

Derivation of Rate:

Projected Revenues Before Increase				$281,253
Proposed Revenue Increase				30,986
Total Revenue Requirement				$312,239
Less:				
Proposed Basic Service Charge Revenues				115,779
Proposed Demand Revenues				54,424
Summer- 1st 750 Winter Differential	($0.01100)	588,879	Kwh	(6,478)
Non-Demand Energy Differential	$0.02100	1,611,083	Kwh	33,833
Projected Base Fuel				73,299
Subtotal				270,857
Net to be Collected Through Energy				$41,382
Total Kwh Sales				3,270,836
Proposed Energy Charges:				
Demand Service				$0.01265
Non-Demand Rate:				
Winter - 1st 750				$0.03365
Winter - Over 750				0.02265
Summer				$0.03365

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Municipal Lighting Service Rate 41 - Settlement
Projected 2023

Municipal Lighting Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge							
Primary	0	$0.00	per month	$0	$0.00	per month	$0
Secondary	0	0.00	per month	0	0.00	per month	0
Energy							
Primary	1,174,555	$0.05096	per Kwh	59,855	$0.05180	per Kwh	60,842
Generation Rider				975			0
Secondary	12,133,777	0.05596	per Kwh	679,006	0.05680	per Kwh	689,199
Generation Rider				10,178			0
Total Energy	13,308,332			750,014			750,041
Base Fuel							
Primary	1,174,555	$0.02179	per Kwh	25,594	$0.02179	per Kwh	25,594
Secondary	12,133,777	0.02241	per Kwh	271,918	0.02241	per Kwh	271,918
Total Base Fuel	13,308,332			297,512			297,512
Discount @ 10% - Excluding Base Fuel							
Primary	1,174,555			(5,990)			
Secondary	10,946,620			(61,301)			-
Total Discount	12,121,175			(67,291)			0
Total Rate 41 Revenue				$980,235			$1,047,553
Total Revenues Per Design							$1,047,553
Target Revenues							1,047,526
Difference							$27

Derivation of Rate:

Projected Revenues Before Increase			$980,235
Proposed Revenue Increase			67,291
Total Revenue Requirement			1,047,526
Less:			
Proposed Basic Serivce Charge Revenues			0
Secondary Differential	$0.0050	12,133,777 Kwh	60,669
Projected Base Fuel			297,512
Subtotal			358,181
Net to be Collected Through Energy			$689,345
Total Kwh Sales			13,308,332
Proposed Energy Charges:			
Primary			$0.05180
Secondary			0.05680

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Municipal Pumping Service Rate 48 - Settlement
Projected 2023

Municipal Pumping Service	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge							
Primary	5	$80.00	per month	$4,800	$80.00	per month	$4,800
Secondary	303	45.00	per month	163,620	45.00	per month	163,620
Excess Facilities Charge	1			2,330			2,330
Total Basic Service Charge				170,750			170,750
Energy							
Primary	23,520,600	$0.01798	per Kwh	422,900	$0.01394	per Kwh	327,877
Riders				0			
Secondary	22,345,983	0.01898	per Kwh	424,127	0.01494	per Kwh	333,849
Riders				0			
Total Energy	45,866,583			847,027			661,726
Demand							
Summer							
Primary	20,780.4	$9.00	per KW	187,024	$12.00	per KW	249,365
Secondary	29,257.8	9.00	per KW	263,320	12.00	per KW	351,094
Subtotal	50,038.2			450,344			600,459
Winter							
Primary	30,215.0	$6.00	per KW	181,290	$9.00	per KW	271,935
Secondary	54,427.1	6.00	per KW	326,563	9.00	per KW	489,844
Subtotal	84,642.1			507,853			761,779
Generation Rider- Primary				25,340			
Generation Rider- Secondary				42,323			
Total Demand	134,680.3			1,025,860			1,362,238
Base Fuel							
Primary	23,520,600	$0.02179	per Kwh	512,514	$0.02179	per Kwh	512,514
Secondary	22,345,983	0.02241	per Kwh	500,773	0.02241	per Kwh	500,773
Subtotal	45,866,583			1,013,287			1,013,287
Primary Discounted (all accounts)				(79,649)			(85,398)
Secondary Discounted							
Bills	248			(13,392)			(13,392)
Energy	18,922,797			(35,954)			(28,271)
Demand - Summer	24,690.2			(22,220)			(29,628)
Demand - Winter	45,599.2			(27,360)			(41,039)
Total Discounted				(178,575)			(197,728)
Total Rate 48 Revenue				$2,878,349			$3,010,273
Total Revenues Per Design							
Primary							$1,366,491
Secondary							1,643,782
							$3,010,273
Target Revenues							3,010,407
Difference							($134)

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Municipal Pumping Service Rate 48 - Settlement
Projected 2023

Derivation of Rate:

Projected Revenues Before Increase			$2,878,349
Proposed Revenue Increase			132,058
Total Revenue Requirement			3,010,407
Less:			
Proposed Basic Service Charge Revenues			156,878
Proposed Demand Revenues			1,239,441
Secondary Differential	$0.00100	20,453,703 Kwh	20,454
Projected Base Fuel			1,013,287
Subtotal			2,430,060
Net to be Collected Through Energy			$580,347
Total Kwh Sales			41,622,243
Primary Energy Rate			$0.01394
Secondary Energy Rate			$0.01494

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Outdoor Lighting Service Rate 52 - Settlement
Projected 2023

	Billing	Projected @ Current Rates			Proposed Rates		
Outdoor Lighting	Determinants	Rate		Revenue	Rate		Revenue
Basic Service Charge	0	$0.00	per month	$0	$0.00	per month	$0
Energy							
Primary Service	34,081	$0.06357	per Kwh	2,167	$0.06578	per Kwh	2,242
Generation Rider				31			0
Secondary Service	3,958,084	0.06763	per Kwh	267,685	0.06984	per Kwh	276,433
Generation Rider				3,641			0
Total Energy	3,992,165			273,524			278,675
Base Fuel							
Primary Service	34,081	$0.02179	per Kwh	743	$0.02179	per Kwh	743
Secondary Service	3,958,084	0.02241	per Kwh	88,701	0.02241	per Kwh	88,701
Total Base Fuel	3,992,165			89,444			89,444
Total Revenue				$362,968			$368,119
Total Revenues Per Design							$368,119
Target Revenues							368,132
Difference							($13)

Derivation of Rate:

Projected Revenues Before Increase				$362,968
Proposed Revenue Increase				5,164
Total Revenue Requirement				$368,132
Less:				
Secondary Energy Differential	$0.00406	3,958,084	Kwh	16,070
Projected Base Fuel				89,444
Subtotal				105,514
Net to be Collected Through Energy				262,618
Total Kwh Sales				3,992,165
Proposed Energy Charge				
Primary				$0.06578
Secondary				$0.06984

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Contract Rate 304 - Settlement
Projected 2023

Contract Rate 304	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge	1	$100.00	per month	$1,200	$108.03	per month	$1,296
Energy							
First 2.3 Million Kwh	26,032,640	$0.01669	per Kwh	434,485	$0.01879	per Kwh	489,153
Over 2.3 Million Kwh	1,135,200	0.01144	per Kwh	12,987	0.01354	per Kwh	15,371
	27,167,840			447,472			504,524
Demand							
Summer							
First 5,000 Kw	18,126.8	$8.58	per KW	155,528	$9.06	per KW	164,229
Over 5,000 Kw	0.0	5.72	per KW	0	6.04	per KW	0
Winter							
First 5,000 Kw	37,098.1	$5.72	per KW	212,201	$6.04	per KW	224,073
Over 5,000 Kw	0.0	5.72	per KW	0	6.04	per KW	0
Generation Rider				30,490			0
				398,219			388,302
Base Fuel	27,167,840	0.02179	per Kwh	591,987	0.02179	per Kwh	591,987
Total Contract Revenues				$1,438,878			$1,486,109
Total Revenues Per Design							$1,486,109
Target Revenues							1,486,094
							15

Derivation of Rate:

Net Increase to Contracts	5.59%		
Projected Revenues Before Increase			$1,438,878
Proposed Revenue Increase			47,216
Total Revenue Requirement			1,486,094
Less:			
Proposed Basic Service Charge Revenues			$1,296
Proposed Demand Revenues			388,302
Over 2.3 Million Energy Differential	($0.00525)	1,135,200	(5,960)
Proposed Base Fuel			591,987
			975,625
Net to be Collected Through Energy Charge			$510,469
Total Kwh Sales		27,167,840	
Proposed Energy Charges			
First 2.3 million			$0.01879
Over 2.3 million			$0.01354

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Derivation of Rate and Reconciliation
Contract Rate 303 - Settlement
Projected 2023

Contract Rate 303 & 302	Billing Determinants	Projected @ Current Rates Rate		Projected @ Current Rates Revenue	Proposed Rates Rate		Proposed Rates Revenue
Basic Service Charge	1	$100.00	per month	$1,200	$108.03	per month	$1,296
Energy							
First 1.5 Million Kwh	18,000,000	$0.02148	per Kwh	386,640	$0.02333	per Kwh	419,940
Over 1.5 Million Kwh	80,750,754	0.01472	per Kwh	1,188,651	0.01657	per Kwh	1,338,040
Total Energy	98,750,754			1,575,291			1,757,980
Demand							
Summer	57,085.5	$8.56	per KW	488,652	$9.04	per KW	516,053
Winter	104,431.8	5.44	per KW	568,109	5.74	per KW	599,439
Generation Rider				89,175			0
Total Demand	161,517.3			1,145,936			1,115,492
Base Fuel	98,750,754	$0.02179	per Kwh	2,151,779	$0.02179	per Kwh	2,151,779
Total Contract Revenues				$4,874,206			$5,026,547
Target Revenues Per Design							$5,026,547
Target Revenues							5,026,183
							$364

Derivation of Rate:

Net Increase to Contracts	5.59%		
Projected Revenues Before Increase			$4,874,206
Proposed Revenue Increase			151,977
Total Revenue Requirement			5,026,183
Less:			
Proposed Basic Service Charge Revenues			1,296
Proposed Demand Revenues			1,115,492
Over 1.5 Million Kwh Energy Differential	($0.00676)	80,750,754	(545,875)
Proposed Base Fuel			2,151,779
			2,722,692
Net to be Collected Through Energy Charge			$2,303,491
Total Kwh Sales		98,750,754	
Proposed Energy Charges			
First 1.5 Million Kwh			$0.02333
Over 1.5 Million Kwh			$0.01657

MONTANA-DAKOTA UTILITIES CO.
BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
CASE NO. PU-23-___
PREPARED DIRECT TESTIMONY OF
ANN E. BULKLEY

Q1. Please state your name and business address.

A1. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q2. On whose behalf are you submitting this testimony?

A2. I am submitting this direct testimony before the North Dakota Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. My testimony addresses the regulated gas utility operations of Montana-Dakota Utilities Co. in North Dakota ("Montana-Dakota" or the "Company").

Q3. Please describe your education and experience.

A3. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a listing of the testimony that I have filed in other proceedings as Exhibit No.___(AEB-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q4. Please describe the purpose of your testimony.

A4. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate return on equity ("ROE") for the Company and to assess the reasonableness of its proposed capital structure used for ratemaking purposes.

Q5. Are you sponsoring any schedules in support of your Direct Testimony?

A5. Yes. My analysis and recommendations are supported by the data presented in Exhibit No. ___(AEB-2), Schedules 2 through 13, which were prepared by me or under my direction.

Q6. Please provide a brief overview of the analyses that led to your ROE recommendation.

A6. I have estimated the cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration: (1) the Company's small size relative to the proxy group; (2) flotation costs; (3) the Company's anticipated capital expenditure requirements; and (4) the Company's regulatory risk as compared with the proxy group. Finally, I considered the Company's capital structure as compared with the capital structures of the proxy companies. While I do not make specific adjustments to my ROE recommendation for these factors, I did consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q7. How is the remainder of your testimony organized?

A7. The remainder of my testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions the cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my cost of equity estimates and the analytical basis for my recommendation of the appropriate ROE for Montana-Dakota.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section VIII provides an assessment of the reasonableness of the Company's proposed capital structure relative to the proxy group.
- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSES AND CONCLUSIONS

Q8. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A8. In developing my recommended ROE for Montana-Dakota, I considered the following:

- The United States Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

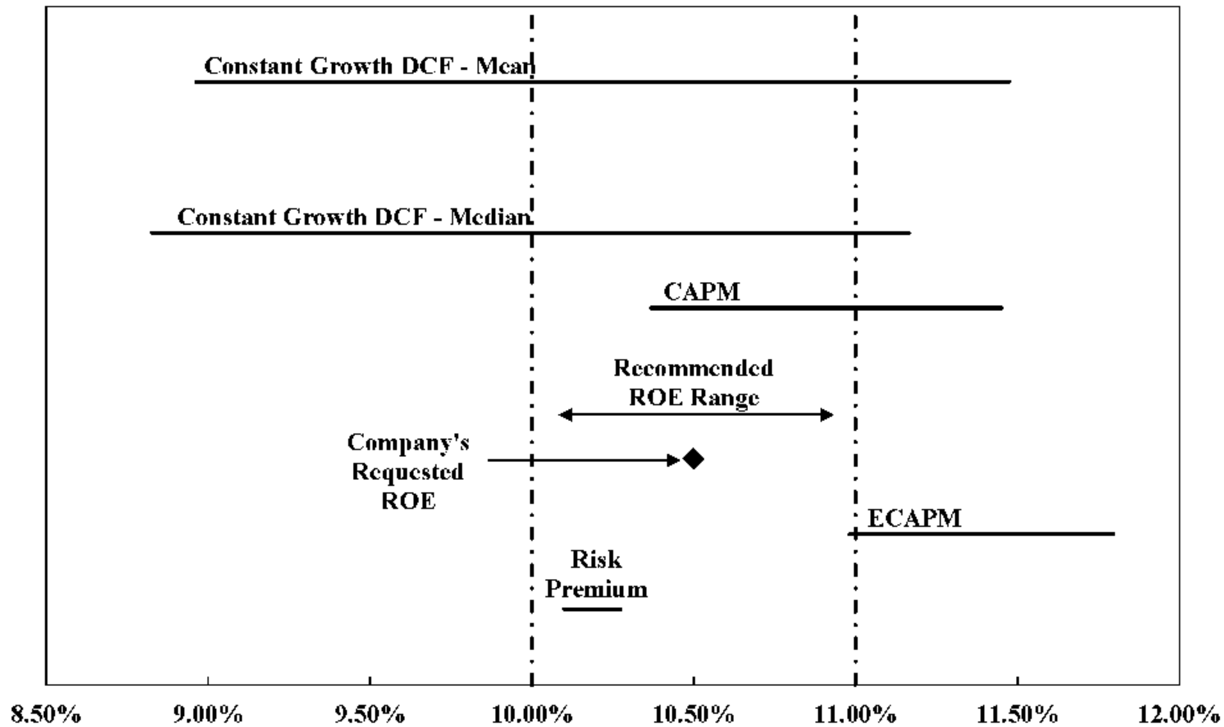
- The effect of current and projected capital market conditions on cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to Montana-Dakota, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q9. What are the results of the models that you have used to estimate the cost of equity for Montana-Dakota?

A9. Figure 1 summarizes the range of results produced by the constant growth DCF, CAPM, ECAPM, and Bond Yield Risk Premium analyses.[2]

[2] Exhibit No. ___(AEB-2), Schedule 2.

Figure 1: Summary of Cost of Equity Model Results



As shown in Figure 1 (and Exhibit No. ___(AEB-2), Schedule 2), the range of results produced by the cost of equity estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Q10. Are prospective capital market conditions expected to affect the results of the COE for the Company during the period in which the rates established in this proceeding will be in effect?

A10. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.

- Long-term interest rates have increased substantially in the past year and are expected to remain elevated at least over the next year in response to inflation.
- Since utility dividend yields are now less attractive than the risk-free rates of government bonds, and interest rates are expected to remain near current levels over the next year, it is likely that utility share prices will decline.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the near-term.
- Consequently, the results of the DCF model, which relies on current utility share prices, may understate the cost of equity during the period that the Company's rates will be in effect.
- Rating agencies have cited increased risk in the utility sector due to increased interest rates, inflation and elevated capital expenditures.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for the Company.

Q11. What is your recommended ROE for Montana-Dakota in this proceeding?

A11. Considering the analytical results presented in Figure 1, current and prospective capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.00 percent to 11.00 percent is reasonable. Within my recommended range, the Company is requesting an ROE of 10.50 percent which is conservative considering the relative business and financial risk of Montana-Dakota to the proxy group and current and prospective market conditions.

Q12. Is the Company's requested capital structure reasonable?

A12. Yes. The Company's proposed equity ratio of 50.185 percent is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies. Further, the Company's proposed equity ratio is reasonable considering the credit rating agencies concerns regarding the negative effect on the cash flows and credit metrics associated with increasing interest rates, inflation and capital expenditures.

III. REGULATORY GUIDELINES

Q13. Please describe the guiding principles to be used in establishing the cost of equity for a regulated utility.

A13. The United States Supreme Court's precedent-setting *Hope and Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[3]

Q14. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A14. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable natural gas service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost.

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[3] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

Q15. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A15. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other electric, natural gas, and water utilities can inhibit the utility's ability to attract capital for investment.

While Montana-Dakota is committed to investing the required capital to provide safe and reliable service, because Montana-Dakota is a subsidiary of MDU Resources, the Company competes with the other MDU Resources subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for MDU Resources to consider the authorized ROE of each of its subsidiaries.

Q16. Is the regulatory framework and the authorized ROE and equity ratio important to the financial community?

A16. Yes. The regulatory framework is one of the most important factors in debt and equity investors' assessments of risk. Specifically regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing, they also act as a signal to equity investors about the risk of investing in the equity of a company.

Q17. What is the standard for setting the ROE in any jurisdiction?

A17. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for the Montana-Dakota's natural gas operations in North Dakota.

Q18. What are your conclusions regarding regulatory guidelines?

A18. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q19. Why is it important to analyze capital market conditions?

A19. The models used to estimate the cost of equity rely on market data that are specific either to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the cost of equity estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses both current and projected market data, specifically stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE and the recommended ROE for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q20. What factors affect the cost of equity for regulated utilities in the current and prospective capital markets?

A20. The cost of equity for regulated utility companies is affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) relatively high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

Q21. What effect do current and prospective market conditions have on the cost of equity for Montana-Dakota?

A21. As discussed in more detail in the remainder of this section, the combination of persistently high inflation and the Federal Reserve's changes in monetary policy contribute to an expectation of an increase in the cost of the investor-required return. It is essential that these factors be considered in setting the forward-looking ROE. Inflation has recently been at some of the highest levels seen in approximately 40 years, and while inflation has declined from these recent peaks, it remains relatively high. Interest rates, which have increased significantly from pandemic-related lows seen in 2020, are expected to continue to remain relatively high in direct response to the Federal Reserve's use of monetary policy to combat inflation. These market conditions are indicative of an increase in the cost of equity since (i) there is a strong historical inverse correlation between interest rates (i.e., yields on long-term government bonds) and the share prices of utility stocks (i.e., as interest rates increase, utility share prices decline, and thus utility dividend yields increase); and (ii) the yields on long-term government bonds currently exceed the dividend yields of utilities, and historically long-term government bond yields have been lower than the dividend yields of utilities. Because the cost of equity in this proceeding is being estimated for the future period that the Company's rates will be in effect, and because the cost of equity is expected to increase over the near term for utilities, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, will likely understate the cost of equity during the future period that the Company's rates will be in effect.

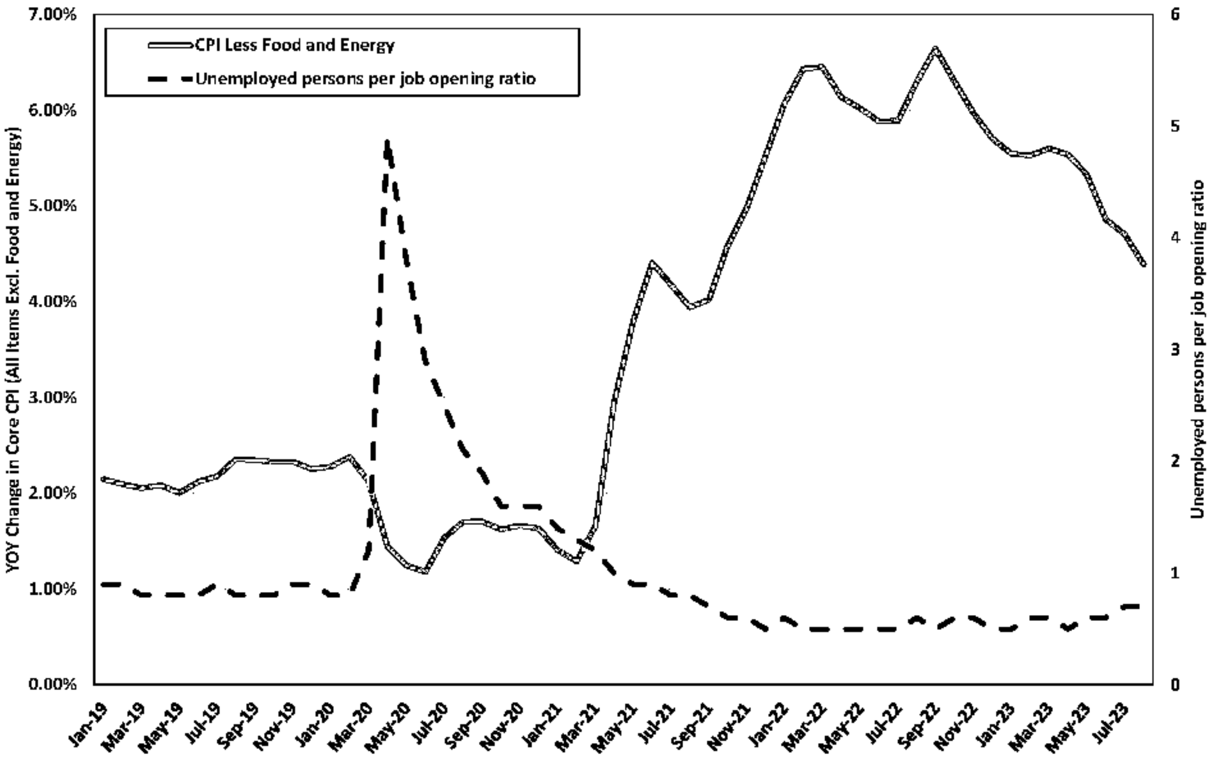
A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q22. Has inflation increased significantly over the past year?

A22. Yes. Figure 2 presents the year-over-year ("YOY") change in core inflation as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve since it removes the effect of food and energy prices, which can be highly volatile. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982. Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, core inflation continues to remain above the Federal Reserve's target level of 2.0 percent.

Finally, as shown in Figure 2, I also considered the ratio of unemployed persons per job opening which is currently 0.7 and has been consistently below 1.0 since 2021 despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to August 2023[4]



Q23. What are the expectations for inflation over the near-term?

A23. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level over at least the next year and that monetary policy will remain restrictive in order to reduce inflation. For example, Federal Reserve Chair Powell at the Federal Open Market Committee ("FOMC") meeting in September 2023 observed that while inflation is off of its recent highs, it remains significantly above the Federal Reserve's long-term target:

> Inflation remains well above our longer-run goal of 2 percent. Based on the Consumer Price Index and other data, we estimate that total PCE [personal consumption expenditures] prices rose 3.4 percent over the 12 months

4 Bureau of Labor Statistics.

> ending in August; and that, excluding the volatile food and energy categories, core PCE prices rose 3.9 percent. Inflation has moderated somewhat since the middle of last year, and longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. Nevertheless, the process of getting inflation sustainably down to 2 percent has a long way to go. The median projection in the SEP for total PCE inflation is 3.3 percent this year, falls to 2.5 percent next year, and reaches 2 percent in 2026.[5]

As a result, Federal Reserve Chair Powell noted that they intend to maintain a restrictive policy stance until substantial progress has been made to reduce inflation to the long-term target of 2 percent.[6] Moreover, the Federal Reserve is currently forecasting an additional 25 basis point increase in the federal funds rate in 2023.[7] Given the expectation that monetary policy will remain restrictive, as noted previously, yields on long-term government bonds are expected to remain elevated over the near-term.

B. The Use of Monetary Policy to Address Inflation

Q24. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A24. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Since the March 2022 meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25 percent to a range of 5.25 percent to 5.50 percent.[8]

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5 Federal Reserve, Transcript of Chair Powell's Press Conference, September 20, 2023, p 2.

6 *Id.*, at 3.

7 Federal Reserve, Summary of Economic Projections, September 20, 2023, at 2.

8 Federal Reserve, Press Releases, March 16, 2022, May 4, 2022, June 15, 2022, September 22, 2022, November 2, 2022, February 1, 2023, March 22, 2023, May 3, 2023, July 26, 2023. Federal Reserve Board - Press Releases

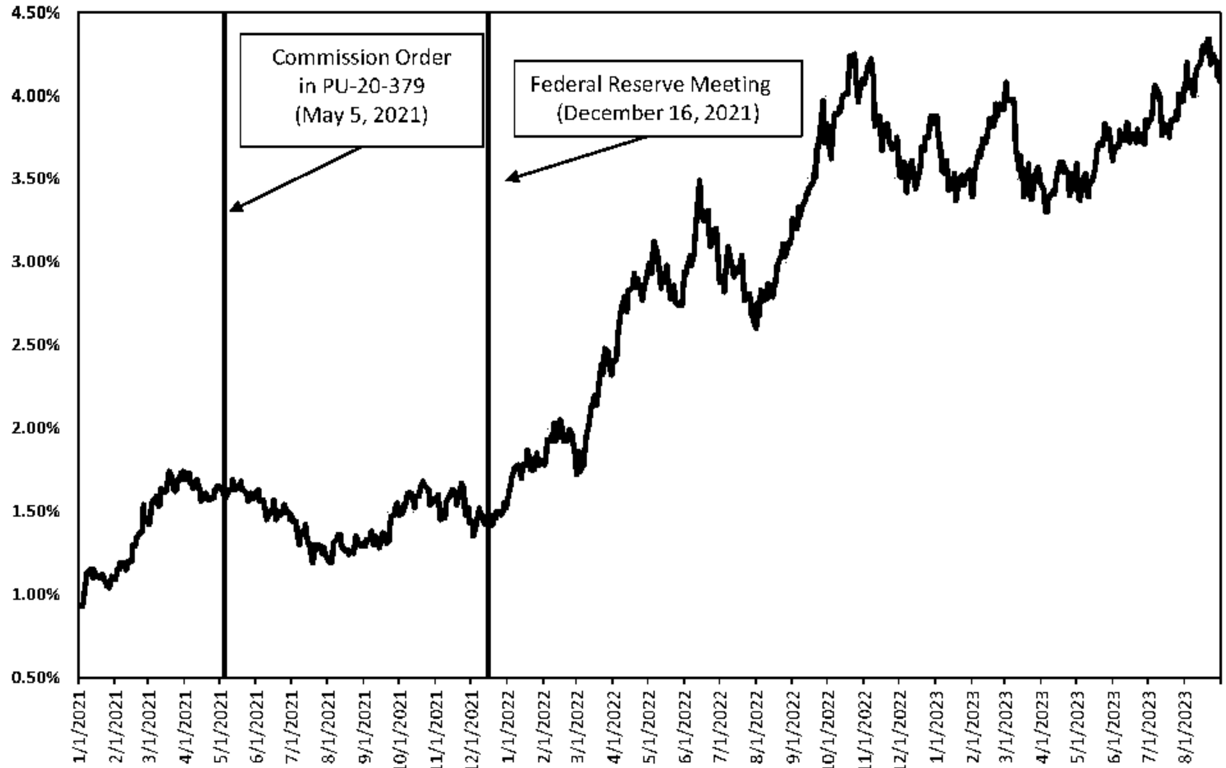
Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q25. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A25. Yes. As the Federal Reserve has substantially increased the federal funds rate and decreased its holdings of Treasury bonds and mortgage-backed securities in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rates have also increased. As shown in Figure 3 below, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has more than doubled, increasing from 1.47 percent on December 15, 2021 to 4.09 percent at the end of August 2023. Further, since the Commission's order that approved the settlement agreement in the Company's last rate proceeding (Case No. PU-20-379) in May 2021, the 30-day average yield on the 10-year Treasury bond has increased from 1.64 percent to 4.11 percent, or 247 basis points.

Figure 3: 10-Year Treasury Bond Yield—Janaury 2021through August 31, 2023[9]



Q26. What have equity analysts said about long-term government bond yields?

A26. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated through at least the first quarter of 2025. According to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yield on the 10-year Treasury bond is approximately 3.80 percent through the first quarter of 2025.[10] It is reasonable to expect that if government bond yields remain elevated, the cost of equity will be increasing above the levels experienced in the 2020 and 2021 lower interest rate environment.

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[9] S&P Capital IQ Pro.

[10] *Blue Chip Financial Forecasts*, Vol. 42, No. 9, September 1, 2023.

Q27. How have interest rates and inflation changed since the Company's last rate case?

A27. As shown in Figure 4, when the Commission approved the settlement agreement authorizing an ROE of 9.30 percent in the Company's 2020 rate proceeding, interest rates (as measured by the 30-year Treasury bond yield) were 2.31 percent and core inflation was 3.80 percent. However, since the Company's 2020 rate proceeding, long-term interest rates have increased by approximately 190 basis points as the Federal Reserve has increased the federal funds rate to combat inflation, which, as shown, is also higher than during the Company's last rate case, and, as noted, remains above the Federal Reserve's target.

Figure 4: Change in Market Conditions Since Montana-Dakota's Last Rate Case[11]

Docket	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate	Auth'd ROE
C-PU-20-379	5/5/2021	0.06%	2.31%	3.80%	9.30%
Current	8/31/2023	5.33%	4.21%	4.39%	

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q28. Are utility share prices correlated to changes in the yields on long-term government bonds?

A28. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman

[11] St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[12]

Q29. How do equity analysts expect the utility sector to perform in an increasing interest rate environment?

A29. Equity analysts project that utilities will underperform the broader market given the increases in interest rates. Fidelity classifies the utility sector as underweight,[13] and Bank of American recently noted that they are "not so constructive on [u]tilities" given that the dividend yields for utilities are below both the yields available on long- and short-term treasury bonds.[14]

Q30. Why do equity analysts expect the utility sector to underperform over the near-term?

A30. While interest rates have increased substantially over the past year, the valuations of utilities have not fully reflected the effect of the recent increase in interest rates. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through August 2023 ("yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds. As shown in Figure 5, the recent significant increase in long-term government bonds yields has resulted in the yield on long-

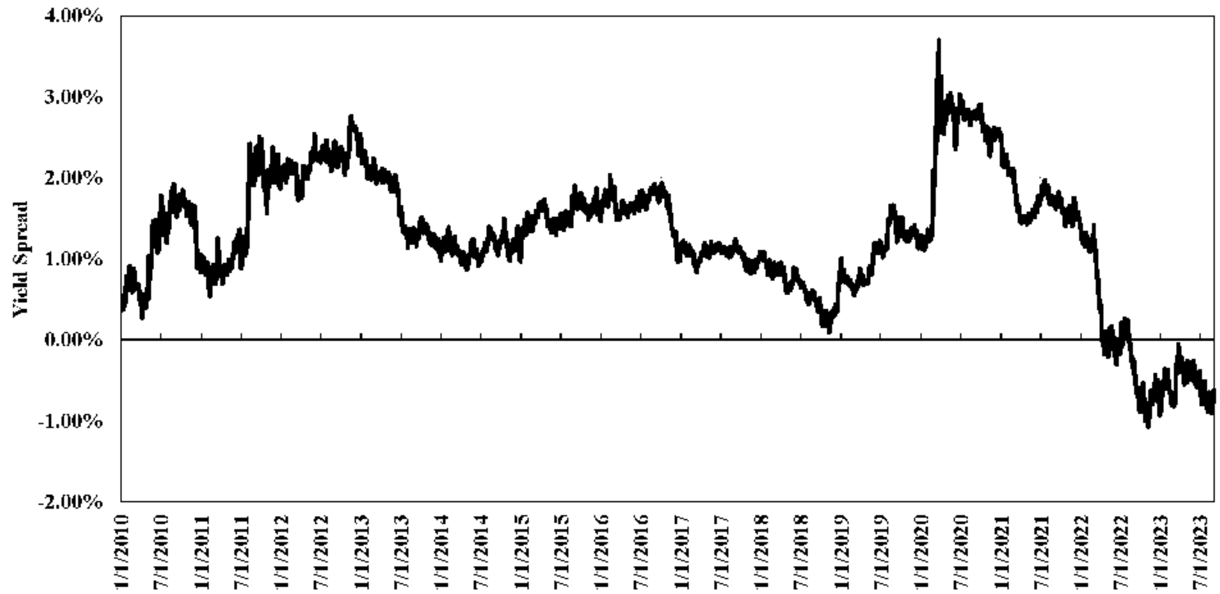
[12] Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, March 11, 2021.

[13] Fidelity. "Third Quarter 2023 Investment Research Update." July 24, 2023.

[14] Dumoulin-Smith, "US Electric Utilities & IPPs: As the leaves fall, preparing for Autumn utility outlook. Macro still has potholes," September 6, 2023.

term government bonds exceeding the dividend yields of utilities. The yield spread as of August 31, 2023 was negative 0.62 percent. However, the long-term average yield spread from 2010 to 2023 is 1.27 percent. Therefore, the current yield spread is well below the long-term average. Because of the fact that the yield spread is currently well below the long-term average, and the expectation that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – August 2023[15]



Q31. Do you have any further context as to how unlikely it is to have a negative yield spread of this magnitude?

A31. Yes. For further context as to how unlikely it is to have a yield spread of negative 0.62 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread of negative 0.62 percent has a z-score of -2.32, a yield spread of negative 0.62 percent is over 2 standard deviations from the mean of 1.27 percent.[16] In other words, 95 percent of the daily yield spread observations from 2010 through August 2023 fall between -0.36 percent and 2.91 percent, with the current yield spread of negative 0.62 percent being outside of that range. Thus,

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[15] S&P Capital IQ Pro and Bloomberg Professional.

[16] The z-score is calculated as: (yield spread at August 31, 2023 minus average yield spread 2010 through August 2023)/standard deviation of yield spread from 2010 through August 2023. This equals: (-0.0062 minus 0.0127)/0.0082.

the current yield spread is an outlier, which is why equity analysts do not expect this current level to hold.

Q32. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A32. If interest rates remain relatively high as expected, then the share prices of utilities would be expected to decline. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices to calculate the dividend yield, is likely to understate the dividend yield and thus the cost of equity.

E. Conclusion

Q33. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A33. Investors expect long-term interest rates to remain relatively high through 2024 in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and government bond yields are already greater than utility stock dividend yields, the share prices of utilities are likely to continue to decline, which is the reason a number of equity analysts have classified the sector as either underperform or underweight. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

V. PROXY GROUP SELECTION

Q34. Please provide a brief profile of Montana-Dakota.

A34. Montana-Dakota Utilities Co. is a wholly-owned subsidiary of MDU Resources Group, Inc. ("MDU"). MDU provides natural gas distribution service across eight states through the Company, including its division Great Plains Natural Gas Co., and its affiliates Cascade Natural Gas Corp. and Intermountain Gas Company. In total, MDU serves approximately 1.03 million natural gas customers. Specifically, the Company provides service to approximately 115,521 natural gas customers in North Dakota[17], and the Company's North Dakota natural gas operations accounted for approximately 16 percent of MDU's total retail gas sales revenue in 2022.[18] The Company also provides vertically-integrated electric utility service in South Dakota, North Dakota, Montana, and Wyoming, serving approximately 144,500 customers. Montana-Dakota Utilities Co. currently has an investment-grade long-term rating of BBB+ (Outlook: Developing) from S&P[19] and BBB+ (Outlook: Stable) from Fitch.[20]

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[17] Montana-Dakota Utilities, 2022 Annual Report to the North Dakota Public Service Commission, IV. Miscellaneous, Line No. 6.

[18] MDU Resources Group, Inc. Form 10-K for the fiscal year ended December 31,2022, at 15.

[19] Source: S&P Capital IQ Pro, (accessed September 28, 2023).

[20] Source: FitchRatings, (accessed September 28, 2023).

Q35. Why have you used a group of proxy companies to estimate the cost of equity for the Company?

A35. One of the purposes of this proceeding is to estimate the cost of equity for a utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and Montana-Dakota's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

Even if Montana-Dakota was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate cost of equity for the Company.

Q36. How did you select the companies included in your proxy group?

A36. I began with the group of 10 publicly traded companies that Value Line classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends that have not been reduced in the last three years, since companies that do not pay dividends cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;

- derive more than 70.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from gas distribution operations; and,
- were not party to a merger or transformative transaction during the analytical period considered or had a material event that would have affected the market data for the company.

I developed the screens and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size against establishing a proxy group of companies that are comparable in business and financial risk to the Company.

Q37. What is the composition of your proxy group?

A37. The screening criteria discussed above is shown in Exhibit No. ___(AEB-2), Schedule 3, and resulted in a proxy group consisting of the companies shown Figure 6 below.

Figure 6: Natural Gas Utility Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
NiSource	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

VI. COST OF EQUITY ESTIMATION

Q38. Please briefly discuss the ROE in the context of the regulated rate of return.

A38. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. The ROE is the cost of common equity capital in the utility's capital structure for ratemaking purposes. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q39. How is the required cost of equity determined?

A39. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q40. What methods did you use to establish your recommended ROE in this proceeding?

A40. I considered the results of the constant growth DCF model, the CAPM, the ECAPM, and the BYRP analyses. As discussed in more detail below, a reasonable cost of equity estimate considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q41. Is it important to use more than one analytical approach to estimate the cost of equity?

A41. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and we use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[21] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[22] recommend the CAPM, DCF, and BYRP approaches.

Q42. Do current market conditions increase the importance of using more than one analytical approach?

A42. Yes. As discussed previously, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. While the share prices of utilities have declined, the negative yield spread noted above is an indication that the share prices have not declined sufficiently to account for the recent rise in interest rates. As a result, equity analysts expect the utility sector to continue to underperform over the next year. Given the expected underperformance, it is reasonable to conclude that the DCF model is likely understating the forward-looking cost of equity because the model relies on historical share prices. The

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21 Copeland, Tom, Tim Koller and Jack Murrin. Valuation: Measuring and Managing the Value of Companies. New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

22 Brigham, Eugene and Louis Gapenski. Financial Management: Theory and Practice. Orlando, Dryden Press, 1994, at 341.

CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses offer some balance through the use of interest rates as a direct input into the models and therefore may better reflect the market conditions expected when the Company's rates are in effect. These recent changes in market conditions highlight the benefit of using multiple models since each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. It is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

B. Constant Growth DCF Model

Q43. Please describe the DCF approach.

A43. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q44. What assumptions are required for the constant growth DCF model?

A44. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q45. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A45. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended August 31, 2023.

Q46. Why did you use 30-, 90-, and 180-day averaging periods?

A46. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q47. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A47. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q48. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A48. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the constant growth DCF model.

Q49. Which sources of long-term earnings growth rates did you use?

A49. My constant growth DCF model incorporates three sources of long-term earnings per share ("EPS") growth rates: (1) Zacks Investment Research ("Zacks"); (2) Yahoo! Finance; and (3) Value Line.

Q50. Why are EPS growth rates the appropriate growth rates to be relied on in the DCF model?

A50. Earnings are the fundamental driver of a company's ability to pay dividends; therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.

Q51. How did you calculate the range of results for the constant growth DCF models?

A51. I calculated the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the Zacks, Yahoo! Finance, and Value Line projected earnings growth rates) for each of the proxy group companies. I used a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculated results using the average growth rate from all three sources for each proxy group company.

Q52. What were the results of your constant growth DCF analyses?

A52. Figure 7 (see also Exhibit No. ___(AEB-2), Schedule 4) summarizes the results of my DCF analyses. As shown, the mean/median DCF results using the average growth rates range from 9.86 percent to 10.12 percent, and the mean/median results using the maximum growth rates range from 10.97 percent to 11.56 percent. While I also summarize the mean DCF results using the minimum growth rates, given the expected underperformance of utility stocks and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider these DCF results at this time.

Figure 7: Constant Growth Discounted Cash Flow Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.05%	10.12%	11.56%
90-Day Avg. Stock Price	8.95%	10.02%	11.47%
180-Day Avg. Stock Price	8.89%	9.96%	11.40%
Average	8.96%	10.03%	11.47%
Median Results:			
30-Day Avg. Stock Price	9.04%	9.86%	11.35%
90-Day Avg. Stock Price	8.81%	9.90%	11.18%
180-Day Avg. Stock Price	8.63%	9.95%	10.97%
Average	8.83%	9.90%	11.16%

Q53. Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of relatively high inflation and elevated interest rates?

A53. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission ("PPUC") concluded that the current capital market conditions of high inflation and increased interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided

> by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[23]
>
> . . . . .
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[24]

More recently, the Massachusetts Department of Public Utilities ("MDPU") also recently came to a similar conclusion:

> The Department recently considered the relationship between low interest rates and utility stock prices over the last several years and whether a projected increase in long-term interest rates caused the DCF analysis to understate the cost of equity. D.P.U. 20-120, at 416-419. The Department found that, although utility stocks had increased above historic levels in conjunction with low interest rates, the evidence in that proceeding that long-term interest rates would change was speculative. D.P.U. 20-120, at 417-419. In this proceeding, the record is clear that long-term interest rates have increased compared to the period of time from which the parties derived the dividend yields used in the DCF analyses (Exh. ES-VVR-Rebutal-1, at 23-26; Tr. 14, at 1463). We also have considered the Attorney General's evidence of investors forecasting that utility stocks will retain

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[23] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

[24] *Id.*, pp. 177–178.

> their high valuations in the near term (Tr. 14, at 1449-1452; RR-DPU-48). ***Based on the foregoing evidence, the Department finds that there is greater certainty that the DCF results understate the Company's cost of equity.***[25]

Q54. What are your conclusions about the results of the DCF models?

A54. As discussed previously, one primary assumption of the DCF model is a constant price-to-earnings ratio, and that assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates remain elevated and yields on long-term government bonds exceed utility dividend yields, it is important to consider the results of the DCF model with caution. Therefore, while I have given weight to the results of the DCF model, my recommendation also gives weight to the results of other cost of equity estimation models.

C. CAPM Analysis

Q55. Please briefly describe the CAPM.

A55. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable, systematic risk of that security. Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

The CAPM is defined by four components:

[25] The Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 22-22, Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, November 30, 2022, p. 385-386; emphasis added.

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market cost of equity;
β = beta coefficient of an individual security;
r_f = the risk-free rate of return; and
r_m = the required return on the market.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined a:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the Covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q56. What risk-free rate do you use in your CAPM analysis?

A56. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds, which is 4.21 percent;[26] (2) the average projected 30-year Treasury bond yield for the fourth quarter of 2023 through the fourth quarter of 2024, which

[26] Bloomberg Professional as of August 31, 2023.

is 4.04 percent;[27] and (3) the average projected 30-year Treasury bond yield for 2025 through 2029, which is 3.80 percent.[28]

Q57. What beta coefficients do you use in your CAPM analysis?

A57. As shown Exhibit No. ___(AEB-2), Schedule 5, I use the beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The beta coefficients reported by Bloomberg are calculated using ten years of weekly returns relative to the S&P 500 Index. The Value Line beta coefficients are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Additionally, as shown in shown Exhibit No. ___(AEB-2), Schedule 5, I also consider an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group. As shown in Exhibit No. ___(AEB-2), Schedule 6, the long-term average utility Beta coefficient was calculated as an average of the Value Line beta coefficients for the companies in my proxy group from 2013 through 2022.

Q58. How do you estimate the market risk premium in the CAPM?

A58. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit No. ___(AEB-2), Schedule 7, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.61 percent and a weighted long-term growth rate of 11.13 percent, the estimated required market return for the S&P 500 Index

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27 *Blue Chip Financial Forecasts*, Vol. 42, No. 9, September 1, 2023, at 2.

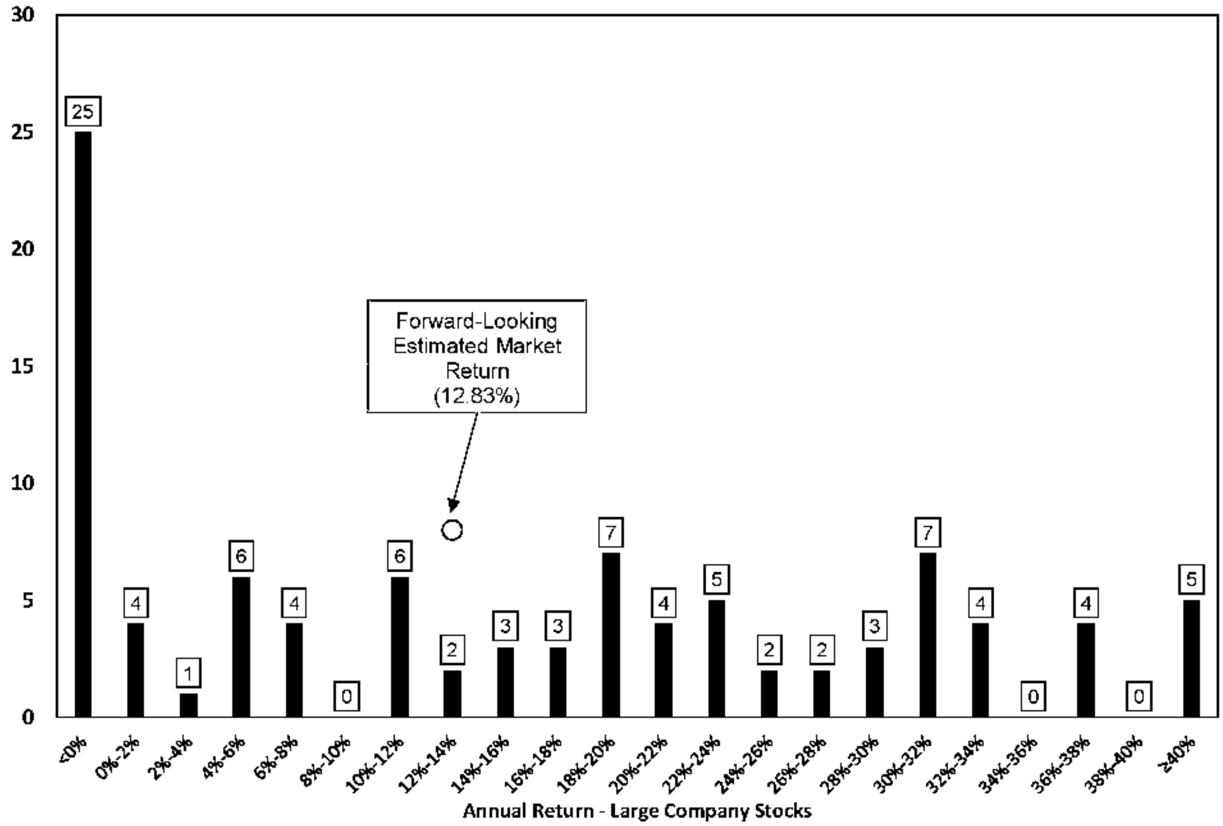
28 *Blue Chip Financial Forecasts*, Vol. 42, No. 6, June 1, 2023, at 14.

as of August 31, 2023 is 12.83 percent. As shown in Exhibit No. ___(AEB-2), Schedule 5, based on the three risk-free rates considered, the market risk premium ranges from 8.62 percent to 9.03 percent.

Q59. How does the current expected market return compare to observed historical market returns?

A59. As shown in Figure 8, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.83 percent is not unreasonable. In 50 out of the past 97 years (or approximately 52 percent of observations), the realized equity market return was at least 12.83 percent or greater.

Figure 8: Realized U.S. equity market returns (1926-2022)[29]



Q60. Did you consider another form of the CAPM in your analysis?

A60. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[30] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

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[29] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook.

[30] *See, e.g.*, Morin, Roger A. New Regulatory Finance. Public Utilities Reports, Inc., 2006, at 189.

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:
k_e – the required market cost of equity;
β – Adjusted beta coefficient of an individual security;
rf – the risk-free rate of return; and
r_m = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[31]

Consistent with my CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the current Bloomberg, current Value Line, and long-term Value Line beta coefficients.

Q61. What are the results of your CAPM analyses?

A61. As shown in Figure 9 (see also Exhibit No. ___(AEB-2), Schedule 5), my traditional CAPM analysis produces a range of returns from 10.37 percent to 11.45 percent. The ECAPM analysis results range from 10.98 percent to 11.80 percent.

[31] *Id.* at 191.

Figure 9: CAPM and ECAPM Results

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current Value Line Beta	11.45%	11.42%	11.39%
Current Bloomberg Beta	10.78%	10.74%	10.68%
Long-term Avg. Value Line Beta	10.48%	10.43%	10.37%
ECAPM:			
Current Value Line Beta	11.80%	11.78%	11.75%
Current Bloomberg Beta	11.29%	11.26%	11.22%
Long-term Avg. Value Line Beta	11.07%	11.03%	10.98%

D. BYRP Analysis

Q62. Please describe the BYRP analysis.

A62. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

Q63. What is the fundamental relationship between the equity risk premium and interest rates?

A63. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis provided in Exhibit No. ___(AEB-2), Schedule 8 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the yield on the long-term Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[32]

Q64. Is the BYRP analysis relevant to investors?

A64. Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

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[32] *See e.g.*, Berry, S. Keith. "Interest Rate Risk and Utility Risk Premia during 1982-93." Managerial and Decision Economics, Vol. 19, No. 2, March, 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Harris, Robert S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management*, Spring 1986, at 66.

Q65. What did your BYRP analysis reveal?

A65. As shown in Figure 10, from 1992 through August 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs were derived from all natural gas utility rate cases from 1992 through August 2023 as reported by Regulatory Research Associates ("RRA").[33] This equation's coefficients were statistically significant at the 99.00 percent level.

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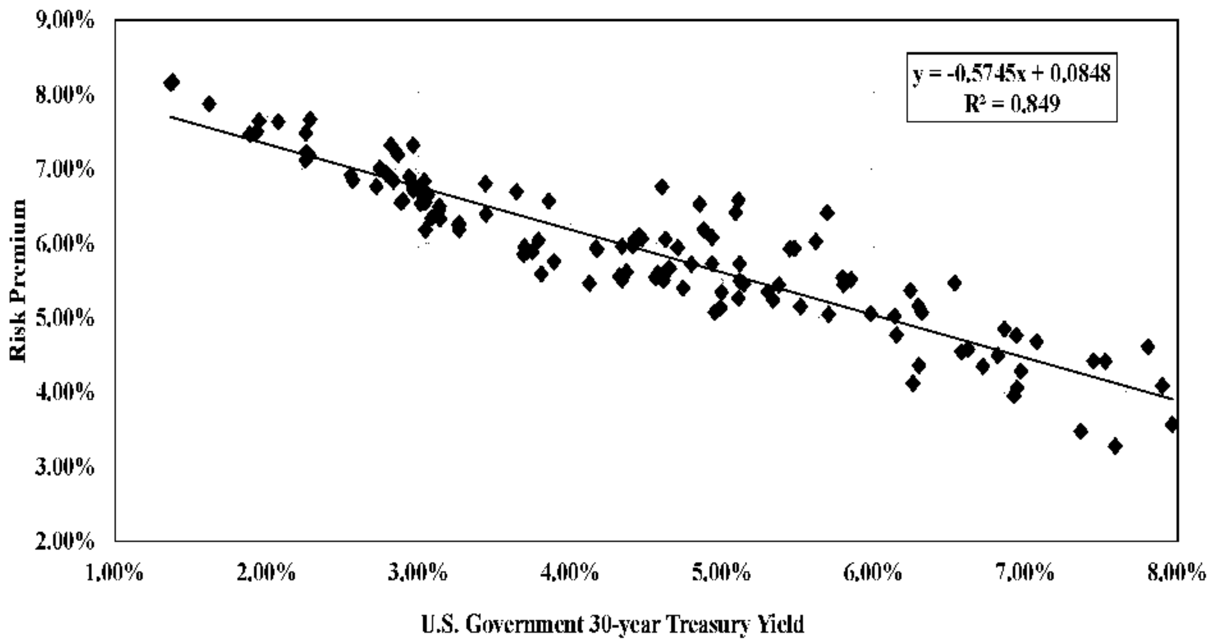
[33] This analysis was screened to eliminate limited issue rider cases, transmission cases and cases that were silent with respect to the authorized ROE.

Figure 10: Risk Premium Regression Analysis



Q66. What are the results of your BYRP analysis?

A66. The results of my BYRP analysis are shown in Figure 11 (and on Exhibit No. ___(AEB-2), Schedule 8).

Figure 11: Risk Premium Results

	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield	4.21%	6.06%	10.27%
Blue Chip Near-Term Projected Forecast (Q4 2023 - Q4 2024)	4.04%	6.16%	10.20%
Blue Chip Long-Term Projected Forecast (2025-2029)	3.80%	6.30%	10.10%
Average			10.19%

Q67. How did the results of the BYRP analysis inform your recommended ROE for the Company?

A67. I have considered the results of the BYRP analysis in setting my recommended ROE for Montana-Dakota's natural gas operations in North Dakota. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

VII. REGULATORY AND BUSINESS RISKS

Q68. Taken alone, do the results of the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Company?

A68. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Small Size Risk

Q69. Is there a risk to a firm associated with small size?

A69. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[34]

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[34] Annin, Michael. "Equity and the Small-Stock Effect." Public Utilities Fortnightly, October 15, 1995.

Q70. How does the smaller size of a utility affect its business risk?

A70. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q71. How do Montana-Dakota's natural gas operations in North Dakota compare in size to the proxy group companies?

A71. Montana-Dakota's natural gas operations in North Dakota are substantially smaller than the median for the proxy group companies in terms of market capitalization. While Montana-Dakota is not publicly traded on a stand-alone basis, as shown on Exhibit No. ___(AEB-2), Schedule 9, I have estimated the implied market capitalization for the Company (*i.e.*, the market capitalization if the Company were a stand-alone publicly-traded entity) relative to the actual market capitalization for the proxy group companies.

Specifically, to estimate the size of the Company's implied market capitalization relative to the proxy group, I first calculated the equity component of the Company's capital structure by multiplying the Company's test year rate base of $216.97 million by the Company's proposed common equity ratio in this proceeding of 50.185 percent. I then applied the median market-to-book ratio for the proxy group of 1.60 to the Company's implied common equity balance to estimate an implied market capitalization, which is approximately $174.15 million, or just 4.10 percent of the median market capitalization for the proxy group.

Q72. How did you estimate the size premium for Montana-Dakota?

A72. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[35] As shown on Exhibit No. ___(AEB-2), Schedule 9, the median market capitalization of the proxy group is approximately $4.25 billion, which corresponds to the fourth decile of *Kroll's* market capitalization data.[36] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.58 percent (*i.e.*, 58 basis points). In comparison, the Company's implied market capitalization of approximately $174.15 million falls within the 10th decile, which corresponds to a size premium of 4.83 percent (*i.e.*, 483 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 425 basis points (*i.e.*, 4.83 percent minus 0.58 percent)

Q73. Were utility companies included in the size premium study conducted by *Kroll*?

A73. Yes. As shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies

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[35] *Kroll* Cost of Capital Navigator – Size Premium; annual data as of December 31, 2022.

[36] *Id.*

contained in the fourth decile, which indicates that Kroll has included utility companies in its size risk premium study.[37]

Q74. Is the size premium applicable to companies in regulated industries such as utilities?

A74. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[38] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp (2003) showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[39]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[40] The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly

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[37] *Kroll*, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

[38] Zepp, Thomas M. "Utility Stocks and the Size Effect—Revisited." The Quarterly Review of Economics and Finance, Vol. 43, No. 3, 2003, at 578–582.

[39] *Id.*

[40] Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, Vol. 18, No. 2, 2011.

included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins (2011) show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[41]

Q75. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A75. Yes. For example, in Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk." [42] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[43] Similarly, the RCA has also noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[44] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the

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41 *Id.*

42 Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

43 *Id.*, at 32 and 37.

44 Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

> record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[45]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF results as a result of multiple factors, including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[46]

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[47]

Q76. How have you considered the smaller size of Montana-Dakota's natural gas distribution operations in North Dakota in your recommended ROE?

A76. While I have estimated the effect of the Company's small size of its natural gas operations in North Dakota on the cost of equity, I am not proposing a specific adjustment for this risk

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45 *Id.*

46 Minnesota Public Utilities Commission, Docket No. E017/GR-15-1033, Order, August 16, 2016, at 55.

47 *Ass'n. of Businesses Advocating Tariff Equity, et. al., v. Midcontinent Indep. Sys. Operator, Inc., et. al.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

factor. Rather, I believe it is important to consider the small size of the Company's utility operations in the determination of where, within the range of analytical results, Montana-Dakota's required cost of equity falls. All else equal, the additional risk associated with the Company's small size supports an ROE toward the upper end of the range of results from the cost of equity estimation models.

B. Flotation Cost

Q77. What are flotation costs?

A77. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q78. Why is it important to consider flotation costs in the authorized ROE?

A78. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q79. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A79. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation costs are incurred prior to the test year but remain part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny the Company the opportunity to earn its required rate of return in the future.

Q80. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A80. Assume MDU issues stock with a value of $100, and an equity investor invests $100 in MDU in exchange for that stock. Further, suppose that after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q81. Is the date of MDU's last issuance of common equity important in the determination of flotation costs?

A81. No. As shown in Exhibit No. ___(AEB-2), Schedule 10, MDU closed on equity issuances of approximately $58 million and $54 million (for a total of 4.7 million shares of common stock) in November 2002 and February 2004, respectively. However, it is important to recognize flotation costs for all equity issuances since these costs reduce the permanent capital structure of the company. Therefore, the vintage of the issuance is not particularly important because an investor should have a reasonable opportunity to earn a return on the full amount of capital that she has contributed in every year of the investment. As noted in my earlier example, the investor contributed $100, but due to flotation costs, MDU only ends up with $97 to invest in rate base. Without the recognition of flotation costs, the investor will only earn a return on the $97 invested in rate base in year 1 as well as every subsequent year of the investment. Therefore, adjusting the ROE in year 1 to recognize flotation costs will only award the opportunity for the investor to earn a return on her full investment in year 1 and then in year 2 and after the investor will still only earn a return on the $97 invested in rate base. As a result, the ROE should be adjusted for flotation costs in every year regardless of the vintage of the issuance because as long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q82. Is the need to consider flotation costs eliminated because Montana-Dakota is a wholly-owned subsidiary of MDU?

A82. No, it is not. Although the Company is a wholly-owned subsidiary of MDU, it is appropriate to consider flotation costs. Wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund utility operations and inhibits the utility's ability to obtain new equity capital at a reasonable cost. This is particularly important in the current circumstance given that the Company is planning significant capital expenditures in the near term.

Q83. Is the need to consider flotation costs recognized by the academic and financial communities?

A83. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[48]

Further, Dr. Myron Gordon recognized that the DCF model did not include the cost of floating a new stock issue and proposed a means for regulators to recognize these costs in his text on the subject.[49]

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[48] Pratt, Shannon P. Cost of Capital Estimation and Applications. Second Edition, at 220-21.

[49] Gordon, Myron, "The Cost of Capital to a Public Utility", 1974, pp. 164-166.

Q84. Have you estimated what a reasonable flotation cost adjustment would be for Montana-Dakota?

A84. Yes. My flotation cost is estimated on the costs of issuing equity that were incurred by MDU in its two most recent common equity issuances. As shown in Exhibit No. ___(AEB-2), Schedule 10, based on the flotation costs of those two issuances, the impact on the proxy group's cost of equity amounts to 10 basis points (i.e., 0.10 percent) based on the median and 15 basis points (i.e., 0.15 percent) based on the mean.

Q85. Do your final cost of equity model results include an adjustment for flotation cost recovery?

A85. No, I did not make an explicit adjustment for flotation costs to any of the quantitative results of my cost of equity models. Rather, I considered the incremental cost associated with stock issuance as part of my overall recommendations regarding the range of reasonable ROEs and ultimate recommended ROE.

C. Capital Expenditures

Q86. Please summarize the capital expenditure requirements for Montana-Dakota's natural gas distribution operations in North Dakota.

A86. As of December 31, 2022, the Company had net utility plant of approximately $214.24 million, and the Company currently projects capital expenditures for 2024 through 2028 of approximately $190.28 million.[50] Therefore, the Company's projected capital

[50] Data provided by the Company.

expenditures represent approximately 88.81 percent of its net utility plant as of December 31, 2022.

Q87. How is the Company's risk profile affected by its capital expenditure requirements?

A87. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q88. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A88. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those

> jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[51]

Therefore, to the extent that Montana-Dakota's rates do not permit the Company to recover its capital investments on a timely basis and provide a reasonable opportunity to earn its authorized return, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q89. How do Montana-Dakota's capital expenditure requirements compare to those of the proxy group companies?

A89. As shown in Exhibit No. ___(AEB-2), Schedule 11, I calculated the ratio of expected capital expenditures to net utility plant for the Company and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024 through 2028 by its total net utility plant as of December 31, 2022. As shown in Exhibit No. ___(AEB-2), Schedule 11, the Company's ratio of capital expenditures as a percentage of net utility plant is 88.81 percent, which is greater than the median for the proxy group companies of 63.30 percent. This result indicates a risk level for Montana-Dakota that is higher than the proxy group companies.

Q90. Does Montana-Dakota have a capital tracking mechanism to recover the costs associated with its capital expenditures between rate cases?

A90. No. Montana-Dakota currently has not requested approval to recover capital investment costs between rate cases utilizing a capital tracking mechanism. The Company is proposing the use of a forecast test year ending December 31, 2024. As a result of the future test year,

[51] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

the Company will be able to recover its projected capital expenditures for 2024 in the rates that are determined in this proceeding. Therefore, the Company will still rely on future rate case filings for its capital expenditures plan for 2025-2028. However, significant programs like Montana-Dakota's that drive capital expenditure requirements generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit No. ___(AEB-2), Schedule 12, 71.4 percent of the companies in the proxy group have some form of capital cost recovery mechanisms in place. While the Company is proposing a forecast test year, Montana-Dakota does not currently have a capital tracking mechanism to recover capital cost between rate cases and as a result the Company's risk relative to the proxy group is increased.

Q91. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A91. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, unlike a number of the operating subsidiaries of the proxy group, Montana-Dakota does not have a comprehensive capital tracking mechanism to recover the Company's projected capital expenditures. Therefore, Montana-Dakota's capital expenditures plan and limited ability to recover the capital investment on an as incurred basis results in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

D. Regulatory Risk

Q92. How does the regulatory environment affect investors' risk assessments?

A92. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the subject utility must have the opportunity to recover invested capital and the market-required return on such capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, which balances the long-term interests of investors and customers. In that respect, the regulatory framework in which a utility operates is one of the most important factors considered in both debt and equity investors' risk assessments.

Because investors have many investment alternatives, even within a given market sector, the Company's authorized returns must be adequate on a relative basis to ensure their ability to attract capital under a variety of economic and financial market conditions. From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet their near-term financial obligations, make the capital investments needed to maintain and expand their systems, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also from efficient access to capital markets.

From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (that is, debt interest must be paid prior to any equity dividends), equity investors are particularly concerned with the regulatory framework in which a utility operates and its effect on future earnings and cash flows.

Q93. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A93. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[52]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[53] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[54]

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[52] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

[53] Standard & Poor's Global Ratings, Ratings Direct, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 2.

[54] *Id.*

Q94. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A94. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[55] Moody's has further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[56]

Q95. Have you conducted an analysis to compare the cost recovery mechanisms of Montana-Dakota to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?

A95. Yes. I have evaluated the regulatory framework in North Dakota on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (i.e., forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence

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[55] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.

[56] *Id.*

of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit No. ___(AEB-2), Schedule 12 and are summarized as follows:

<u>Test Year Convention</u>: Montana-Dakota is relying on a fully forecasted test year in North Dakota for the period January 1, 2024 through December 31, 2024. Similarly, approximately 52.4 percent of the operating utility subsidiaries of the proxy group companies provide service in jurisdictions that use a forecasted test year.

<u>Volumetric Risk:</u> Montana-Dakota currently has some protection against volumetric risk in North Dakota through straight fixed-variable rates for the residential rate class and a weather normalization clause known as the Distribution Delivery Stabilization Mechanism ("DDSM") for its firm general service rate class. However, the Company is not proposing to continue the use of straight fixed-variable rates for the residential rate class and instead is proposing the use of the DDSM for both its firm general service and residential classes. Approximately, approximately 91 percent of the utility operating subsidiaries of the proxy group companies have some form of protection against volumetric risk either through formula rates plans, revenue decoupling or straight fixed-variable rate design.

<u>Capital Cost Recovery</u>: As noted, while the Company is proposing a forecast test year which will allow the Company to recover a portion of its capital expenditures plan from 2024 through 2028, the Company does not have a capital tracking mechanism to recover capital investment costs between rate cases. However, approximately 71 percent of the operating utility subsidiaries of the proxy group companies have some form of capital cost recovery allowing for the recovery of capital investments placed into service between rate cases.

Q96. What is the effect on Montana-Dakota of having relatively fewer timely cost recovery mechanisms?

A96. The lack of timely cost recovery mechanisms can result in regulatory lag. Regulatory lag occurs when a regulated utility is not able to recover its just and reasonable costs of providing service to customers on a timely basis. Regulatory lag is reflected in a utility's financial performance through earnings attrition, which is the inability of the utility to earn its authorized ROE due to delays in the recovery of allowable costs that have been incurred to provide regulated service to customers.

Q97. Is there evidence that Montana-Dakota has been unable to earn its authorized ROE?

A97. Yes. As shown in Figure 12, Montana-Dakota's natural gas operations in North Dakota has significantly under-earned its authorized ROE in seven out of eight years since 2015. Over this period, the average earned ROE on the Company's natural gas operations in North Dakota was 7.55 percent, as compared with the average authorized ROE of 9.60 percent, for an average under-earning of 205 basis points per year. This under-earning occurred despite the fact that Montana-Dakota relied on a forecast test year and had partial protection of volumetric risk through straight fixed-variable rate design for the residential rate class and a weather normalization clause for its firm general service rate class.

Figure 12: Montana-Dakota's Earned vs. Authorized ROE (2015-2022)

	EARNED ROE	AUTHORIZED ROE	EARNINGS DIFFERENTIAL (BPS)
2015	8.09%	10.00%	-191
2016	7.74%	10.00%	-226
2017	6.62%	10.00%	-338
2018	9.44%	9.40%	4
2019	6.39%	9.40%	-301
2020	6.48%	9.40%	-292
2021	9.12%	9.30%	-18
2022	6.50%	9.30%	-280
Average	**7.55%**	**9.60%**	**-205**

Q98. What is your conclusion regarding the regulatory framework in North Dakota as compared with the jurisdictions in which the proxy group companies operate?

A98. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have more timely cost recovery through forecasted test years, capital cost recovery trackers and revenue stabilization mechanisms than Montana-Dakota has in North Dakota. Moreover, the Company has under-earned its authorized ROE in seven out of eight years since 2015. As a result, I conclude that the Company has greater than average regulatory risk when compared to the proxy group.

VIII. CAPITAL STRUCTURE

Q99. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A99. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as Montana-Dakota. All else equal, a higher debt ratio increases the risk to equity investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow available for common equity holders. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q100. What is Montana-Dakota's proposed capital structure?

A100. The Company is proposing to establish a capital structure consisting of 50.185 percent common equity, 45.296 percent long-term debt and 4.519 percent short-term debt.

Q101. Did you conduct an analysis to assess the reasonableness of the requested equity ratio?

A101. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. Since the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the average capital structure for the proxy group to benchmark the equity ratios for the Company.

Specifically, I calculated the average proportion of common equity, long-term debt, preferred equity and short-term debt for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown on Exhibit No. ___(AEB-2), Schedule 13, the average common equity ratio for the operating subsidiaries of the proxy group companies ranged from 44.57 percent to 59.79 percent, with an average of 53.59 percent. Given that Montana-Dakota's proposed equity ratio of 50.185 percent is within the range of equity ratios for the utility operating subsidiaries of the proxy group companies, I consider its proposed equity ratio to be reasonable.

Q102. Are there other factors to be considered in setting the Company's capital structure?

A102. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the outlook for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics, noting that constructive regulatory outcomes that promote timely cost recovery are a key factor in supporting utility credit quality.[57]

Fitch Ratings ("Fitch") also highlights similar factors identified by Moody's as challenging utilities' outlook for 2023, stating that the sector faces mounting cost pressures due to "elevated commodity prices, inflationary headwinds and rising interest costs," and that

[57] Moody's Investors Service, Outlook, "Outlook turns stable on low natural gas prices and credit-supportive regulation," September 7, 2023.

there are some offsets in managing these headwinds that include but not limited to higher authorized ROEs.[58]

Likewise, while S&P recently revised its outlook for the industry from negative to stable, S&P continues to see significant risks over the near-term for the industry as a result of inflation and increased levels of capital spending. Specifically, S&P noted:

> Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.[59]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for Montana-Dakota in the context of this proceeding

IX. CONCLUSIONS AND RECOMMENDATION

Q103. What is your conclusion regarding a fair ROE for the Company?

A103. Based on the various quantitative analyses summarized in Figure 13 and the qualitative analyses presented in my Direct Testimony, a reasonable range of ROE results for

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[58] Fitch Ratings. "North American Utilities, Power & Gas Outlook 2023." December 7, 2022, at 1-2.

[59] S&P Global Ratings. "The Outlook for North American Regulated Utilities Turns Stable." May 18, 2023, at 8.

Montana-Dakota is from 10.00 percent to 11.00 percent. Within that range, the Company is requesting an ROE of 10.50 percent which is conservative considering the business and financial risk of Montana-Dakota as compared to the proxy group as well as current and prospective capital market conditions.

Figure 13: Summary of Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.05%	10.12%	11.56%
90-Day Avg. Stock Price	8.95%	10.02%	11.47%
180-Day Avg. Stock Price	8.89%	9.96%	11.40%
Average	8.96%	10.03%	11.47%
Median Results:			
30-Day Avg. Stock Price	9.04%	9.86%	11.35%
90-Day Avg. Stock Price	8.81%	9.90%	11.18%
180-Day Avg. Stock Price	8.63%	9.95%	10.97%
Average	8.83%	9.90%	11.16%

CAPM / ECAPM / Bond Yield Risk Premium

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current Value Line Beta	11.45%	11.42%	11.39%
Current Bloomberg Beta	10.78%	10.74%	10.68%
Long-term Avg. Value Line Beta	10.48%	10.43%	10.37%
ECAPM:			
Current Value Line Beta	11.80%	11.78%	11.75%
Current Bloomberg Beta	11.29%	11.26%	11.22%
Long-term Avg. Value Line Beta	11.07%	11.03%	10.98%
Bond Yield Risk Premium:	10.27%	10.20%	10.10%

Q104. What is your conclusion regarding the Company's proposed capital structure?

A104. My conclusion is that Montana-Dakota's proposal to establish a capital structure for ratemaking purposes consisting of 50.185 percent common equity, 45.296 percent long-term debt, and 4.519 percent short-term debt is reasonable when compared to the capital