DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER of the Application of	)	REGULATORY DIVISION
MONTANA-DAKOTA UTILITIES CO., a	)	
Division of MDU Resources Group, Inc.,	)	Docket No. D2012.9.100
for Authority to Establish Increased	)	
Rates for Natural Gas Service	)	

Direct Testimony of
Albert E. Clark
on behalf
of
The Montana Consumer Counsel

February 25, 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Albert E. Clark. I am an independent consultant in the field of utility rates and regulation. My business address is 2871 S. Conway Road #127, Orlando, FL. 32801.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree in mathematics and secondary education in 1966 from Towson State University, Baltimore, Maryland. In 1975 I received a Certificate in Data Processing, Summa Cum Laude, from Anne Arundel Community College, Arnold, Maryland, where I also completed selected courses in accounting. I have studied at Rollins College, Winter Park, Florida, where I took graduate level courses in management with a concentration in accounting. I also hold a Master of Accounting degree from the George Washington University, Washington, D.C.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE IN THE FIELD OF PUBLIC UTILITY REGULATION?

A. From 1972 through 1986 I worked for several consulting firms in the Washington, D.C. area and in Orlando, Florida. During those engagements I participated in numerous rate proceedings before Federal and state regulatory agencies. I proceeded from assisting senior consultants in the preparation of analyses related to fully allocated cost of service and rate design studies to providing expert testimony

and analyses to clients in contested wholesale and retail rate cases. These cases involved cost allocation, rate design and revenue requirements analyses.

In 1986 I participated in the formation of another consulting firm where I was a Principal and a Vice President until I resigned in mid-1997. At that firm my primary efforts were in the areas of cost of service and revenue requirements studies in wholesale and retail rate proceedings before Federal and State regulatory agencies. I also assisted various clients - principally wholesale municipalities and cooperatives -- with negotiations for power supply and transmission services. In 1997 I formed Clark Utility Consulting, Inc. and performed similar types of services for clients as I had previously done. In January 2000 I joined the firm of Fred Saffer & Associates in Orlando, Florida. Since 2008 I have worked as an independent consultant.

Q. WHAT TYPES OF CLIENTS HAVE YOU SERVED DURING YOUR REGULATORY CONSULTING CAREER?

A. During the course of my regulatory consulting career, I have been retained by state regulatory commissions, state consumer protection agencies, Federal agencies, municipalities, industrial corporations, trade associations, electric cooperatives and municipally owned electric distribution systems.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN PUBLIC UTILITY RATE PROCEEDINGS?

A. Yes, I have provided expert testimony on over 115 occasions in 16 jurisdictions in

more than 85 separate proceedings. I have testified before this Commission in most of the proceedings involving Montana-Dakota Utilities Co.'s electric and natural gas utilities since 1984.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Montana Consumer Counsel (MCC).

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

A. Montana-Dakota Utilities Co. (MDU or the Company) has proposed to increase rates for gas distribution service to the customers that it serves within the state of Montana. The requested increase amounts to $3,455,478 (per Exhibit No.___ (RAM-1) or $3,457,412 (per the Transmittal Letter). The Company's requested increase is approximately 5.9% of total revenues and approximately 17.2% of the non-gas costs on a per books basis for 2011. The MCC has requested that I review the Company's filing and supporting documentation to determine if the Company's requested increase is appropriate.

The purpose of my testimony in this case is to present my conclusions and recommendations to the Commission regarding MDU's test year revenue requirements. I will address all revenue requirement issues raised by the filing except the appropriate capital structure and cost of capital which are being addressed by Dr. John Wilson. Additionally, the appropriate level of the prospective depreciation rates is being addressed by MCC witness Mr. Jacob Pous.

Q. HAVE YOU PREPARED EXHIBITS TO SUPPORT YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING?

A. Yes, in addition to my Direct Testimony, I have prepared Exhibit No.___ (AEC-1) through Exhibit No.___ (AEC-4). Exhibit No.___ (AEC-1) shows the calculation of the revenue change that I recommend in this testimony. Exhibit No.___ (AEC-2) is the Income Statement exhibit and shows the test year income statement per books, as adjusted by MDU and as adjusted by the MCC. Exhibit No.___ (AEC-3) is the rate base exhibit and is similar in format to Exhibit No.___ (AEC-2). Exhibit No.___ (AEC-4) is a compendium of schedules with four work papers attached that show the calculations of adjustments that I am proposing in this case.

Q. WHAT IS THE TEST YEAR IN THIS CASE?

A. The Company has proposed to use an historical test year ended December 31, 2011. I accept the use of this historical period, as adjusted, for the test year in this case. The Company has made many adjustments to the historical test year that are asserted to be "known and measurable" – i.e., known with certainty and measurable with reasonable accuracy at the time of the filing. In reality, however, the Company has made substantial post-test year adjustments that are based solely on the 2012 operating budget and, for all practical purposes, pro form the historical test year into a budgeted 2012 test year. As will be discussed more fully below, a budget is not an appropriate basis to be used to determine known and measurable changes as contemplated by the Commission.

Q. WHAT CONCLUSIONS HAVE YOU REACHED REGARDING MONTANA-DAKOTA UTILITIES CO.'S REQUESTED ANNUAL REVENUE INCREASE IN THIS CASE?

A. I first conclude the MDU's requested annual revenue increase is excessive and should not be allowed by this Commission. Secondly, I conclude that the Commission should order a revenue increase of no more than $421,966. Both of these conclusions are based on my analyses and the cost of capital recommendations of MCC witness Dr. Wilson. Additionally, my conclusion regarding the allowable revenue change includes the impact of the change to MDU's proposed depreciation rates recommended by Mr. Pous. As noted in the Direct Testimony of MDU's witness Mr. David L. Goodin, "The primary reason for the increase in rates is the increased investment in facilities and the associated depreciation, operation and maintenance expenses and taxes associated with the increase in investment." (Goodin Direct at page 6.) As I will show below, the labor costs and the benefit costs, among other costs are overstated in MDU's filing.

Q. LET US TURN TO YOU EXHIBIT NO.___ (AEC-4). WOULD YOU PLEASE EXPLAIN THE FIRST ADJUSTMENT THAT YOU ARE PROPOSING TO MONTANA-DAKOTA UTILITIES, CO. PRO FORMA RESULTS OF OPERATIONS?

A. Yes, I will. I am proposing to restate test period late payment revenues to an average that incorporates the latest known information that I have. If available, and reasonable, the latest known data should be used to pro form an historical test year. I propose to use an average that runs from January 2009 through October 2012. Using the later average results in a reduction to the test period late payment revenues of $1,356. The adjustment is calculated in Exhibit No.___ (AEC-4), page

3 of 18. It is brought forward to page 1 and subsequently to Exhibit No.___ (AEC-2). There is also a similar adjustment to the Company's penalty revenues. Using the same theory and methodology, I propose to increase the test year level of penalty revenues by $3,810. This adjustment is calculated in Exhibit No.___ (AEC-4), page 4 of 18 and comes forward to page 1 and then to Exhibit No.___ (AEC-2).

Q. ARE YOU PROPOSING ANOTHER ADJUSTMENT TO THE COMPANY'S TEST PERIOD OTHER REVENUES?

A. Yes, I am. I am proposing to shorten the amortization period over which gains and losses on the disposition of property is recognized for ratemaking purposes. As can be seen in the Statement H Work Papers at page H-61, MDU has chosen a five year amortization period. I am proposing to use a three year amortization period. I base the three year amortization on my perception of what is apparently the Company's expectation of when another rate case may be forthcoming. My perception is based on the Company's proposal to amortize rate case expense over three years. This adjustment increases test year revenues associated with the gain/loss on the disposition of property by $15,173. The adjustment is calculated in Exhibit No.___ (AEC-4), page 5 of 18. It is brought forward to page 1 and then to Exhibit No.___ (AEC-2).

Q. WHAT IS YOUR NEXT ADJUSTMENT TO MDU'S PRO FORMA INCOME STATEMENT?

A. My next adjustment reduces the proposed test year labor expense by $69,920. The basis of the adjustment is to use a percentage increase of 3.693% in lieu of the 4.742% used by MDU to calculate what is essentially a 2012 labor expense.

I propose to use the 3.693% factor because it excludes the impact of the severance payment made in 2009 and then amortized over three years. Those three years were 2009, 2010 and 2011. Therefore, as a known and measurable change for the 2012 adjustment period, I remove that cost. That removal reduces the increase in the test year level of labor costs. The adjustment is calculated in Exhibit No.___ (AEC-4), page 6 of 18. It is brought forward to page 1 and then to Exhibit No.___ (AEC-2).

There are two other adjustments associated with the change in labor expense. The level of workers compensation is based on the test year labor expense. Therefore, the test year workers compensation expense is reduced by $614 on Exhibit No.___ (AEC-4), page 7 of 18. Also, the test year level of labor related taxes is based upon the level of test year labor expense. The required reduction to labor related taxes, in the amount of $5,277, is calculated in Exhibit No.___ (AEC-4), page 8 of 18. Both of these labor related adjustments are brought forward to page 1 and then to Exhibit No.___ (AEC-2).

Q. WOULD YOU EXPLAIN YOUR ADJUSTMENT TO MDU'S POST RETIREMENT BENEFITS EXPENSES?

A. Yes, I will. My next adjustment is simply to recognize a correction noted in the Company's response to Data Request No. MCC-131. Therein, the Company acknowledged a reduction in post-retirement benefits of $44,667. That reduction is included in my pro forma test year in Exhibit No.__(AEC-4), page 7 of 18 and brought forward to page 1 and then to Exhibit No.___(AEC-2).

Q. WHAT IS THE NEXT ADJUSTMENT THAT YOU ARE PROPOSING?

A. My next adjustment reduces MDU's pro forma advertising expense by $9,513. As with my adjustment to post retirement benefits, the reduction to advertising expenses was noted in the Company's response to Data Request No. MCC-033. The adjustment is shown on Exhibit No.__ (AEC-4), page 1 of 18, column (H) and is brought forward to Exhibit No.___ (AEC-2).

Q. PLEASE EXPLAIN YOUR NEXT PROPOSED ADJUSTMENT TO MDU'S PRO FORMA INCOME STATEMENT.

A. My next adjustment reduces the test year level of expense for the MPSC/MCC taxes to reflect the latest known rates for both. The MPSC tax goes up while the MCC tax goes down. The net effect is a reduction to the Company's test year expense of $11,793. The adjustment is calculated in Exhibit No.___ (AEC-4), page 9 of 18. It is brought forward to page 1 and then to Exhibit No.___ (AEC-2).

Q. WHAT IS YOUR NEXT ADJUSTMENT TO THE PRO FORMA INCOME STATEMENT?

A. I am proposing to reduce test year postage expense by $7,919. A review of the Company's Statement Work Papers at page G-100 indicates an expected reduction in postage expense for the Montana gas operations for 2012 as compared to 2011. A hand written note on the work paper indicates that the Company opted not to make the adjustment. My proposed adjustment provides for the expected gas utility reduction in postage expense as shown on the referenced work paper. The adjustment is shown on Exhibit No.___ (AEC-4, page 1 of 18, column (J) and is brought forward to Exhibit No.___ (AEC-2).

Q. PLEASE EXPLAIN YOUR NEXT ADJUSTMENT.

A. I have increased the depreciation expense associated with vehicles and work equipment. This adjustment stems from the Company's response to Data Request No. MCC-030, wherein a mistake was noted and corrected. I have included that correction in Exhibit No.___ (AEC-4), page 1, column (K).

Q. WHAT IS YOUR NEXT PROPOSED ADJUSTMENT TO THE COMPANY'S INCOME STATEMENT?

A. I am proposing to reduce the expenses associated with the board of directors meetings for 2011. First, I use the expenses associated with the 2012 meetings as a known and measureable change to the 2011 actual costs. Second, I am proposing to reduce the 2012 costs to remove the differential for the cost of meeting that took

place in Palm Springs, California. The Commission has approved this same adjustment in prior MDU rate cases. To accomplish this piece of the adjustment, I first compute an average for the three other 2012 meetings. I use that average to compute a cost for the entire year. I then compare that amount to the total cost of the 2011 meetings. That results in a reduction of $39,149. I then allocate this total to the gas utility and then to the Montana jurisdiction. I followed the allocation process used by MDU to allocate Director and Officer Liability insurance as shown in the Statement Work Papers at page E-4. My calculation is shown in Exhibit No.___ (AEC-4), page 10 of 18 and is brought forward to page 1 and then to Exhibit No.___ (AEC-2).

Q. WOULD YOU EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S PRO FORMA INTEREST EXPENSE?

A. This adjustment to the pro forma income statement is to synchronize the interest expense with the capital structure and the rate base plus non-rate base construction work in progress. In the response to Data Request No. MCC-169, MDU provided the appropriate number to use in the calculation. The calculation of the synchronized interest expense is shown in Exhibit No.___ (AEC-4) at page 17 of 18. The rate base is $38,592,519. I have added the non-rate base construction work in progress provided in the response noted above. The weighted debt cost is based on the capital structure and cost of debt included in the testimony and exhibits of MCC witness Dr. Wilson – specifically as summarized in his Direct Testimony at page 38. The impact of this adjustment is to increase current income tax expense by $17,269.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S PROPOSED PRO FORMA RATE BASE?

A. Yes, I am proposing adjustments to the prepaid insurance, the prepaid demand/commodity charge and the materials and supplies. These three adjustments are all based on using more current information. All three of these adjustments use a thirteen month average for the period ending October 2012. The more recent data is preferable to the Company's use of the period ending June 2012. These adjustments, which raise the Company's proposed rate base, are calculated in Exhibit No.___ (AEC-4), pages 11, 12, and 13 of 18, respectively. They are brought forward to page 2 and then to Exhibit No.___ (AEC-3).

Q. ARE YOU PROPOSING ANY OTHER RATE BASE ADJUSTMENTS?

A. Yes, I am proposing to reduce the amount of post-test year plant included in the Company's pro forma rate base. Based on the Company's response to Data Request No. MCC-055, I have removed plant that did not go into service by the close of the allowed adjustment through December 31, 2012. I have also changed the estimated cost of some projects to the actual cost of those projects where the Company provided such information. By far, the largest project that I am removing is the customer information system that did not go into service in 2012. My adjustment to average plant in service, in the amount of $(3,983,699), is calculated on Exhibit No.___ (AEC-4), page 14 of 18. The support for the adjustment is shown in the post test year plant work paper which is attached to the exhibit.

There are two adjustments associated with the removal of some of the post-test year plant. These are to the accumulated provision for depreciation (APFD)

and the accumulated deferred income taxes (ADIT). The Company provided the total APFD and ADIT related to the Company's proposed level of plant. I have used a ratio of my proposed plant to the Company's proposed plant to reduce the associated APFD and ADIT, thereby increasing the rate base. These adjustments in the amount of $142,731 and $842,382 respectively are calculated in Exhibit No.___(AEC-4), page 15 of 18 and brought forward to page 2 and then to Exhibit No.___(AEC-3).

Q. ARE YOU PROPOSING ANY ADDITIONAL ADJUSTMENTS TO MDU'S PRO FORMA RATE BASE?

A. Yes, there is one final adjustment to MDUC's pro forma rate base that also impacts the income statement. MDU is proposing to include the full investment and operating costs of the Billings Landfill project in base rates at this time. The Montana portion of the project results in an increase to the revenue requirement of $698,870. Given the current level of output from the project the result is a gas cost of between $17 to over $19 per dekatherm (Dkt). The resulting unit cost is out-of-market by a factor of approximately 5 and exceeds the originally projected unit costs by a factor of approximately 4.

I am proposing to remove all investment and operating expenses associated with this exceedingly costly project. Since the gas is being included in MDU's system supply and since MDU is paying the City of Billings a royalty based on the CIG Index price, I recommend that the volumes produced at the project be priced at the CIG Index price in the gas tracker cases. In the Company's response to Data Request No. MCC-078, the CIG Index is expected to be in the range from a low of

$3.334 (April 2013) to a high of $4.206 (December 2015).

In response to Data Request No. MCC-133, MDU provided a calculation of the Montana portion of the total project as included in this case. That calculation resulted in a revenue requirement of $699,202. I believe there was a small error in the calculation in the measurement of the accumulated provision for depreciation. The Company used $102,009 while I believe the proper amount should be $153,372. By making this change, the revenue requirement associated with the project is reduced slightly to $698,870. My calculation is shown in Exhibit No.___ (AEC-4), page 16 of 18. It is brought forward to page 2 of 18 and subsequently included in Exhibits No.___ (AEC-1) and (AEC-2).

Q. WOULD YOU PROVIDE THE COMMISSION WITH YOUR CONCLUSIONS AND RECOMMENDATIONS CONCERNING THE ALLOWABLE REVENUE CHANGE BASED ON YOUR ANALYSIS?

A. Yes, I will. I conclude that the Company's requested revenue increase of $3,457,412 is excessive and I recommend that the Commission reject the Company's request for that level of increase. I further conclude that the Company is actually requires an increase in revenues of no more than $421,966 from its Montana gas operations on a pro forma basis. Both my conclusions and recommendations are based on my analysis of the Company's filing and supporting data and information and the use of cost of capital and capital structure recommendations of MCC witness Dr. John W. Wilson. My conclusions and recommendations also reflect the depreciation rates proposed by MCC witness Mr. Jacob Pous.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES, CO.
Calculation of Required Revenue Increase
Gas Utility - Montana
Twelve Months Ended December 31, 2011

		Pro Forma Per MCC	Additional Revenue Requirement	Reflecting Additional Revenue Requirement
	(A)	(B)	(C)	(D)
	Operating revenues			
1	Sales	$57,791,481	$421,966	$58,213,447
2	Transportation	1,131,533		1,131,533
3	Other	433,739		433,739
4	Total Revenues	$59,356,753	$421,966	$59,778,720
	Operating Expenses			
	Operation and Masintenance			
5	Cost of Gas	$38,854,572		$38,854,572
6	Other O&M	10,782,479		10,782,479
7	Total O&M	$49,637,051		$49,637,051
8	Depreciation	3,497,027		3,497,027
9	Taxes other than income taxes	3,190,253	1,350	3,191,603
10	Current income taxes	-2,985,872	165,670	-2,820,202
11	Deferred income taxes	3,334,426		3,334,426
12	Total Operating Expenses	$56,672,886	$167,020	$56,839,906
13	Operating Income	$2,683,868	$254,997	$2,938,865
14	Average Rate Base	$38,592,519		$38,592,519
15	Rate of Return	6.954%		7.615%

Sources:
Column (B): Exhibit No.___(AEC-2), page 1, column (F)

MONTANA-DAKOTA UTILITIES, CO.
Income Statement
Gas Utility - Montana
Twelve Months Ended December 31, 2011

Line No.	(A)	Per Books (B)	Company Pro Forma Adjustments (C)	Pro Forma Per Company (D)	MCC Pro Forma Adjustments (E)	Pro Forma Per MCC (F)
	Operating revenues					
1	Sales	$72,489,259	-$14,697,778	$57,791,481	$0	$57,791,481
2	Transportation	1,252,889	-121,356	1,131,533	0	1,131,533
3	Other	368,826	47,286	416,112	17,627	433,739
4	Total Revenues	$74,110,974	-$14,771,848	$59,339,126	$17,627	$59,356,753
	Operating Expenses					
	Operation and Maintenance					
5	Cost of Gas	$52,735,031	-$13,880,459	$38,854,572	$0	$38,854,572
6	Other O&M	10,869,311	247,767	11,117,078	-334,599	10,782,479
7	Total O&M	$63,604,342	-$13,632,692	$49,971,650	-$334,599	$49,637,051
8	Depreciation	$3,011,298	$1,412,304	$4,423,602	-$926,575	$3,497,027
9	Taxes other than income taxes	3,308,019	-32,520	3,275,499	-85,246	3,190,253
10	Current income taxes	-2,930,186	-362,889	-3,293,075	307,203	-2,985,872
11	Deferred income taxes	3,489,201	-154,775	3,334,426	0	3,334,426
12	Total Operating Expenses	$70,482,674	-$12,770,572	$57,712,102	-$1,039,216	$56,672,886
13	Operating Income	$3,628,300	-$2,001,276	$1,627,024	$1,056,844	$2,683,868
14	Average Rate Base	$43,247,498	$512,333	$43,759,831	-$5,167,312	$38,592,519
15	Rate of Return	8.390%		3.718%		6.954%

Sources:
Columns (B) - (D): Rule 38.5.157, page 1 of 7, page 3 of 7 and Exhibit No.___(RAM-1)
Column (E): Exhibit No.___ (AEC-4)

MONTANA-DAKOTA UTILITIES, CO.
Average Rate Base
Gas Utility - Montana
Twelve Months Ended December 31, 2011
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Line No.	(A)	Per Books (B)	Company Pro Forma Adjustments (C)	Pro Forma Per Company (D)	MCC Pro Forma Adjustments (E)	Pro Forma Per MCC (F)
1	Gas plant in service	$94,105,839	$6,357,622	$100,463,461	-$7,092,908	$93,370,554
2	Accumulated reserve for depreciation	51,259,183	3,202,646	54,461,829	-712,331	53,749,498
3	Net gas plant in service	42,846,656	3,154,976	46,001,632	-6,380,576	39,621,056
4	CWIP in service not classified	500,474	0	500,474		500,474
5	Total gas plant in service	43,347,130	3,154,976	46,502,106	-6,380,576	40,121,530
	Additions:					
6	Materials and Supplies	533,337	99,695	633,032	82,877	715,909
7	Gas in underground storage	7,134,766	-855,502	6,279,264		6,279,264
8	Prepayments	1,175,889	-549,107	626,782	33,078	659,860
9	Gas IRP	0	0	0		0
10	Unamortized gain (loss) on debt	584,820	-53,806	531,014		531,014
11	Provision for pensions and benefits	0	1,268,837	1,268,837		1,268,837
12	Deferred FAS 106 costs	128,892	273,775	402,667		402,667
13	Total Additions	9,557,704	183,892	9,741,596	115,954	9,857,550
	Deductions					
14	Proivision for injuries and damages	0	109,736	109,736		109,736
15	Accumulated deferred income taxes	8,925,996	2,741,213	11,667,209	-1,097,310	10,569,899
16	Accumulated Investment Tax Credits	4,084	-3,488	596		596
17	Customer advances	727,256	-20,926	706,330		706,330
18	Total Deductions	9,657,336	2,826,535	12,483,871	-1,097,310	11,386,561
19	Total Rate Base	$43,247,498	$512,333	$43,759,831	-$5,167,312	$38,592,519

Sources:
Columns (B) - (D): Rule 38.5.175, Page 6 of 7
Column (E): Exhibit No.___ (AEC-4)

MONTANA-DAKOTA UTILITIES, CO.
Summary of Income Statement Adjustments
Gas-Utility - Montana
Test Year Ended December 31, 2011

Line No.	(A)	Late Pay Revenues (B)	Penalty Revenues (C)	Gain/Loss Prop Disp (D)	Labor (E)	Fringe Benefits (F)	Labor Taxes (G)	Advertising (H)	MPSC/MCC Taxes (I)	Postage (J)	Vehicles & Work Equip. (K)	BOD Meetings (L)	Subtotal Adjustments (M)
	Operating revenues												
1	Sales											$0	$0
2	Transportation												0
3	Other	-1,356	3,810	15,173					0				17,627
4	Total Revenues	-$1,356	$3,810	$15,173	$0	$0	$0	$0	$0	$0	$0	$0	$17,627
	Operating Expenses												
	Operation and Maintenance												
5	Cost of Gas											$0	$0
6	Other O&M	0	0	0	-69,920	-45,281	0	-9,513		-7,919		-4,236	-136,870
7	Total O&M	$0	$0	$0	-$69,920	-$45,281	$0	-$9,513	$0	-$7,919	$0	-$4,236	-$136,870
8	Depreciation										9,415		9,415
9	Taxes other than income taxes						-5,277	0	-11,793				-17,070
10	Current income taxes	-534	1,501	5,976	27,540	17,835	2,079	3,747	4,645	3,119	-3,708		62,199
11	Deferred income taxes												0
12	Total Operating Expenses	-$534	$1,501	$5,976	-$42,380	-$27,446	-$3,199	-$5,766	-$7,148	-$4,800	$5,707	-$4,236	-$82,326
13	Operating Income	-$822	$2,309	$9,197	$42,380	$27,446	$3,199	$5,766	$7,148	$4,800	-$5,707	$4,236	$99,953
14	Rate Base												$ -
		Page 3	Page 4	Page 5	Page 6	Page 7	Page 8	MCC-033	Page 9	Stmt WP G-100	MCC-030	Page 10	

MONTANA-DAKOTA UTILITIES, CO.
Summary of Income Statement Adjustments
Gas-Utility - Montana
Test Year Ended December 31, 2011

Line No.	(A)	Prepaid Insurance (B)	Prepaid Dem/Comm Charge (C)	Materials and Supplies (D)	Post Tesy Year Plant (E)	Post Test Year APFD (F)	Post Test Year ADIT (G)	Billings Landfill (H)	Depreciation Rates (I)	(J)	(K)	Interest Expense (L)	Total Adjustments (M)
	Operating revenues												
1	Sales												$0
2	Transportation												-
3	Other												17,627
4	Total Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,627
	Operating Expenses												
	Operation and Maintenance												
5	Cost of Gas												$0
6	Other O&M							(197,729)					(334,599)
7	Total O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ (197,729)	$ -	$ -	$ -	$ -	$ (334,599)
8	Depreciation							(103,537)	(832,453)				(926,575)
9	Taxes other than income taxes							(68,176)					(85,246)
10	Current income taxes							(100,147)	327,882			17,269	307,203
11	Deferred income taxes												-
12	Total Operating Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ (469,589)	$ (504,571)	$ -	$ -	$ 17,269	$ (1,039,216)
13	Operating Income	$ -	$ -	$ -	$ -	$ -	$ -	$ 469,589	$ 504,571	$ -	$ -	$ (17,269)	$ 1,056,844
14	Rate Base	$ 1,893	$ 31,184	$ 82,877	$ (3,983,699)	$ 142,731	$ 842,382	$ (2,700,919)	$ 416,238				$ (5,167,312)
		Page 11	Page 12	Page 13	Page 14	Page 15	Page 15	Page 16	Work papers 2-4			Page 17	

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Late Payment Revenues

		Per Books Montana	Pro Forma Per MDU	MCC Adjustment
	(A)	(B)	(C)	(D)
1	2009	$ 51,553		
2	2010	$ 43,770		
3	2011	$ 45,851		
4	January - October 2012	$ 29,391		
5	Average for 3 and 10/12 years	$ 44,495	$ 45,851	$ (1,356)

Sources and references:
Rule 38.5.164, Statement H, page 6 of 7
Company response to Data Request No. MCC-009

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Late Penalty Revenues

		Per Books Montana	Pro Forma Per MDU	MCC Adjustment
	(A)	(B)	(C)	(D)
1	2009	$ 7,304		
2	2010	$ 15,845		
3	2011	$ 36,077		
4	January - October 2012	$ 31,056		
5	Average for 3 and 10/12 years	$ 23,552	$ 19,742	$ 3,810

Sources and References:
Rule 38.5.164, Statement H, page 6 of 6
Company response to Data Request No. MCC-010

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Gains and Losses on Disposal of Property

		Totals	2007	2008	2009	2010	2011	2012	2013
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Gain on disposal of property								
1	2007	$ 53,565	$17,855	$17,855	$17,855	$0	0	0	$0
2	2008	-	0	0	0	0	0	0	0
3	2009	4,280	0	0	1,427	1,427	1,427	0	0
4	2010	(325)	0	0	0	-108	(108)	(108)	0
5	2011	106,625	0	0	0	0	35,542	35,542	35,542
6	Total gains	$ 164,145	$ 17,855	$ 17,855	$ 19,282	$ 1,318	$ 36,860	$ 35,433	$ 35,542
	Loss on Disposal of Property								
7	2007	$ -							
8	2008	-							
9	2009	(14,260)			(4,753)	(4,753)	(4,753)		
10	2010	(7,470)				(2,490)	(2,490)	(2,490)	
11	2011	-							
12	Total losses	$ (21,730)	$ -	$ -	$ (4,753)	$ (7,243)	$ (7,243)	$ (2,490)	$ -
13	Net gain/(loss) on disposal of property		$ 17,855	$ 17,855	$ 14,528	$ (5,925)	$ 29,617	$ 32,943	$ 35,542
14	Pro forma net gain/(loss) per Company							17,770	
15	Adjustment to other revenues							$ 15,173	

Sources and references:
Statement Work papers, Statement H, page H-61

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Wage and Salary Expense

Line No.	(A)	Per Books Montana (B)	Pro Forma Montana (C)	MDU Pro Forma Montana (D)	Proposed MCC Adjustment (E)
1	Other gas supply	$ 52,641	$ 54,585	$ 55,136	$ (551)
2	Production	18,149	18,819	29,483	(10,664)
3	Distribution	3,390,504	3,515,731	3,551,214	(35,483)
4	Customer accounting	1,055,275	1,094,251	1,105,295	(11,044)
5	Customer service	55,811	57,872	58,456	(584)
6	Sales	86,721	89,924	90,832	(908)
7	Admin & general	1,021,246	1,058,965	1,069,653	(10,688)
8	Total	$5,680,347	$5,890,149	$5,960,069	$ (69,920)

		2011 Total	Pro Forma
9	5110	$ 40,601,222	$ 41,701,320
10	5120	3,593,762	3,691,136
11	5130	1,705,117	
12	5131	2,098,089	
13	5140	133,594	137,213
14	5150	48,047	49,349
15	5193	372,609	382,705
16	Total	$ 48,552,440	$ 45,961,723
	3 year average restated incentive compensation w/o severance		4,383,987
	Total		$ 50,345,710
	Per cent change		3.693%

Column (B), Lines 1-8: Rule 38.5.157, Statement G, Page 4 of 15
Column (C): Column (B) increased by 3.693% per lines 9 - 16
Column (D), Lines 1-8: Rule 38.5.157, Statement G, page 4 of 15
Column (E), Lines 1-8: Column (C) less Column (D)

Lines 9 - 16: Statement Work papers, page G-41

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Fringe Benefits Expense

	(A)	Per Books Montana (B)	Pro Forma Montana (C)	MDU Pro Forma Montana (D)	Proposed MCC Adjustment (E)
1	Medical/Dental	$ 623,431	$ 628,980	$ 628,980	$ -
2	Pension expense	155,387	(64,455)	-64,455	0
3	Post-retirement	152,499	339,539	384,206	-44,667
4	401 - K	605,091	689,804	689,804	0
5	Workers comp (1)	50,015	51,769	52,383	-614
6	SISP	179,996	-	0	0
7	Total	$1,766,419	$1,645,637	$1,690,918	-$45,281

(1) Pro forma labor expense times 0.008789 per Statement Work Papers, page G-44.

Sources and references:
Column (B): Rule 38.5.157, Statement G, Page 5 of 15
Company response to Data Request No. MCC-131

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Payroll Taxes

		Per Books Montana	Pro Forma Montana	MDUC Pro Forma Montana	Proposed MCC Adjustment
	(A)	(B)	(C)	(D)	(E)
1	Total payroll taxes	$428,471			
4	Labor expense	$5,690,347			
5	Ratio of taxes to payroll	7.5298%			
6	Pro Forma labor expense		$5,890,149		
7	Labor related taxes		$443,516	$448,793	-$5,277

Lines 1 & 2: Rule 38.5.174, Statement K, page 3 of 5
Line 4: Rule 38.5.157, Statement G, page 4 of 22
Column (C): Page 4, herein
Column (D): Rule 38.5.174, Statement K, page 3 of 4

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Change MPSC and MCC Tax Rates

Line No.		MPSC Tax	MCC Tax	Total
	(A)	(B)	(C)	(D)
1	Taxable revenue	$ 58,962,755	$ 58,962,755	
2	MPSC tax at 0.23%	$ 135,614		
3	MCC tax @0.07%		$ 41,274	
4	Pro forma tax per MDU	117,926	70,755	
5	Adjustment	$ 17,688	$ (29,481)	$ (11,793)

Sources and references:
Rule 38.5.174, Statement K, page 4 of 4
Company response to Data Request No. MCC-048

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Board of Directors Meetings Expense

Line No.		Total Cost	Gas Portion @ 43.70%	Montana Portion @24.761%
	(A)	(B)	(C)	(E)
1	Feb 2011 - Palm Springs	$ 64,902		
2	May 2011 - Bismarck	57,444		
3	Aug 2011 - Bismarck	54,827		
4	Nov 2011 - Bismarck	39,051		
5	Total	$ 216,225		
5	Feb 2012 - Palm Springs	$ 58,603		
6	May 2012 - Bismarck	$ 37,719		
7	Aug 2012 - Bay Harbor	$ 58,313		
8	Nov 2012 - Denver	$ 36,775		
9	Avg of May, Aug & Nov	$ 44,269		
10	Line 9 times 4	$ 177,076		
11	Adjustment	$ (39,149)	$ (17,108)	$ (4,236)

Sources and references:
Company response to Data Request No. PSC-022
Allocation per Statement Work Papers, page E-4, D&O Liability Insurance

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Prepaid Insurance

		Per Books Montana		Pro Forma Montana	MDU Pro Forma Montana	Proposed MCC Adjustment
	(A)	(B)		(C)	(D)	(E)
1	December 2010	$ 23,075	December 2011	$28,741		
2	January 2011	221,728	January 2012	244,853		
3	February	214,702	February	225,487		
4	March	193,742	March	203,043		
5	April	172,792	April	180,600		
6	May	151,843	May	158,489		
7	June	130,893	June	136,036		
8	July	109,943	July	113,583		
9	August	88,994	August	91,130		
10	September	68,044	September	68,677		
11	October	52,716	October	52,073		
12	November	49,466				
13	December	28,741				
14	Thirteen month average balance	$ 115,898		$121,609	$ 119,716	$ 1,893

Sources and references:
Rule 38.5.143, Statement E, page 3 of 9
Company response to Data Request No. MCC-062

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Prepaid Demand and Commodity Charges

		Per Books Montana		Pro Forma Montana	MDU Pro Forma Montana	Proposed MCC Adjustment
	(A)	(B)		(C)	(D)	(E)
1	December 2010	$ 1,086,349	December 2011	$1,213,615		
2	January 2011	(171,300)	January 2012	-52,608		
3	February	(927,762)	February	-897,713		
4	March	(1,399,781)	March	-1,359,423		
5	April	(1,312,777)	April	-1,265,136		
6	May	(809,527)	May	-757,031		
7	June	(31,451)	June	-18,748		
8	July	785,971	July	685,471		
9	August	1,615,572	August	1,375,916		
10	September	2,428,885	September	2,252,397		
11	October	2,703,035	October	2,438,234		
12	November	2,168,667				
13	December	1,213,615				
14	Thirteen month av	$ 565,346		$538,250	$ 507,066	$ 31,184

Sources and references:
Rule 38.5.143, Statement E, page 4 of 9
Company response to Data Request No. MCC-063

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Material and Supplies

		Per Books Montana		Pro Forma Montana	MDU Pro Forma Montana	Proposed MCC Adjustment
	(A)	(B)		(C)	(D)	(E)
1	December 2010	$ 508,979	December 2011	$557,694		
2	January 2011	491,311	January 2012	571,628		
3	February	490,913	February	609,874		
4	March	483,398	March	609,597		
5	April	553,150	April	672,668		
6	May	559,282	May	824,045		
7	June	567,033	June	862,822		
8	July	573,017	July	839,071		
9	August	567,190	August	874,082		
10	September	607,577	September	852,369		
11	October	609,349	October	869,012		
12	November	606,259				
13	December	557,694				
14	Thirteen month av	$ 551,935		$715,909	$ 633,032	$ 82,877

Sources and references:
Rule 38.5.143, Statement E, page 1 of 9
Company response to Data Request No. MCC-058

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Post Test Year Additions

Line No.	(A)	Balance @ 12/31/2010 (B)	Balance @ 12/31/2011 (C)	As filed Average at 12/31/2011 (E)	Allowable Plant Additions (F)	Balance at 12/31/2012 (G)	Average Balance (H)	Average Balance per MDU (I)	MCC Adjustment (J)
1	Production plant	$ 2,972,781	$ 3,096,756	$ 3,034,769	$ 24,775	$ 3,059,544	$ 3,078,150	$ 3,109,209	$ (31,059)
2	Distribution plant	70,105,115	73,250,276	71,677,695	2,298,364	73,976,059	73,613,168	74,788,173	(1,175,006)
3	General plant	5,953,718	6,010,708	5,982,213	171,682	6,153,895	6,082,302	6,292,122	(209,821)
4	Intangible plant - general	56,115	55,404	55,759	0	55,404	55,404	55,404	-
5	Common plant	10,639,185	10,552,679	10,595,932	470,326.0	11,066,258	10,809,469	10,762,369	47,100
6	Intangible plant - common	2,697,442	2,821,499	2,759,471	101,572	2,861,043	2,841,271	5,456,184	(2,614,913)
7	Total gas plant in service	$ 92,424,356	$ 95,787,322	$ 94,105,839	$ 3,066,719	$ 97,172,203	$ 96,479,763	$ 100,463,461	$ (3,983,699)

Sources and references:

Rule 38.5.123, Statement C, Pages 3 - 5, of 5
Work paper 1, attached

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustments Related to Post Test Year Additions

Line No.		Average Plant Additions to Rate Base	Average APFD Rate Base	Average ADIT Rate Base
	(A)	(B)	(C)	(D)
1	Per MDU	$ 6,357,622	$ 227,786	$ 1,344,365
2	Per MCC	2,373,923	85,055	501,983
3	Adjustment	$ (3,983,699)	$ (142,731)	$ (842,382)
4	Per cent allowed (Line 2/Line 1)	37.33979%		

Sources and references
Column (B): Rule 38.5.123, Statement C, page 2 of 5 and Page 12, herein.
Column (C): Company's updated response to Data Request No. MCC-057
Column (D): Company's response to Data Request No. MCC-162

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Remove the Billings Landfill

	Rate Base				
1	Average plant in service	$ 3,109,209	Return at 8.489%	$	229,281
2	APFD	153,362	O&M expense		197,729
3	Net plant	2,955,847	Depreciation		103,537
4			Other taxes		68,176
5	Average ADIT	254,928	Income taxes		100,147
6	Total rate base	$ 2,700,919	Total revenue requirement	$	698,870

	Calculation of income tax:		
7	Return	$	229,281
8	Interest portion @2.783%		75,167
9	Equity portion	$	154,114
10	Gross up for icome taxes	$	254,262
11	Income taxes	$	100,147

12 Using the 140,000 dK annual ouptit fro MCC-134 and assuming Montana is 29% of the total system, the unit cost is equal to: $ 17.21

13 Using the actual 2011 output of 124,121 dK from MCC-078 and assuming Montana is 29% of the total system, the unit cost is equal to: $ 19.42

Sources and references:
Company's response to Data Request No. MCC-78
Company's response to Data Request No. MCC-133
Company's response to Data Request No. MCC-134
Rule 38.5.133, Statement D, page 2 of 2

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Synchronize Interest Expense

	(A)	(B)	(C)	(D)	(E)	(F)
1	Pro Forma Rate Base				$38,592,519	
2	CWIP not included in rate base				338,469	
3	Interest Base				38,930,988	
4	Long tern debt ratio				43.0780%	
5	Long tern debt cost				6.8460%	
6	Short term debt ratio				4.7500%	
7	Short term debt cost				1.3990%	
8	Weighted cost of debt				3.0156%	
9	Synchronized interest expense				$1,173,992	
10	Synchronized interst expense per MDU				1,217,836	
11	Adjustment to interest expense				-$43,844	
10	Income tax impact at 39.3875%				$17,269	

Line 1: Exhibit No.___(AEC-3)
Line 2:MDU response to Data Request MCC-169
Lines 4 - 8: Dr. John Wilson
Line 10: Rule 38.5.169, Statement J, Page 8 of 20

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Rate of Return

Line No.	(A)		Balance (B)	Ratio (C)	Cost (D)	Weighted Cost (E)
1	Long term debt	$	43,078	43.078%	6.846%	2.949%
2	Short term bebt		4,750	4.750%	1.399%	0.066%
3	Preferred stock		2,172	2.172%	4.583%	0.100%
4	Common Equity		50,000	50.000%	9.000%	4.500%
5	Total	$	100,000	100.000%		7.615%

Source:
Direct Testimony Of Dr. John W. Wilson, page 38

Docket No. D2012.9.100
Exhibit No.__(AEC-4)
Workpaper 1

MONTANA-DAKOTA UTILITIES, CO.
Gas Utility - Montana
Twelve Months Ended December 31, 2011
Adjustment to Post Test Year Additions

Line No.		As Filed Montana	As Revised Montana	MCC Adjustment
	(A)	(B)	(C)	(D)
	Production			
1	Landfill gas field expansion	$ 24,906	$ 24,775	$ (131)
	Distribution			
2	Repalce mains	$ 504,015	$ 386,796	$ (117,219)
3	Replace mains - Belfry	90,010	0	(90,010)
4	Phase 3 Loop - Glendive	55,917	0	(55,917)
5	Phase 2 Loop - Wibaux	39,142	0	(39,142)
6	4" main on Bench - Billings	22,506	0	(22,506)
7	Main Ave B East - Billings	129,305	130,189	884
8	Mains and services - Billings	31,853	17,761	- (14,092)
9	Mains Rimrock Rd - Billings	482,100	0	(482,100)
10	4" main extension - Billings	0	0	-
11	Meas & Reg Equipments	26,647	21,257	(5,390)
12	Service lines	969,829	822,180	(147,649)
13	Main Ave B-E services	180,002	196,319	16,317
14	Meters	395,073	511,167	116,094
15	Regulators	42,090	111,107	69,017
16	Cathodic protection	107,305	101588	-5,717
17	Total distribution	$ 3,075,794	$ 2,298,364	$ (777,430)
	General			
18	Gas vehicles	$ 139,603	$ 73,798	$ (65,805)
19	Minor work equipment	64,203	25,265	(38,938)
20	Gas work equipment	347,473	72,619	(274,854)
21	Communications - Billings	11,546	0	(11,546)
22	Total general	$ 562,825	$ 171,682	$ (391,143)
	Common			
23	Transpotation building roof	$ 4,947	$ 7,883	$ 2,936
24	Valves - thermo - annex	13,564	15,740	2,176
25	Backup generator - Glendive	19,077	-	(19,077)
26	Wolf Point office	4,059	4,748	689
27	Hydraulic gate - Dickensen SC	5,011	13,026	8,015
28	Roof - Dickenson Office	7,138	-	(7,138)
29	5th floor - HR	-	981	981
30	Conference room chairs	-	2,514	2,514
31	Tandem storage units	4,027	5,026	999
32	Color copier	15,797	20,151	4,354
33	B/W copier	19,592	24,991	5,399
34	Bill printer	29,594	45,768	16,174
35	Microfilm reader/printer	-	461	461
36	Workstation for land agent	-	895	895
37	HM panels for GO - 5th	-	622	622
38	Office equipment	14,964	3,514	(11,450)
39	Personal computers	30,326	27,818	(2,508)
40	50 replacement MDTs	16,340	22,193	5,853
41	Oracle Exadata platforms	10,846	139,660	128,814
42	Vehicles	66,479	78,286	11,807
43	Minor work equipment	14,211	8,953	(5,258)
44	Comminication equipment	63,425	36,448	(26,977)
45	GO phone system	47,553	-	(47,553)
46	Call recor system - call center	10,821	-	(10,821)
47	Network equipment	2,217	2,375	158
48	Network & Comm equipment - AMR	3,278	-	(3,278)
49	Polycom ubits - Conference rooms	2,984	-	(2,984)
50	Mail inserter	-	775	775
51	CTP equipment - print shop	7,505	-	(7,505)
52	DC6345 Cut/CRSR	3,175	4,049	874
53	UPS battery	562	716	154
54	Ice maker - Wolf Point	978	1,685	707
55	Ice machine - Dickenson	347	332	(15)
56	Pressure washer - Dickenson	561	716	155
57	Total Common	$ 419,378	$ 470,326	$ 50,948
	Common - Intangible			
58	Mobile work force software	$ 95,402	$ -	$ (95,402)
59	Field collector software	-	46,500	46,500
60	Customer Info System	4,937,603	-	(4,937,603)
61	ARCGIS Mobile	41,034	55,072	14,038
62	Automated Vehicle Loc. Software	19,900	-	(19,900)
63	Powerplan software	130,262	-	(130,262)
64	IVR - Web Direct	45,170	-	(45,170)
65	Total Common - Intangible	$ 5,269,371	$ 101,572	$ (5,167,799)
66	TOTAL	$ 9,352,274	$ 3,066,719	$ (6,285,555)

Sources and references:
Company response to Data Request No. MCC-055

Docket No. D2012.9.100
Exhibit No.___(AEC-4)
Workpaper 2

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF DEPRECIATION EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Function	2011 Per Books	Pro Forma Adjustment	Pro Forma Expense 1/
Production	$101,594	$1,943	$103,537
Distribution	2,367,765	332,850	2,700,615
General	115,122	(5,111)	110,011
Common	315,830	(101,349)	214,481
Common - Intangible	110,987	331,132	442,119
CWIP in Service		20,386	20,386
Total	$3,011,298	$579,851	$3,591,149

1/ See Work paper 3

Docket No. D2012.9.100
Exhibit No.___(AEC-4)
Workpaper 3

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011
PRO FORMA ADJUSTMENT NO. 15

Function	2011 Per Books	Pro Forma Expense 1/	Pro Forma Adjustment
Production	$101,594	$103,537	$1,943
Distribution	2,367,765	2,700,615	332,850
General	115,122	110,011	(5,111)
Common	315,830	214,481	(101,349)
Common - Intangible	110,987	442,119	331,132
CWIP in Service		20,386	20,386
Total	$3,011,298	$3,591,149	$579,851
Pro forma adjustment per MDU			1,412,304
MCC adjustment			($832,453)

Pro Forma Adjustment to Accumulated Reserve	$3,647,323
Pro forma adjustment per MDU	4,480,069
MCC adjustment (2)	$832,746

1/ Average annual depreciation expense on pro forma plant in service, see Rule 38.5.165, Statement I, pages 3-4.
(2) The average balance to be added to rate base is $416,373.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE DEPRECIATION EXPENSE
GAS UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2011

Acct. No	Account	Pro Forma Average Plant	Depreciation Rate	Annual Depreciation	Accumulated Reserve
	Production Plant				
333	Field Compressor Station Equip.	$3,109,209	3.33%	$103,537	$103,537
	Distribution Plant				
374.1	Land	$15,962			
374.2	Rights of Way	22,846	1.39%	$318	$318
375	Structures & Improvements	195,164	2.77%	5,406	5,406
376	Mains	29,580,663	**1.51%**	446,668	446,668
378	Meas. & Reg. Equip.-General	590,345	3.14%	18,537	18,537
379	Meas. & Reg. Equip.-City Gate	128,222	3.75%	4,808	4,808
380	Services	21,783,372	**7.17%**	1,561,868	1,561,868
381	Positive Meters	18,691,448	**3.10%**	579,435	579,435
383	Service Regulators	2,151,173	1.77%	38,076	38,076
385	Ind. Meas. & Reg. Station Eqpt.	187,825	3.31%	6,217	6,217
386.2	Other Property on Cust. Premise	148,673	0.27%	401	401
387.1	Cathodic Protection Equip.	1,175,058	3.21%	37,719	37,719
387.2	Other Distribution Equip.	117,422	0.99%	1,162	1,162
	Total Distribution Plant	$74,788,173		$2,700,615	$2,700,615
	General Plant				
389	Land	$7,131			
390	Structures and Improvements	449,416	3.46%	$15,550	$15,550
391.1	Furniture and Fixtures	48,359	8.33%	4,028	4,028
391.3	Computer Equip. - PC	51,081	20.00%	10,216	10,216
391.5	Computer Equip. - Other	14,561	20.00%	2,912	2,912
392.1	Trans. Equip., Non-Unitized	117,486	9.67% 2/		11,361
392.2	Trans. Equip., Unitized	2,325,417	0.26% 2/		6,046
393	Stores Equipment	14,254	2.86%	408	408
394.1	Tools,Shop&Gar. Eq.-Non-Un.	695,436	6.36%	44,230	44,230
394.3	Vehicle Maintenance Equip.	22,859	5.00%	1,143	1,143
395	Laboratory Equipment	32,303	7.11%	2,297	2,297
396.1	Power Operated Equip.	151,847	6.02% 2/		9,141
396.2	Work Equipment Trailers	1,963,501	0.23% 2/		4,516
397.1	Radio Comm. Equip.-Fixed	242,997	7.42%	18,030	18,030
397.2	Radio Comm. Equip.-Mobile	140,365	7.13%	10,008	10,008
398	Miscellaneous Equipment	15,109	7.87%	1,189	1,189
	Total General Plant	$6,292,122		$110,011	$141,075
303	Intangible Plant - General	$55,404	0.00% 3/	$0	$0

Acct. No	Account	Pro Forma Average Plant	Depreciation Rate	Annual Depreciation	Accumulated Reserve
	Common Plant				
389	Land	$988,648			
390	Structures and Improvements	7,005,825	**0.82%**	$57,448	$57,448
391.1	Furniture and Fixtures	539,419	7.61%	41,050	41,050
391.3	Computer Equip. - PC	420,753	9.76%	41,065	41,065
391.5	Computer Equip. - Other	11,912	20.00%	2,382	2,382
392.1	Trans. Equip., Non-Unitized	6,203	0.00% 3/		0
392.2	Trans. Equip., Unitized	618,075	4.11% 2/		25,403
392.3	Aircraft	483,574	3.77%	18,231	18,231
393	Stores Equipment	10,773	3.57%	385	385
394.1	Tools, Shop & Gar. Equip.	60,254	5.79%	3,489	3,489
394.3	Vehicle Maint. Equip.	44,545	5.59%	2,490	2,490
394.4	Vehicle Refueling Equip.	28,124	5.48%	1,541	1,541
397.1	Radio Comm. Equip.-Fixed	181,709	6.69%	12,156	12,156
397.2	Radio Comm. Equip.-Mobile	77,331	6.67%	5,158	5,158
397.3	General Tele. Comm. Equip.	105,405	10.00%	10,541	10,541
397.5	Supervisory & Tele. Equip.	223	6.69%	15	15
397.8	Network Equipment	60,492	20.00%	12,098	12,098
398	Miscellaneous Equipment	119,104	5.40%	6,432	6,432
	Total Common Plant	$10,762,369		$214,481	$239,884
303	Intangible Plant - Common	$5,456,184	4/	$442,126	$442,126
	CWIP in Service 5/				
	Distribution	$382,467	4.56%	$17,440	$17,440
	General	51,213	1.92%	983	983
	Common	67,043	2.94%	1,970	1,970
	Intangible - Common	(249)	2.95%	(7)	(7)
	Total CWIP	$500,474		$20,386	$20,386
	Total Gas Plant in Service	$100,963,935		$3,591,156	$3,647,623

1/ See Rule 38.5.123, Statement C, pages 3 - 5.
2/ Charged to a clearing account.
3/ Fully amortized/depreciated.
4/ Amortization based on the life of each item.
5/ Composite rates by function.

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER Of MONTANA- DAKOTA UTILITIES CO., a Division Of MDU Resources Group, Inc., for Authority to Establish Increased Rates For Natural Gas Service	)))))	REGULATORY DIVISION DOCKET NO. D2012.9.100

Pre-Filed Direct Testimony
of
George L. Donkin
on Behalf
of
The Montana Consumer Counsel

February 25, 2013

J.W. Wilson & Associates, Inc.
Economic Counsel
1601 North Kent Street · Rosslyn Plaza C · Suite 1104 Arlington, VA 22209

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I. IDENTIFICATION AND QUALIFICATIONS OF WITNESS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George L. Donkin. I am an economist employed by J.W. Wilson & Associates, Inc. My business address is 1601 North Kent Street, Arlington, VA, 22209.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. My appearance in this case is on behalf of the Montana Consumer Counsel (MCC).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold B.A. and M.A. degrees in economics from the University of Maryland, where my major fields of study were economic theory, industrial organization, and antitrust economics. I am a consulting economist specializing in energy economics and public policy toward business. I have more than forty years of experience in energy-related and public utility work, both as a consultant and as a staff economist at the Federal Power

Commission, the predecessor of the Federal Energy Regulatory Commission (FERC). Since 1974, I have been employed as a consulting economist representing various clients, including federal agencies, state regulatory commissions, state consumer advocate offices, public and private utility companies, industrial firms, natural gas producers, gas pipelines, gas distribution companies, gas marketers, and non-profit organizations. My professional work has pertained to a wide range of issues concerning the natural gas and petroleum industries, public utility regulation, energy policy, antitrust issues, and economic research and analysis. A special focus of my professional work has been the study of natural gas markets generally, and the analysis of price formation in both the regulated and unregulated sectors of the natural gas industry, in particular.

Q. HAVE YOU PREVIOUSLY PRESENTED EXPERT TESTIMONY IN PROCEEDINGS INVOLVING THE NATURAL GAS AND OIL INDUSTRIES?

A. Yes. I have presented expert testimony on natural gas and oil industry topics in more than one hundred-fifty proceedings before numerous state and federal courts, before the FERC, before the Surface Transportation

Board, and before various state public utility commissions. I have also testified as a natural gas expert in arbitration proceedings in Louisiana, New Mexico and Texas, before a Mediator in Ohio, and in Federal tax and bankruptcy courts. Attachment A contains a listing of my prior expert testimony.

Q. HAVE YOU PREVIOUSLY PRESENTED EXPERT TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION?

A. Yes. As is shown in Attachment A, I have presented expert testimony before this Commission in numerous proceedings, several of which involved the Montana-Dakota Utilities Company (MDU or the Company).

II. INTRODUCTION

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

A. This case involves MDU's September 26, 2012, general rate case filing, and related natural gas cost allocation and rate design proposals. I have been asked by the MCC to analyze the Company's cost allocation and rate design proposals, including the Company's request that the Commission approve its proposed Distribution Delivery Stabilization Mechanism

(DDSM), and to present the results of my analysis to the Commission in the form of pre-filed direct testimony and related exhibits.

Q. IS MDU SEEKING AN INCREASE IN ITS GAS SUPPLY COSTS IN THIS CASE?

A. MDU's application does not address the level of traditional gas supply costs the Company recovers from its sales customers. MDU uses gas tracker filings to recover the costs it pays to gas suppliers and gas pipelines. This case does, however, include MDU's request to recover the costs of a non-traditional gas supply source – the Company's Billings Landfill methane project. That issue is addressed in the pre-filed direct testimony of MCC witness Albert E. Clark. With that exception, the issues in this case only involve the non-gas costs and related non-gas revenue requirement that MDU incurs in providing natural gas delivery service to the Company's Montana ratepayers.

Q. HAS MDU PRESENTED BOTH EMBEDDED AND MARGINAL COST STUDIES IN THIS CASE?

A. Yes. MDU's cost allocation and rate design witness in this case is Tamie A. Aberle. Ms. Aberle's pre-filed direct testimony contains both an

embedded cost of service study and a marginal cost study. For simplicity I will refer to embedded cost of service as ECOS.

Q. PLEASE DESCRIBE HOW ECOS STUDIES ARE USED IN GAS UTILITY RATEMAKING.

A. An ECOS study is based on the total costs of service that a gas utility has incurred over time. It is a calculation of a gas utility's historical costs, including all of the costs used to support the allowed revenue requirement, and these costs are distributed or allocated to customer classes based on cost incurrence or cost responsibility considerations. Because the provision of gas utility service is largely a supply of joint services, with all or nearly all of the customers using the system all or nearly all of the time, ECOS analysis represents an attempt to allocate among rate classes the joint costs that a gas utility incurs in providing gas utility services to all of its customers.

Q. IS THERE WIDESPREAD ACCEPTANCE OF THE USEFULNESS OF ECOS STUDIES IN THE NATURAL GAS RATEMAKING PROCESS?

A. Yes. Most gas utility analysts and regulators believe that gas utility rates should reasonably reflect the costs of providing gas utility service. Because a gas utility's allowed revenue requirement is based on its historical embedded costs, ECOS studies are commonly used to estimate customer class costs and as a guide in setting customer class annual revenue requirements.

Q. ARE MARGINAL COST STUDIES COMMONLY USED FOR THIS SAME PURPOSE?

A. No. Although marginal cost analysis may be relevant for assigning cost responsibility for gas supply costs, marginal cost studies have little or no value in assigning customer class cost and revenue responsibility for the historical or embedded non-gas costs that are on the accounting books of a regulated gas utility like MDU.

Q. WHY IS THAT?

A. Nearly all of a gas utility's embedded non-gas costs are fixed in the short run, and they typically reflect only moderate changes over time. This means that the estimated marginal non-gas cost of meeting incremental customer demands on either a peak day or average day are minimal, in relation to total embedded non-gas costs. See, e.g., Energy West Montana, Docket D2010.9.90, Final Order No. 7132c, at Par. 120, dated November 18, 2011, where the Commission stated:

- Marginal cost pricing to recover embedded distribution costs is highly problematic, and probably not workable; and
- The short-run marginal cost of distribution is generally accepted to be close to zero, but the long-run cost of distribution is not known, and may be significantly greater than zero.

Thus, using estimates of marginal non-gas costs to assign customer class cost and revenue responsibility nearly always produces total revenues that fall far short of the gas utility's total allowed revenue requirement. Accordingly, ECOS studies are greatly preferred to marginal cost studies

for estimating customer class non-gas cost and revenue responsibility in the regulated natural gas utility industry.

Q. HAS THAT BEEN THE CASE IN MONTANA IN RECENT YEARS?

A. Yes. For example, in Docket D2009.9.129/D2007.7.82, NorthWestern Energy (NWE) presented both ECOS and marginal cost studies, but recommended that only its ECOS study be used in that case and in future NWE general rate cases to estimate customer class non-gas costs and as a guide in establishing customer class revenue responsibility. The parties to that case, including the MCC, agreed with NWE's recommendation on the use of class cost of service studies, and on September 20, 2010, they submitted to the Commission a Stipulation and Settlement Agreement that provided the following:

> The Parties agree that embedded cost studies rather than marginal cost studies, should be used for electric and natural gas delivery services for this docket. The Parties also agree that the embedded cost models filed by NorthWestern and used by the Parties in this Docket are acceptable for future use, recognizing that there are differences of opinion regarding the various inputs and class

allocators within the models. (Par. 8.A., September 20, 2010 Stipulation and Agreement, in Docket D2009.9.129/D2007.7.82)

Q. WAS THAT STIPULATION AND AGREEMENT APPROVED BY THE COMMISSION?

A. Yes; by Order No. 7046h, dated December 9, 2010.

Q. HAS THE EXCLUSIVE USE OF ECOS STUDIES BEEN THE BASIS FOR ESTIMATING NON-GAS CUSTOMER CLASS COSTS IN SUBSEQUENT NATURAL GAS RATE CASE FILINGS BEFORE THE COMMISSIION?

A. Yes. In Energy West Montana, Docket No. D2010.9.90, both EWM and I, on behalf of the MCC, submitted only ECOS studies to support our class cost and revenue responsibility recommendations. Similarly, in NorthWestern Energy, Docket No. D2012.9.94, both NWE and I, again on behalf of the MCC, submitted only ECOS studies for the same purposes.

Q. WHAT METHODOLOGY HAS MDU USED TO DISTRIBUTE ITS PROPOSED NON-GAS REVENUE INCREASE IN THIS CASE?

A. At page 13 of her pre-filed direct testimony, Ms. Aberle states that she "primarily used" her ECOS study as a guide in developing MDU's proposed additional revenue requirements for the various customer classes.

Q. DO YOU AGREE THAT AN ECOS METHODOLOGY CAN BE A USEFUL GUIDE FOR DISTRIBUTING TO CUSTOMER CLASSES THE ALLOWED REVENUE REQUIREMENT THAT MDU IS TO BE AWARDED IN THIS CASE?

A. While I do not agree with several of the class allocators Ms. Aberle uses in her ECOS analysis, I do agree that ECOS analysis is appropriate for evaluating customer class cost and revenue responsibility for non-gas delivery service on MDU's Montana system.

Q. SHOULD THE COMMISSION RELY ON MDU'S MARGINAL COST STUDY IN ITS EVALUATION OF THE CLASS COST OF SERVICE AND RATE DESIGN ISSUES IN THIS CASE?

A. No. The marginal cost studies performed by the Company and presented in the pre-filed direct testimony of Ms. Aberle should be ignored by the

Commission in its evaluation of the non-gas cost and revenue responsibility issues in this case.

Both the Company and I recommend that our respective ECOS studies be used as a guide to apportion customer class cost and revenue responsibility in this case.

III. PRINCIPLES OF NATURAL GAS ECOS ANALYSIS AND RATE DESIGN

Q. ARE THERE PRINCIPLES, THEORETICAL CONCEPTS, AND PRACTICAL CONSIDERATIONS THAT ARE FREQUENTLY APPLIED TO NATURAL GAS ECOS AND RATE DESIGN ANALYSIS?

A. Yes. Although differences of opinion exist as to which considerations should receive primary emphasis, there is general agreement that gas utility rates should be structured and designed to promote the following objectives:

(1) Conservation of resources supplied by gas utilities;

(2) An economically efficient use of facilities and resources by gas utility systems and their customers;

(3) Equity in the rates charged to gas consumers. Equity in this context means similar treatment for similar customers or service, and different treatment for different customers or service;

(4) Revenue and earnings stability. Rate structures should provide gas utilities with a reasonable opportunity to recover their allowed cost of service;

(5) Adequate incentives for gas utility management to control costs;

(6) Rate continuity, with moderate changes generally being preferred to dramatic or radical departures from present rate structures, rate levels, and class revenues; and

(7) Understandability and customer acceptance.

These objectives can conflict with each other. For example, low fixed service or customer charges that do not vary with the level of gas consumed require higher "commodity" or "delivery" rates. This type of natural gas rate structure will best promote conservation of resources and economically efficient end-use consumption decisions. But lower customer or service

charges and therefore higher commodity rates tend to subject a gas utility to somewhat greater revenue and earnings instability if heating season temperatures are significantly warmer or colder than the normal temperatures that were used to produce the design commodity rates that were approved in the utility's last rate case. Similarly, higher fixed service charges can be used to achieve greater revenue and earnings stability, but this approach conflicts with the objectives of promoting customer acceptance, equity, and economic efficiency.

Q. IS THERE ALSO WIDESPREAD ACCEPTANCE OF A BASIC METHODOLOGY FOR PREPARING CLASS COST OF SERVICE STUDIES?

A. There is no universally accepted methodology for preparing class cost of service studies for gas utilities. As a result, ECOS studies frequently vary among gas utilities and regulatory jurisdictions. Also, the procedures used in developing class cost of service studies are sometimes modified as market conditions in the gas utility industry change over time.

Q. ARE THERE NEVERTHELESS SOME SIMILARITIES IN MOST ECOS STUDY METHODOLOGIES?

A. Yes. Most ECOS studies make distinctions between variable costs and fixed costs. Variable costs, which in the short run are largely the costs of purchased gas and other related gas supply expenses, are almost always allocated among customers on the basis of their respective annual usage. Fixed costs, many of which relate to the capacity to deliver gas, can be allocated among customers in a number of different ways. However, the following factors are often observed as a basis for allocating fixed capacity-related gas utility costs:

(1) Peak-period or peak-day usage levels;

(2) Seasonal usage levels; and

(3) Annual usage levels.

A combination of the above factors can, and in my view, should be used in allocating a gas utility's fixed capacity-related costs among customers or customer classes.

Q. WHY IS THAT?

A. Natural gas transmission and distribution pipelines would never be built to only serve peak day or design day gas demands; they exist to provide gas delivery service throughout the year. This fundamental principle was the foundation for the FPC's 1952 Atlantic-Seaboard decision. There, the FPC stated:

> We are unable, however, to accept the premise that merely because certain costs do not vary with use they automatically become in toto demand or capacity costs. A pipeline would not normally be built to supply peak service, that is to say, service on peak days only. ... pipelines are built to supply service not only on the few peak days but on all days throughout the year. In providing the economic feasibility of the project in certificate proceedings, reliance is placed upon the annual as well as the peak deliveries. Stated another way, the capital outlay for the pipeline facility is made -- and justified -- not only for service on the peak days but for service throughout the year. Both capacity and volume, therefore, are what are known as cost factors or incidences in respect to the capital outlay for a pipeline project. It follows that reasonably accurate results can be achieved only by allocating the fixed expenses flowing from the capital outlay to both operating functions, viz., capacity and volume. [Atlantic Seaboard Corp., et al. 11 FPC 43 (1952).]

Q. DO SOME OF THE COSTS OF GAS UTILITY SERVICE VARY PRIMARILY WITH THE NUMBER OF CUSTOMERS BEING SERVED?

A. Yes. These are what are known as customer-related costs. They primarily include meter reading expenses, customer records and collection expenses, and miscellaneous customer-related expenses. Because these kinds of costs tend to vary with the number of customers being served, they are usually allocated in ECOS studies on the basis of customer counts.

Q. SHOULD CUSTOMER CLASS REVENUES BE SET EQUAL TO THE CUSTOMER CLASS COST ESTIMATES IN A PARTICULAR ECOS STUDY?

A. No. It has long been recognized by rate analysts and regulators that while shifting class revenues in the direction of estimated embedded costs for delivery services may be desirable, moderate changes from one case to another are usually preferred to large or dramatic changes.

IV. ECOS AND RATE DESIGN ISSUES IN THIS CASE

Q. YOU STATED PREVIOUSLY THAT YOU DISAGREE WITH CERTAIN ASPECTS OF MS. ABERLE'S ECOS STUDY.

A. I disagree with how Ms. Aberle's ECOS study classifies and allocates the costs of MDU's Distribution Mains system, Services and related costs, Meters and related costs, and A&G expenses. Ms. Aberle classifies and allocates the costs of MDU's Distribution Mains pipelines entirely on the basis of customer class peak day demands. This ignores the fact that MDU's Distribution Mains pipelines never would have been built if their sole purpose was to serve customer demands on a single peak day. Indeed, it is far more accurate to say that the main purpose of MDU's Distribution pipelines is to meet its customers' annual Dkt throughput requirements. Customer class annual Dkt volumes therefore represent an equally important functional basis for the embedded costs of the Company's integrated Distribution Mains pipeline system. Accordingly, a significant portion of the costs of MDU's Distribution Mains pipelines should be classified and allocated to customer classes on the basis of both peak day Dkt volumes and annual Dkt volumes.

Q. WHAT IS THE BASIS FOR YOUR DISAGREEMENT WITH HOW MS. ABERLE ALLOCATES THE COSTS OF SERVICES AND METERS IN HER ECOS STUDY?

A. Services costs are the costs of the pipelines that move gas from the Company's distribution mains to its customers' premises. Meter costs are the costs of the meters that measure the Dkt quantities that NWE delivers to individual customers' premises throughout the Company's Montana system. Ms. Aberle classifies Services and Meters as entirely customer-related, and she uses customer counts to allocate MDU's functionalized Services and Meters costs. This is in sharp conflict with the Montana Commission's most recent pronouncement on how the costs of Services and Meters should be allocated to customer classes in a natural gas ECOS study. To illustrate, on November 18, 2011, in Energy West Montana, Docket No. D2010.9.90, Order No. 7132c, at p. 24, the Commission stated:

> "Nor is the Commission convinced that a 100% customer-related classification of services and meters is reasonable. Some portion of service and meter costs should be classified capacity-related."

Q. CAN YOU SHOW BY WAY OF EXAMPLES WHY THE COSTS OF MDU'S DISTRIBUTION PIPELINES SHOULD BE CLASSIFIED AND ALLOCATED TO CUSTOMERS ON THE BASIS OF BOTH DESIGN DAY AND ANNUAL DKT VOLUMES?

A. Yes. MDU's revised peak day demand at Distribution is 95,687 Dkt. Thus the Company needs a Distribution pipeline system capable of delivering at least 95,687 Dkt to its customers on any given day. MDU's pro forma annual throughput at Distribution in this case, is 12,268,927 Dkt; that represents an average daily throughput of 33,613 Dkt. If there were no variation over the course of the year in daily throughput, MDU's Distribution pipeline system would require a peak day delivery capacity of at least 33,613 Dkt. This demonstrates that some portion of MDU's functionalized Distribution Mains costs is related to average annual daily usage, and some of those same costs are related to the delivery of gas volumes when system demands are greater than average annual daily usage.

Q. ARE THERE ADDITIONAL REASONS WHY THE COSTS OF MDU'S DISTRIBUTION MAINS PIPELINES SHOULD NOT BE ALLOCATED TO CUSTOMER CLASSES ENTIRELY ON THE BASIS OF PEAK DAY DEMANDS?

A. Yes. All else equal, large diameter gas pipelines can deliver more gas on any given day than small pipelines, and large-diameter pipe costs more than small-diameter pipe. However, many of the costs of gas pipelines do not vary much, if at all, in relation to alternative pipe size distinctions. These kinds of costs include:

- Excavation costs;
- The costs of stringing pipe;
- Right-of-way costs;
- Inspection costs;
- Costs of replacing sidewalks and paved roads;
- Surveying costs;
- Costs of preparing pipe beds; and

- Costs of obtaining environmental approvals; when applicable.

Because many costs do not increase as pipe size increases, total gas pipeline costs do not increase on a one-to-one ratio when gas demands on the pipeline system increase. Furthermore, the throughput capacity of gas pipelines does not increase on a one-to-one ratio with the diameter size of pipe; rather, throughput capacity increases by the square of pipeline diameter size. Consequently, the delivery capacity of an 8-inch gas pipeline is four times greater than the capacity of a 4-inch gas pipeline. This means the added costs of increasing capacity are usually lower than the average costs of providing total capacity. It also means that the unit cost of providing capacity to move average demands is higher than the unit cost of providing capacity for increased demands. When these considerations are taken into account, it is clear that a combination of peak day and annual usage should be used in allocating the costs of MDU's Distribution Mains pipeline system.

Q. HAVE YOU DONE THAT IN YOUR ECOS STUDY?

A. Yes. In performing my ECOS study, I allocated the costs of MDUs Distribution Mains pipelines and Mains-related costs on the basis of 50% peak day Dkt volumes, and 50% annual throughput Dkt volumes.

Q. HOW DID YOU ALLOCATE THE COSTS RELATED TO MDU'S SERVICE PIPELINES AND METERS IN YOUR ECOS STUDY?

A. In performing my ECOS study, I allocated the costs related to MDU's Services, Service Regulators, and Meters on the basis of 50% peak day Dkt volumes, and 50% number of customers.

Q. DID YOU MAKE OTHER CHANGES TO MDU'S ECOS STUDY IN PERFORMING YOUR OWN ECOS ANALYSIS?

A. Yes. MDU's study allocates Administration & General (A&G) expenses on the basis of operation & maintenance expenses, excluding cost of gas supplies. This is not a good allocator for A&G expenses. Much of the Company's A&G expenses are incurred as overheads associated with running a regulated natural gas utility business. These activities include but are not limited to the following:

- Preparing and participating in periodic general rate case filings;
- Preparing regular monthly regulatory filings;
- Preparing regular quarterly and/or annual reports to regulators and investors;
- Analyzing daily, monthly, annual, and expected future gas supply demand and supply requirements;
- Scheduling gas supplies into and out of the Company's contract gas storage resources;
- Negotiating and administering gas supplier contracts;
- Gas supply portfolio planning;
- Monitoring and participating in pipeline supplier regulatory proceedings; and
- Other overheads associated with financial and/or accounting activities.

In my judgment, much of MDU's business activities and related A&G expenses are incurred in connection with the Company's daily, monthly, seasonal, and annual gas supply and demand activities, not with the O&M expenses that are incurred to provide for the physical delivery of gas to

customers. I therefore allocated MDU's A&G expenses on the basis of peak day Dkt demands (50%) and annual Dkt demands (50%).

Q. HOW DO THE RESULTS OF YOUR ECOS STUDY COMPARE WITH THE RESULTS OF MDU'S STUDY?

A. The results of Ms. Aberle's ECOS study are presented at Statement L, Schedule L-1. At MDU's claimed cost of service, the Company's pro forma non-gas revenues at present rates amount to $20,068,442. This produces a claimed overall total Montana rate of return (ROR) of 3.720%. The results of my ECOS study are summarized and presented in Exhibit ___ (GLD-1). My ECOS study used the same total cost of service and total pro forma non-gas revenues at present rates - $20,068,442 – that was used by Ms. Aberle. The individual customer class RORs resulting from Ms. Aberle's ECOS study and from my ECOS study are as follows:

	Statement L	Exhibit GLD-1
Residential	0.728%	5.307%
Small Firm General	11.364%	12.958%
Large Firm General	7.444%	7.858%

Small Interruptible	40.315%	6.566%
Large Interruptible	13.934%	-26.367%
Total MDU Montana	3.720%	3.718%

Q. HOW HAS MS. ABERLE DISTRIBUTED THE COMPANY'S PROPOSED REVENUE INCREASE TO MDU'S CUSTOMER CLASSES?

A. MDU is requesting a total Montana revenue increase of $3,457,412. My Exhibit ___ (GLD-2) summarizes how the Company is proposing to distribute its requested total increase to its Montana customer classes. As shown there, MDU's proposal would produce the following total revenue increases and percentage increases in non-gas revenues for its various customer classes:

	Total Increase	% Increase
Residential	$2,836,325	23.2%
General Service	$594,426	9.1%
Small Interruptible	$19,161	2.5%

Large Interruptible	$7,500	1.4%
Total Montana	$3,457,412	17.2%

Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS FOR HOW A REVENUE INCREASE AWARDED TO MDU IN THIS CASE SHOULD BE DISTRIBUTED TO THE COMPANY'S MONTANA CUSTOMER CLASSES?

A. Yes. My alternative recommendations for how to distribute to customer classes an increase in total revenues resulting from this case are presented in Exhibit ___ (GLD-3).

Q. PLEASE DESCRIBE WHAT IS PRESENTED IN EXHIBIT ___ (GLD-3).

A. MDU's proposed distribution to customer classes of its requested total revenue increase of nearly $3.5 million (a 17.23% increase) is presented at lines 1 – 7 of Exhibit ___ (GLD-3). The percentage increases being proposed by MDU for individual customer classes vary over a wide range, e.g., 23.22% for Residential service, but only 1.37% for Large Interruptible service.

Q. IS MDU'S PROPOSED APPORTIONMENT TO CUSTOMER CLASSES OF ITS REQUESTED REVENUE INCREASE CONSISTENT WITH THE CLASS RORs THAT RESULT FROM YOUR ECOS STUDY?

A. No. For example, whereas MDU is proposing a very small percentage revenue increase (1.4%) for the Large Interruptible class, my ECOS study produces a negative 26.37% ROR for Large Interruptible service. At the same time MDU is proposing much larger percentage increases in revenues for its other customer classes, each of which is producing a ROR in my ECOS study that is above the total company-wide ROR. This is especially so for the Residential customer class – a 5.31% ROR and MDU-proposed revenue increase of 23.22%.

Q. HOW SHOULD CLASS NON-GAS REVENUES BE SET IN THIS CASE IF THE COMMISSION ACCEPTS 100% OF MDU'S REQUESTED REVENUE INCREASE?

A. My Exhibit ___ (GLD-3) presents MCC's recommended class revenues under alternative total Company revenue outcomes from this case. For comparison purposes, at lines 1-7 of the exhibit, I show MDU's proposed class revenues at the Company's claimed total revenue requirement.

MCC's recommended class revenues if the Commission were to award 100% of the Company's requested total revenue increase is presented at lines 8–14 of Exhibit ___ (GLD-3). In developing the proposed class revenue increases shown there, I took into account the fact that my ECOS study shows a large negative ROR for the Large Interruptible class, positive RORs that are above the company-wide average ROR for each of the other classes, and relatively small differences in the estimated RORs for the Residential, Large Firm General Service, and Small Interruptible customer classes. My recommendation results in a 27.4% increase for the Large Interruptible class, a 16.5% increase for the Small Firm General Service class, and an equal 17.0% increase for each of MDU's other customer classes. This recommendation, if adopted, would move the estimated ROR for each of MDU's customer classes in the direction of the system average ROR, without producing a dramatic change in the relative RORs among the customer classes.

Q. HOW SHOULD CUSTOMER CLASS REVENUES BE DETERMINED IN THIS CASE IF THE COMMISSION ADOPTS MCC'S PROPOSED REVENUE REQUIREMENT?

A. MCC's witness Mr. Clark is recommending that MDU be awarded a total revenue increase in this case of $421,966. My recommended distribution to MDU's firm customer classes if the Commission accepts Mr. Clark's total revenue requirement recommendation is presented at lines 15 – 20 of Exhibit ___ (GLD-3).

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE INCREASES IN CUSTOMER CLASS REVENUES THAT YOU RECOMMEND IF THE COMMISSION ADOPTS MCC'S PROPOSED REVENUE REQUIREMENT IN THIS CASE.

A. MDU's proposed total non-gas revenue requirement in this case is 17.23% greater than its total non-gas revenues at present rates. MCC's proposed total revenue increase of $421,966 is 2.10% greater than MDU's total revenue at present rates. The ratio of 2.10 % to 17.23% is 12.20%. I multiplied that figure – 12.20% - by the customer class percentage increases at Lines 8 – 13 of Exhibit ___ (GLD-3), to arrive at the

percentage increases for each customer class that appear at Lines 15 – 20 of Exhibit ___ (GLD-3).

Q. CAN THE "SCALE-BACK" PROCEDURE YOU JUST DESCRIBED BE USED FOR ANY GIVEN LEVEL OF REVENUE INCREASE THE COMMISSION MAY APPROVE IN THIS CASE?

A. Yes. The "scale-back" procedure used in preparing Exhibit _ (GLD-3) maintains the relative proportions of customer class increases that I am recommending for any given level of revenue increase that the Commission ultimately awards in this case. If the Commission awards a $1.0 million revenue increase, that would represent about a 5.0% increase from the Company's total non-gas revenues at present rates. The ratio of 5.0% to 17.23% (29.0%) can then be applied to the percentage increases in customer class revenues that I am recommending at Lines 8 – 13 of Exhibit ___ (GLD-3); thereby producing MCC's recommended customer class revenues and percentage increases at a total company non-gas revenue requirement level that is somewhat greater than that which MCC is recommending in this case.

V. MDU'S RESIDENTIAL SERVICE CHARGES

Q. SHOULD MDU'S FIXED MONTHLY RESIDENTIAL SERVICE CHARGES BE INCREASED IN THIS CASE, AS MS. ABERLE HAS PROPOSED?

A. No. Ms. Aberle is proposing a very large - 67.6% - increase in the Residential service charge, from $6.35 per month to $10.64 per month. This recommendation – if approved by the Commission – would produce significantly different impacts on the total delivery charges of individual Residential gas customers on MDU's Montana system. In particular, small-volume Residential customers would bear a much greater share of any change in Residential class revenues resulting from this case. This is demonstrated in Exhibit ___ (GLD-4), which shows at alternative annual gas usage levels how annual Residential non-gas delivery charges would be affected by MDU's proposed increase in the Residential service charge. As shown there, a Residential customer with annual gas usage of 35 Dkt would experience a 40.7% increase in annual non-gas delivery charges if MDU's proposed service charge is approved, while a Residential customer with annual usage of 175 Dkt would experience only a 10.7% increase in annual delivery charges at MDU's proposed Residential service charge.

Q. CONVERSELY, YOUR EXHIBIT ___ (GLD-4) SHOWS THAT SMALL-VOLUME RESIDENTIAL CUSTOMERS WILL EXPERIENCE LOWER PERCENTAGE INCREASES IN THEIR TOTAL ANNUAL NON-GAS DELIVERY CHARGES THAN LARGE-VOLUME RESIDENTIAL CUSTOMERS IF THE MONTHLY SERVICE CHARGE IS KEPT AT THE PRESENT LEVEL. IS THAT A GOOD RESULT?

A. Yes. There are several reasons for why that is a good result. First, a lower service charge coupled with somewhat higher commodity rates for larger levels of consumption will send better price signals to all Residential gas customers, and this would be especially so for larger Residential consumers, i.e. those using 100 Dkt or more per year. Furthermore, as is shown in MDU's response to Data Request MCC-121, 49.1% of MDU's Residential customers use less than 71 Dkt per year, 68.7% use less than 91 Dkt per year, and only 17.4% use over 110 Dkt per year. Thus, a much larger number of Residential customers would be adversely affected than those who would benefit if MDU's proposed increase in the Residential service charge is adopted. Keeping the fixed monthly customer charge at its present level is also consistent with the level of customer-related O&M expenses that MDU incurs in providing Residential gas service. Lastly, the

customer acceptance consideration also supports keeping the fixed Residential service charge at its present level. Residential gas consumers simply find it difficult to understand why their gas bills remain relatively high, especially in shoulder months, even though their gas consumption may have declined significantly.

Q. IN YOUR LAST RESPONSE YOU STATED THAT KEEPING THE RESIDENTIAL SERVICE CHARGE AT THE PRESENT LEVEL IS CONSISTENT WITH THE LEVEL OF CUSTOMER-RELATED O&M EXPENSES MDU INCURS IN PROVIDING RESIDENTIAL GAS SERVICE. WHAT IS THE BASIS FOR THAT STATEMENT?

A. MDU's present Residential service charge of $6.35 is significantly greater than the level of customer-related O& M expenses the Company has been incurring in recent years on a per customer basis. My Exhibit ___ (GLD-5) presents a summary of MDU's annual customer-related O&M expenses, average number of customers, and average monthly customer-related O&M expenses in calendar years 2007 – 2011. As shown there, MDU's present Residential service charge of $6.35 per month is significantly greater than the per customer average monthly customer-related O&M expenses the Company incurred each year during 2007 – 2011, i.e., a range of $3.75 per

month in 2008, down to $3.14 per month in 2011. I therefore recommend that MDU's present monthly Residential service charge be kept at $6.35 per month. If, however, the Commission determines that some increase in the Residential service charge is appropriate, I recommend that any such increase be limited to the percentage increase in the Company's total annual revenue requirement that results from this case. This would produce a Residential service charge of $6.48 if MCC's recommended non-gas revenue increase in this case of 2.10% is adopted by the Commission.

VI. MDU'S PROPOSED DISTRIBUTION DELIVERY STABILIZATION MECHANISM

Q. MDU IS ASKING THE COMMISSION TO APPROVE ITS PROPOSED DDSM. WHAT IS THE STATED PURPOSE OF THE DDSM BEING PROPOSED BY MDU IN THIS CASE?

A. MDU's proposed DDSM is described in the pre-filed direct testimony of Ms. Aberle. At page 20, lines 3-5 of her testimony, Ms. Aberle states that the purpose of the proposed DDSM is to "minimize the impact of weather on Montana-Dakota's financial condition and on the volatility of customers' gas bills."

Q. WHAT IS YOUR UNDERSTANDING OF HOW THE PROPOSED DDSM WOULD WORK, AS PROPOSED AND IF APPROVED BY THE COMMISSION?

A. As described by Ms. Aberle, the proposed DDSM would only apply to the Company's Residential (Rate Schedule 60) and Firm General Service (Rate Schedule 70) customers. MDU would compute DDSM positive or negative surcharges during the months of November 1 through May 1, so as to recover the non-gas margins at normal temperatures that were approved for that service in its last general rate case.

Q. HAS THE COMMISSION RECENTLY ADDRESSED LOST REVENUE ADJUSTMENT MECHANISMS IN ANOTHER GENERAL RATE CASE?

A. Yes. In NorthWestern Energy, Docket Nos. D2009.9.129 and D2007.7.82, a witness for the District XI Human Resource Council and Natural Resources Defense Council introduced and testified in support of a lost revenue "decoupling" proposal. That proposal was then supported by NWE, to be implemented as a pilot project.

Q. DID THE COMMISSION APPROVE THE REVENUE DECOUPLING PROPOSALS THAT WERE PRESENTED IN THAT CASE?

A. No. In Order No. 7046i, dated June 30, 2011, the Commission declined to approve the revenue decoupling mechanisms that were being proposed in that case.

Q. SHOULD THE COMMISSION APPROVE MDU'S PROPOSED DDSM IN THIS CASE?

A. No. There are several reasons why MDU's proposed DDSM should not be approved. They include the following:

- The proposed DDSM is a single-issue ratemaking device that can produce periodic rate increases without taking into account other factors that would support no rate change, or even a rate reduction. For example, growth in the number of customers continues to take place on the MDU system, and customer growth will be experienced between rate cases, including periods of time when warmer than normal temperatures result in reduced gas usage. With the proposed DDSM the Company would collect increased margins caused by

lower sales due to weather, but at the same time it also would collect increased margin revenues resulting from growth in the number of customers served. The increased margins resulting from customer growth would not be recognized and taken into account in the calculation of the DDSM rate increase. In my judgment single-issue ratemaking mechanisms like MDU's proposed DDSM should be avoided.

- If approved, MDU's proposed DDSM would distort price signals to the Company's Residential and General Service ratepayers. This is because increases or decreases in rates in subsequent time periods to reflect warmer or colder than normal temperatures in prior time periods would produce rates that exceed or fall short of actual costs.

- The proposed DDSM also would reduce MDU's business risk, relative to the business risk that likely was used by the Commission in arriving at the cost of capital associated with the Company's investments in gas utility operations.

Q. DOES THIS COMPLETE YOUR PRE-FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

ATTACHMENT A

PRIOR EXPERT TESTIMONY
OF GEORGE L. DONKIN

Item	Jurisdiction	Lead Case/ Docket No.	Case Title	Issue Codes*/
1.	Federal Court (New York)	CV75C208	Counties of Suffolk, et al. v. Department of Interior	j, k
2.	Federal Court (District of Columbia)	CV79-1633	Energy Action, et al. v. Cecil D. Andrews, et al.	i, j
3.	Federal Court (New Mexico)	MDL403	In Re New Mexico Natural Gas Antitrust Litigation	g, h, i
4.	Federal Court (Colorado)	MDL403	In Re New Mexico Natural Gas Antitrust Litigation	g, h, i
5.	Federal Court (New Mexico)	CV81-036	City of Farmington v. Amoco Gas Company	b, h
6.	Federal Court (Pennsylvania)	CV85-1514	Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Commission	e, h
7.	Federal Court (New Mexico)	CV85-2550	Sheilah Brewer, et al. v. Consolidated Oil & Gas, Inc.	g, h, i
8.	Federal Court (W. Texas)	MO-87-CA-312	JJ-CC, Limited, et al. v. Transwestern Pipeline Company	b, h
9.	Federal Court (W. Texas)	MO-87-CA-313	Doyle Hartman v. Burlington Northern, Inc., et al.	a, f, h, i, p

*/ See description of Issue Codes at page 13.

10.	Federal Court (N. Texas)	CA-87-0219-D	Southern Union Exploration Co. v. Public Service Co. of New Mexico	g, h, i
11.	Federal Court (New Mexico)	CIV-88-0519-5C	Public Service Co. of New Mexico, et al., v. Meridian Oil Company	g, h, i
12.	Federal Court (New Mexico)	CIV89-02115C	Sunterra Gas Gathering Co. v. El Paso Natural Gas Co.	a, f, h
13.	Federal Court (Kansas)	85-2349	In Re Wyoming Tight Sands Antitrust Cases	a, f, g, h, i
14.	Federal Court (Ohio)	C2-85-1209	Enterprise Energy Corp., et al., v. Columbia Gas Transmission Corp.	f, h
15.	Federal Court (Texas)	89-0072	New Bremen Corp. v. Columbia Gas Transmission Corp.	f, h
16.	Federal Court (Wyoming)	86-0172	Amoco Rocmount Co., et al. v. The Anschutz Corp.	e, g
17.	Federal Court (N. Oklahoma)	92-C-649E	Windward Energy & Marketing Co. v. El Paso Natural Gas Co. et al.	i, j, p
18.	Federal Court (N. Dis. WV)	93-0009-W(S)	Cameron Gas Co., et al., v. Allegheny & Western Resources Corp., et al.	i, j
19.	Federal Court (N. Dis. CA)	C94-0911 VRW	Norcen Energy Resources Ltd., et al. v. Pacific Gas and Electric Co., et al.	c, e, d, p
20.	Federal Court (New Mexico)	95-0012-JC/WWD	Doris Feerer, et al., v. Amoco Prod. Co., et al.	b, e, i, p
21.	Federal Court (Texas)	CA-H97-2126	EPEC Gas Latin America, Inc., et al. v. Intratec S.A. de C.V., et al.	h, i

22.	Federal Court (Colorado)	96-Z-2451	U.S. Government, et al., v. Shell Oil Co., et al.	a, c, h
23.	Federal Court (Nevada)	MDL No. 1566	Learjet Inc. v. Oneok Inc. et al.	e, i, m
24.	Federal Court (New Mexico)	CIV-06-00624 MCA/RLP	Malcolm Smithson, et al. v. Hess Corp	r
25.	Federal Court (Delaware - Ch. 11)	91-803 & 91-804	Columbia Gas System, Inc. and Columbia Gas Transmission Corp.	h, j
26.	Federal Court (Delaware - Ch. 11)	91-803, 91-804, & M-93-276	Columbia Gas System, Inc. and Columbia Gas Transmission Corp.	e, l, j
27.	Federal Court (Delaware - Ch. 11)	91-804	Columbia Gas Transmission Corp.	h, k
28.	Federal Court (PA - Ch. 11)	05-94-01486	Continental Energy Associates Limited Partnership	a, h, j
29.	Federal Court (Maryland)	DKC 08 CU0967	Washington Gas Light Co. v. PG County	a, h
30.	U.S. Tax Court	5295-91	Pacific Enterprises and Subsidiaries v. IRS	a, b, j, q
31.	New Mexico State Court	SF79-1523	Cotton Petroleum Company v. State of New Mexico	a, h
32.	New Mexico State Court	CV90-759-4	Northern Trust Co. v. El Paso Natural Gas Company	b, g
33.	New Mexico State Court	SF94-1982(C)	Bank One, Texas N.A., et al. v. Meridian Oil, Inc., et al.	h, k, j
34.	New Mexico State Court	D-0101-CV-2000	Ray Powell, Commissioner of Public Lands v. Amoco Production Co., et al.	r, p

35.	New Mexico State Court	D-818-CV-2004-00026	J.Casper Heimann et al.,v. Kinder-Morgan Co[2] Company, L.P.	r, p
36.	New Mexico State Court	04-24 CV	Jay D. Heimann, et al., v. Oxy USA, Inc.	r, p
37.	New Mexico State Court	D-0101-CV-2004-01459	Patrick H. Lyons, Commissioner of Public Lands v. Oxy USA, Inc	r, p
38.	New Mexico State Court	CV 2004-26	R.G. Heimann, et al., v. Kinder-Morgan	r
39.	New Mexico State Court	05-48 CV	Marguerite Annie Poling et.al. v. OXY USA, Inc.	r
40.	New Mexico State Court	06-28 CV	Malcolm D. Smithson et al. v. Amerada Hess Corporation	r
41.	Montana State Court	CT-1996-1	Williams Companies, Inc. v. State of Montana, Montana Department of Revenue	q
42.	Montana State Court	DV-02-3223	Encana Energy Resources Company v. State of Montana, Department of Revenue	q
43.	Montana State Court	BVD-2004-288	Omimex Canada, Ltd. v. State of Montana, Department of Revenue	q
44.	Montana State Court	BDV-2010-545	Devon Energy Production Company. v. Montana Department of Revenue	q.
45.	Montana State Tax Appeal Board	MT-2011-1	MCR, LLC vs. MT Dept. of Revenue	h,m,u
46.	Texas State Court	B-37,557	James Burr & Ruth Sutton v. Doyle Hartman v. Burlington Northern, Inc.	h, i

47.	Texas State Court	88V-655	Fred K. Fox, et al. v. Mobil Oil Corp. v. Columbia Gas Transmission Corp.	f, h
48.	Texas State Court	93-039414	Pennzoil Gas Marketing Co. v. Enercor, Inc.	j
49.	Probate Court (Texas)	GC-99-01184	Gary Shores, et al. v. Mobil Oil Corp., et al.	a, c, h, p
50.	Arbitration (Dallas)	N/A	Mesa Petroleum Co. v. Kansas Power & Light Co.	b, h
51.	Arbitration (New Orleans)	N/A	Columbia Gas Transmission Corp. v. Adobe Oil & Gas Co., et al.	f, h
52.	Arbitration (Houston)	N/A	Columbia Gas Transmission Corp. v. New Bremen Corp.	f, h
53.	Arbitration (New Orleans)	N/A	Columbia Gas Transmission Corp. v. Cherokee Resources, Inc.	f, h
54.	Arbitration (Santa Fe)	N/A	San Rio Oil & Gas Co. v. El Paso Natural Gas Company	b, h
55.	FPC	CI73-293	Belco Petroleum Corp., et al.	a
56.	FPC	CP74-192	Florida Gas Transmission Corp.	a, f
57.	FPC	RP75-79	Lehigh Portland Cement Co. v. Florida Gas Transmission Corp.	a, l
58.	FPC	RM77-13	Nationwide Rates for New Wellhead Sales of Natural Gas	b, l
59.	FERC	CP78-391	Great Plains Gasification Associates, et al.	a, k

60.	FERC	OR78-1	Trans-Alaska Pipeline System	i, p
61.	FERC	RP74-41	Texas Eastern Transmission Corp.	b, d
62.	FERC	TA81-1-21	Columbia Gas Transmission Corp.	a, f, g
63.	FERC	GP80-11	Columbia Gas Transmission Corp., et al.	b, h
64.	FERC	RP81-109	Texas Eastern Transmission Corp.	b, d, p
65.	FERC	RP81-83	Columbia Gas Transmission Corp.	b, d, p
66.	FERC	RP81-105	Panhandle Eastern Pipe Line Co.	e, i
67.	FERC	RP81-130	Transwestern Pipeline Co.	d, e, i, p
68.	FERC	RP82-57	United Gas Pipe Line Co.	b, c, d, p
69.	FERC	RP82-80	Michigan-Wisconsin Pipeline Co.	b, c, d, p
70.	FERC	CP65-393	Florida Gas Transmission Corp.	l
71.	FERC	RP83-114	Pacific Gas Transmission Corp., et al.	d, e, i, p
72.	FERC	RP83-93	Trunkline Gas Company	f, g
73.	FERC	TA82-1-21	Columbia Gas Transmission Corp.	a, f, g
74.	FERC	RP85-122	Colorado Interstate Gas Co.	b, c, f
75.	FERC	TA85-1-16	National Fuel Gas Supply Corporation	f, g
76.	FERC	RP81-85	Trunkline LNG Co., et al.	a, f, g
77.	FERC	RP85-203	Panhandle Eastern Pipe	a, f, g

			Line Company	
78.	FERC	RM86-3	Ceiling Prices-Old Gas Pricing Structure	b, k
79.	FERC	TA86-1-29	Transcontinental Gas Pipe Line Corporation	e, f, g
80.	FERC	RP87-15	Trunkline Gas Co.	e, f, g
81.	FERC	RP87-103	Panhandle Eastern Pipe Line Company	b, c, e
82.	FERC	CP82-487	Williston Basin Interstate Pipeline Company	g
83.	FERC	RP86-119	Tennessee Gas Pipeline Co.	e, f, g
84.	FERC	RP86-51	Northwest Pipeline Corp.	a, e, f
85.	FERC	RP87-7	Transcontinental Gas Pipeline Corp.	a, f
86.	FERC	TA87-4-49	Williston Basin Interstate Pipeline Company	d, g
87.	FERC	TA87-4-21	Columbia Gas Transmission Corp.	a, f, g
88.	FERC	GP84-56-007	Williams Natural Gas, et al. Company	a, f, g
89.	FERC	RP90-2	Williston Basin Interstate Pipeline Co.	d
90.	FERC	RP90-104	Texas Gas Transmission, et al. Corp.	d, e, p
91.	FERC	RP90-119	Texas Eastern Transmission Corp.	b, d, p
92.	FERC	91-203, et al.	Tennessee Gas Pipeline Company	b, e, p
93.	FERC	RP94-68-000	Mississippi River Transmission Corp.	b, e, p
94.	FERC	RP94-96, et al.	CNG Transmission Corp.	b, d, p

95.	FERC	RP95-112	Tennessee Gas Pipeline Company	b, d, p
96.	FERC	RP95-364-005	Williston Basin Interstate Pipeline Company	n
97.	Surface Transportation Board	41191	AEP Texas North Co. v. Burlington Northern and Santa Fe Railroad Company	s, t
98.	Surface Transportation Board	42088	Western Fuels Association, Inc., et.al. v. BNSF Railway Company	s, t
99.	Surface Transportation Board	42081	Dyno Nobel, Inc. v. Kaneb Pipe Line Partners, L.P.	s, t
100.	MI PSC	U-5955(I)	Michigan Consolidated Gas Co.	b, c
101.	MI PSC	U-5995(P)	Michigan Consolidated Gas Company	b, c
102.	MI PSC	U-6133	Michigan Consolidated Gas Company	g
103.	MI PSC	U-7298	Michigan Consolidated Gas Company	b, c
104.	MN PSC	GR85-108	Northern States Power Co.	d
105.	OH PUC	79-125	Columbia Gas of Ohio, Inc.	a, l
106.	OH PUC	79-535	East Ohio Gas Co.	b, c, d
107.	OH PUC	80-769	East Ohio Gas Co.	b, c, d
108.	OH PUC	81-1024	Colombia Gas of Ohio, Inc.	d
109.	OH PUC	81-1025	Columbia Gas of Ohio, Inc.	d
110.	OH PUC	84-6	Columbia Gas of Ohio,	f, g

			Inc.	
111.	OH PUC	85-21	Columbia Gas of Ohio, Inc.	f, g
112.	RI PUC	1398	Providence Gas Co.	c, d
113.	PA PUC	R-7909056	National Fuel Gas Distribution Corp.	a, b
114.	PA PUC	R-81160	National Fuel Gas Distribution Corp.	d
115.	PA PUC	R-822133	Equitable Gas Co.	d
116.	PA PUC	R-832469	National Fuel Gas Distribution Corp.	f, g
117.	PA PUC	R-850032	Philadelphia Electric Co.	f, g
118.	PA PUC	R-850041	National Fuel Gas Distribution Corp.	f, g
119.	PA PUC	R-860314	Columbia Gas of Pennsylvania, Inc.	f, g
120.	PA PUC	R-850270	Peoples Natural Gas Co.	b, d
121.	PA PUC	R-860310	Peoples Natural Gas Co.	f, g
122.	PA PUC	R-922324	Pennsylvania Gas & Water Company	b, g, h
123.	PA PUC	R-932676	Pennsylvania Gas & Water Company	a, g
124.	PA PUC	R-942993	Pennsylvania Gas & Water Company	b, e
125.	PA PUC	R-00963612	PG Energy, Inc.	b, d, e
126.	DC PSC	772(PI)	Washington Gas Light Co.	a, b, c
127.	DC PSC	772 (PII)	Washington Gas Light Co.	a, b, c
128.	DC PSC	787	Washington Gas Light Co.	d

129.	DC PSC	F.C. 989	Washington Gas Light Co.	a, d
130.	NV PSC	82-239	Rulemaking on Natural Gas Rate Design	d
131.	NV PSC	93-3003	Southwest Gas Corporation Northern Nevada Division	d, g
132.	NV PSC	93-3004	Southwest Gas Corporation Southern Nevada Division	d, g
133.	OK CC	28331	Public Service Company of Oklahoma	b, c
134.	NM PSC	1982	Public Service Company of New Mexico	f, g
135.	SC PSC	87-530-G	South Carolina Pipeline Corp.	f, g
136.	SC PSC	87-227-G	South Carolina Electric & Gas Company	f, g
137.	SC PSC	87-427-G	Peoples Natural Gas Co.	f, g
138.	TX PUC	5820	Gulf States Utilities Co.	g
139.	TX PUC	16705	Entergy Gulf States, Inc.	f, h, j
140.	WV PSC	87-770-G-C	Cameron Gas Co. v. Hope Gas, Inc.	d, e
141.	WV PSC	05-0304-G-42T	Hope Gas, Inc.	d
142.	WV PSC	04-1595-G-42T	Mountaineer Gas Company	b, d
143.	WV PSC	05-1278-E-PC-PW-42-T	Appalachian Power Co. and Wheeling Power Company	d
144.	WV PSC	08-1281-6-30C	Equitable Gas Company	g, m
145.	WV PSC	11-1103-G-30C	Hope Gas, Inc.	b, g, m, v
146.	MT PSC	90.1.1	Montana Power Co.	a, b, k, o

147.	MT PSC	90.3.20	Great Falls Gas Company	b, d
148.	MT PSC	91.5.18, et al.	Montana-Dakota Utilities Company	b, f, g
149.	MT PSC	91.11.63	Montana-Dakota Utilities Company	b, e
150.	MT PSC	93.4.19, et al.	Montana-Dakota Utilities Company	d, e, h
151.	MT PSC	D95.7.90	Montana-Dakota Utilities Company	b, d, e
152.	MT PSC	D96.2.22	Montana Power Co.	b, d, e, k
153.	MT PSC	D98.3.68	Energy West Montana	d, f, g
154.	MT PSC	D98.9.213	Energy West Montana	f, g
155.	MT PSC	D99.8.176	Montana Power Company	d, e
156.	MT PSC	D96.2.22	Montana Power Co.	o
157.	MT PSC	D99.8.176	Montana Power Co.	d, e
158.	MT PSC	D99.10.243	Energy West Montana	a, f, g
159.	MT PSC	D96.2.22	Montana Power Co.	m, o
160.	MT PSC	D2001.12.156	Montana Power Co.	a, f, g, v
161.	MT PSC	D2002.5.59	Montana Dakota Utilities Company	d, e
162.	MT PSC	D2002.11.140	NorthWestern Energy	a, f, g
163.	MT PSC	D2003.6.75	Energy West Montana	f, g, h
164.	MT PSC	D2004.4.50	Montana Dakota Utilities Company	d, e
165.	MT PSC	D2004.3.46	Energy West Montana	d, e
166.	MT PSC	D2006.5.58	NorthWestern Energy	f, v
167.	MT PSC	D2004.7.120 and D2006.6.80	Energy West Montana	f v
168.	MT PSC	N2005.6.101	NorthWestern Energy	f, v
169.	MT PSC	D2005.5.87	NorthWestern Energy	f, v

170.	MT PSC	D2003.4.49 et al.	Montana-Dakota Utilities Co.	f, v
171.	MT PSC	D2007.5.44	NorthWestern Energy	f, g, v
172.	MT PSC	D2008.3.27	Cut Bank Gas Company	m, o
173.	MT PSC	D2007.7.82	NorthWestern Energy	d, b
174.	MT PSC	N2008.12.138	NorthWestern Energy	a, f, h, v
175.	MT PSC	D2009.9.129	NorthWestern Energy	d, f, h, k, v
176.	MT PSC	D2010.5.55	CenturyLink/Qwest	b, i
177.	MT PSC	D2010.9.90	Energy West Montana	d, m
178.	MT PSC	D2011.5.36	NorthWestern Energy	f, g, v
179.	MT PSC	D2011.6.45	NorthWestern Energy	b, g, v
180.	MT PSC	D2012.3.25	NorthWestern Energy	m, o
181.	MT PSC	D2012.1.3	NorthWestern Energy	b, m
182.	MT PSC	D2012.9.94	NorthWestern Energy	b,d
183.	AZ CC	U-1551-92-253	Southwest Gas Corporation Central Arizona Division	d, g
184.	CN DPUC	93-02-04	Connecticut Natural Gas Corporation	b, d, e
185.	MDPSC	9180	Washington Gas Light Company	a, h
186.	DOE/ERA	None	In the Matter of No. 2 (Home Heating) Oil	i
187.	Congress	None	Senate Subcommittee on Antitrust and Monopoly	a
188.	Congress	None	Senate Joint Subcommittee on Antitrust and Monopoly and Government Operations	a, j
189.	Congress	None	House Committee on	a, j

			Small Business	
190.	Congress	None	House Ad Hoc Committee on Outer Continental Shelf	a, j
191.	Congress	None	House Committee on Interstate and Foreign Commerce	a
192.	Congress	None	House Subcommittee on Mines and Mining	a

N/A = Not Available

Issue Codes	Description
a	Gas Supply
b	Utility Rate Levels
c	Utility Sales/Transportation Volumes
d	Utility Rate Design/Cost of Service
e	Utility Tariff Matters
f	Gas Acquisition Practices
g	Purchased Gas Adjustments
h	Gas Supply Contract Matters
i	Competition/Antitrust
j	Oil/Gas Leasing Policy
k	Gas Production Costs
l	Gas Curtailment
m	Natural Gas Markets
n	Cost of Capital
o	Market Value Analysis
p	Pipeline Rates
q	Property Tax Appraisals
r	Royalty Valuation
s	Rail Transportation Rates
t	Petroleum Product Markets
u	Natural Gas Production Tax
v	Energy Price Risk / Hedging Strategies

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Operating Income and Rate of Return	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Sales Revenues	73,742,148	44,762,102	8,329,512	17,935,809	1,971,742	742,983
Adjustments to Sales Revenues	(14,819,134)	(9,032,186)	(1,681,398)	(3,327,140)	(584,231)	(194,179)
Total Sales Revenues	58,923,014	35,729,916	6,648,114	14,608,669	1,387,511	548,804
Other Revenues	368,827	215,899	32,152	68,952	11,852	39,972
Adjustments to Other Revenues	47,287	25,523	4,055	9,462	1,825	6,422
Total Other Revenues	416,114	241,422	36,207	78,414	13,677	46,394
Total Operating Revenues	59,339,128	35,971,338	6,684,321	14,687,083	1,401,188	595,198
Operating Expense						
Cost of Gas	52,735,031	31,910,290	6,052,454	13,503,155	1,177,123	92,009
Adj. to Cost of Gas	(13,880,459)	(8,393,793)	(1,735,946)	(3,110,617)	(548,094)	(92,009)
Total Cost of Gas	38,854,572	23,516,497	4,316,508	10,392,538	629,029	0
Other O&M Expense	10,869,308	6,190,848	866,487	1,765,648	405,051	1,641,274
Adjustments to Other O&M	247,766	152,464	20,334	43,910	7,258	23,800
Total Other O&M Expense	11,117,074	6,343,312	886,821	1,809,558	412,309	1,665,074
Total Operation & Maintenance Expense	49,971,646	29,859,809	5,203,329	12,202,096	1,041,338	1,665,074
Depreciation Expense	3,011,293	1,716,940	267,174	623,106	99,088	304,985
Adjustment to Depreciation Expense	1,412,308	878,353	120,226	225,374	41,855	146,500
Total Depreciation Expense	4,423,601	2,595,293	387,400	848,480	140,943	451,485
Taxes Other Than Income Taxes	3,308,019	1,824,420	292,037	665,944	121,147	404,471
Adjustment to Taxes Other Than Income	(32,520)	(27,877)	(7,392)	(15,194)	1,193	16,750
Total Taxes Other Than Income	3,275,499	1,796,543	284,645	650,750	122,340	421,221
Current Income Taxes - Fed. & State	(2,930,186)	(1,206,876)	(41,730)	(357,359)	(85,479)	(1,238,742)
Adjustment to Current Income Taxes	(362,890)	(277,627)	28,897	(42,349)	(14,419)	(57,392)
Total Current Income Taxes	(3,293,076)	(1,484,503)	(12,833)	(399,708)	(99,898)	(1,296,134)

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Operating Income and Rate of Return	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Deferred Income Taxes	3,489,203	1,943,776	308,899	718,772	121,101	396,655
Adjustment to Deferred Income Tax	(154,778)	(94,340)	(16,196)	(41,373)	(2,495)	(374)
Total Deferred Income Taxes	3,334,425	1,849,436	292,703	677,399	118,606	396,281
Total Operating Expenses	57,712,095	34,616,578	6,155,244	13,979,017	1,323,329	1,637,927
Pro Forma Operating Income	1,627,033	1,354,760	529,077	708,066	77,859	(1,042,729)
Rate Base	43,247,498	24,485,956	4,079,220	9,390,031	1,234,409	4,057,882
Adjustment to Rate Base	512,332	1,039,437	3,750	(379,080)	(48,621)	(103,154)
Total Pro Forma Rate Base	43,759,830	25,525,393	4,082,970	9,010,951	1,185,788	3,954,728
Pro Forma Rate of Return	3.718%	5.307%	12.958%	7.858%	6.566%	-26.367%

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Rate Base							
Gas Plant in Service							
Production Plant	3	3,034,769	1,826,714	335,298	807,272	65,485	0
Distribution Plant					0		
Land	13	15,962	6,496	1,194	2,870	959	4,443
Rights of Way	13	22,846	9,300	1,708	4,108	1,372	6,359
Structures & Improvements	13	168,491	68,577	12,601	30,294	10,119	46,898
Direct to Small IT	Direct	24,611	0	0	0	24,611	0
Direct to Large IT	Direct	2,062	0	0	0	0	2,062
					0		
Mains - $28,623,324							
Demand 50% - Energy 50%	45	28,623,324	11,649,973	2,140,684	5,146,482	1,719,125	7,967,060
Meas. & Reg. Equip. - General	13	576,181	234,511	43,091	103,597	34,606	160,376
Meas. & Reg. Equip. - City Gate	13	22,301	9,077	1,668	4,010	1,339	6,207
Direct to Firm General	Direct	3,913	0	3,913	0	0	0
Direct to Small IT	Direct	83,476	0	0	0	83,476	0
Direct to Large IT	Direct	18,532	0	0	0	0	18,532
Services	46	20,458,685	13,138,385	1,916,611	4,426,184	401,855	575,649
Meters	46	18,117,820	11,635,101	1,697,314	3,919,744	355,876	509,784
Service Regulators	46	1,979,814	1,271,418	185,473	428,328	38,888	55,706
Direct to Firm General	Direct	27,085	0	27,085	0	0	0
Direct to Small IT	Direct	12,521	0	0	0	12,521	0
Ind. Meas. & Reg. Station Equipment	13	146,005	59,425	10,919	26,252	8,769	40,640
Direct to Small IT	Direct	8,161	0	0	0	8,161	0
Direct to Large IT	Direct	33,659	0	0	0	0	33,659
Property on Customer Premise	13	148,674	60,512	11,119	26,732	8,930	41,382
Cathodic Protection & Other Equipment	13	1,183,575	481,727	88,517	212,807	71,086	329,438
Distribution Plant		71,677,698	38,624,502	6,141,897	14,331,408	2,781,693	9,798,195
General Plant	15	5,982,213	3,223,598	512,603	1,196,097	232,160	817,757
Intangible Plant - General	15	55,760	30,046	4,778	11,149	2,164	7,623
Common Plant	15	10,595,932	5,709,764	907,941	2,118,575	411,212	1,448,443
Intangible Plant - Common	15	2,759,471	1,486,980	236,453	551,735	107,090	377,214

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Total Gas Plant in Service		94,105,843	50,901,604	8,138,970	19,016,236	3,599,804	12,449,232
Less: Accumulated Depreciation							
Production Plant	3	50,797	30,577	5,612	13,512	1,096	0
Distribution Plant							
Rights of Way	13	14,219	5,787	1,063	2,556	854	3,958
Structures & Improvements	17	164,245	50,008	9,189	44,018	25,326	35,703
Mains	13	19,340,970	7,871,964	1,446,475	3,477,512	1,161,624	5,383,395
Meas. & Reg. Equip. - General	18	457,800	186,329	34,238	82,312	27,496	127,425
Meas. & Reg. Equip. - City Gate	19	126,357	8,945	5,500	3,952	83,582	24,379
Services	46	15,458,953	9,927,601	1,448,226	3,344,505	303,650	434,971
Meters	46	5,457,201	3,504,566	511,242	1,180,651	107,192	153,551
Service Regulators	20	887,096	558,512	93,373	188,157	22,583	24,471
Ind. Meas. & Reg. Station Equipment	21	67,888	21,479	3,947	9,489	6,120	26,855
Property on Customer Premise	13	143,163	58,270	10,706	25,740	8,598	39,849
Cathodic Protection & Other Equipment	13	775,459	315,620	57,995	139,428	46,574	215,842
Distribution Plant		42,893,351	22,509,081	3,621,954	8,498,320	1,793,599	6,470,399
General Plant	15	3,177,682	1,712,337	272,289	635,353	123,320	434,384
Intangible Plant - General	15	55,760	30,046	4,778	11,149	2,164	7,623
Common Plant	15	2,977,057	1,604,228	255,097	595,240	115,535	406,959
Intangible Plant - Common	15	2,104,538	1,134,059	180,333	420,787	81,674	287,686
Gas Plant Leased to Others	15	0	0	0	0	0	0
Less: Total Accumulated Reserve for Depreciation		51,259,185	27,020,328	4,340,063	10,174,361	2,117,388	7,607,051
Net Gas Plant in Service		42,846,658	23,881,276	3,798,907	8,841,875	1,482,416	4,842,181
CWIP in Service	15	500,474	269,688	42,885	100,066	19,423	68,413
Total Gas Plant in Service		43,347,132	24,150,964	3,841,792	8,941,941	1,501,839	4,910,594
Additions							
Materials & Supplies	15	533,337	287,395	45,700	106,636	20,698	72,907
Prepaid Insurance	24	25,908	14,439	2,297	5,346	897	2,927
Gas in Underground Storage	33	7,134,766	4,318,274	792,630	1,908,355	115,507	0
Prepaid Demand/Commodity	33	1,149,982	696,021	127,756	307,588	18,617	0
Other	24	128,892	71,840	11,428	26,598	4,459	14,567
Unamortized Loss on Debt	24	584,820	325,960	51,852	120,684	20,233	66,092
Total Additions		9,557,705	5,713,929	1,031,663	2,475,207	180,411	156,493

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Total Before Deductions		52,904,837	29,864,893	4,873,455	11,417,148	1,682,250	5,067,087
Deductions							
Accumulated Deferred Income Tax	24	(8,925,996)	(4,975,048)	(791,404)	(1,841,977)	(308,823)	(1,008,743)
Accumulated Investment Tax Credit	24	(4,084)	(2,276)	(362)	(843)	(141)	(462)
Customer Advances For Construction	Direct	(727,256)	(401,613)	(2,469)	(184,297)	(138,877)	0
Total Deductions		(9,657,336)	(5,378,937)	(794,235)	(2,027,117)	(447,841)	(1,009,205)
Total Rate Base		43,247,501	24,485,956	4,079,220	9,390,031	1,234,409	4,057,882
Gas Operating Revenues							
Retail Sales & Transportation							
Residential	Direct	45,522,909	45,522,909	0	0	0	0
Firm General	Direct	26,717,947	0	8,471,072	18,246,875	0	0
Small Interruptible	Direct	2,001,287	0	0	0	2,001,287	0
Large Interruptible	Direct	754,669	0	0	0	0	754,669
Total Sales & Transportation Revenues		74,996,812	45,522,909	8,471,072	18,246,875	2,001,287	754,669
Other Operating Revenue							
Miscellaneous							
Reconnect Fees	11	1,480	1,317	123	40	0	0
NSF Check Fees	11	28,024	24,932	2,327	765	0	0
Miscellaneous	24	15,830	8,823	1,404	3,266	547	1,790
Rent From Gas Property	24	244,710	136,394	21,696	50,499	8,466	27,656
Other Gas Revenues					0		
Miscellaneous	31	42,705	24,324	3,404	6,937	1,591	6,449
Transport and Penalty Revenue - Net	24	36,077	20,109	3,198	7,445	1,248	4,077
Total Other Operating Revenue		368,826	215,899	32,152	68,952	11,852	39,972
Unbilled Revenue	26	(1,254,664)	(760,807)	(141,560)	(311,066)	(29,545)	(11,686)
Total Operating Revenues		74,110,974	44,978,001	8,361,664	18,004,761	1,983,594	782,955
Operation & Maintenance Expenses							
Cost of Purchased Gas	Direct	52,735,031	31,910,290	6,052,454	13,503,155	1,177,123	92,009
Production Expense	3	188,558	113,498	20,833	50,158	4,069	0
Other Gas Supply Expenses	3	73,609	44,307	8,133	19,581	1,588	0

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Total Production Expense		262,167	157,805	28,966	69,739	5,657	0
Distribution Expenses							
Operation							
Load Dispatch	1	74,482	30,249	5,552	13,367	4,489	20,825
Mains and Services	22	1,138,365	574,919	94,102	222,020	49,192	198,132
Measuring Stations - General	18	34,815	14,170	2,604	6,260	2,091	9,690
Measuring Stations - Industrial	21	14,521	4,594	844	2,029	1,308	5,744
Measuring Stations - City Gate	19	0	0	0	0	0	0
Meters & House Regulators	16	267,551	171,479	25,375	57,770	5,411	7,513
Customer Installations	10	538,992	382,588	39,273	106,841	8,801	1,489
Other Gas Distribution	27	832,223	473,896	67,484	164,250	28,680	97,914
Rents	27	33,379	19,007	2,707	6,588	1,150	3,928
Supervision & Engineering	27	514,850	293,172	41,748	101,611	17,743	60,574
Total Operation Expense		3,449,178	1,964,074	279,689	680,736	118,865	405,809
Maintenance							
Structures & Improvements	17	1,179	359	66	316	182	256
Mains	13	138,093	56,205	10,328	24,830	8,294	38,437
Measuring Stations - General	18	28,158	11,461	2,106	5,063	1,691	7,837
Measuring Stations - Industrial	21	15,721	4,974	914	2,197	1,417	6,219
Measuring Stations - City Gate	19	0	0	0	0	0	0
Services	10	155,111	110,101	11,302	30,747	2,533	428
Meters & House Regulators	16	284,028	182,042	26,939	61,328	5,744	7,976
Other Equipment	28	120,738	70,845	10,022	24,152	3,853	11,865
Supervision & Engineering	28	130,671	76,676	10,847	26,139	4,171	12,841
Total Maintenance Expense		873,699	512,663	72,524	174,772	27,885	85,859
Total Distribution Expenses		4,322,877	2,476,737	352,213	855,508	146,750	491,668
Customer Accounts	8	96,853	86,114	8,036	2,643	54	6
Meter Reading	10	230,640	163,714	16,805	45,718	3,766	637
Customer Records & Collection	8	1,376,127	1,223,552	114,174	37,547	767	87
Uncollectible Accounts	11	173,361	154,236	14,392	4,733	0	0
Miscellaneous Customer Accounts	8	71,102	63,218	5,899	1,940	40	5
Customer Service & Information	8	89,100	79,221	7,392	2,431	50	6
Sales Expenses	8	119,573	106,315	9,921	3,262	67	8

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Administration & General Expenses	45	4,127,510	1,679,936	308,689	742,127	247,900	1,148,857
Total Gas O&M Expenses		63,604,341	38,101,138	6,918,941	15,268,803	1,582,174	1,733,283
O&M Excl. Cost of Gas and A&G		6,741,800	4,510,912	557,798	1,023,521	157,151	492,417
O&M Excl. Cost of Gas		10,869,310	6,190,848	866,487	1,765,648	405,051	1,641,274
Depreciation Expense							
Production Plant	3	101,594	61,152	11,225	27,025	2,192	0
Distribution Plant							
Rights of Way	13	317	130	23	57	19	88
Structures & Improvements	17	3,533	1,075	198	947	544	768
Mains	13	590,840	240,478	44,188	106,233	35,486	164,455
Meas. & Reg. Equip. - General	18	18,947	7,712	1,417	3,406	1,138	5,274
Meas. & Reg. Equip. - City Gate	19	3,603	255	156	113	2,384	695
Services	46	1,160,453	745,232	108,713	251,061	22,794	32,652
Meters	46	519,807	333,814	48,697	112,459	10,210	14,626
Service Regulators	20	30,901	19,455	3,253	6,554	787	853
Ind. Meas. & Reg. Station Equipment	21	4,563	1,443	265	638	412	1,805
Property on Customer Premise	13	0	0	0	0	0	0
Cathodic Protection & Other Equipment	13	34,801	14,164	2,602	6,257	2,091	9,686
Total Distribution Plant		2,469,359	1,424,910	220,737	514,750	78,057	230,902
General Plant	15	115,122	62,035	9,864	23,018	4,467	15,737
Amort. of Intangible Plant - General	15	0	0	0	0	0	0
Common Plant	15	315,830	170,188	27,063	63,148	12,257	43,174
Amort. of Intangible Plant - Common	15	110,987	59,807	9,510	22,190	4,307	15,172
Total Depreciation Expense		3,011,298	1,716,940	267,174	623,106	99,088	304,985
Taxes Other Than Income							
Ad Valorem Taxes-Production	3	64,378	38,751	7,113	17,125	1,389	0
Ad Valorem Taxes-Other	15	2,439,698	1,314,664	209,052	487,799	94,680	333,502
Other Taxes - Payroll, Franchise, Other	31	448,033	255,188	35,716	72,780	16,696	67,654
Other Taxes - Revenue	26	355,910	215,817	40,156	88,240	8,382	3,315
Total Taxes Other Than Income Taxes		3,308,019	1,824,420	292,037	665,944	121,147	404,471
Total Operating Expense		69,923,658	41,642,498	7,478,152	16,557,853	1,802,409	2,442,739
Interest Expense	24	1,269,714	707,697	112,577	262,020	43,930	143,493

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Taxable Income Before Adjustments		2,917,602	2,627,806	770,935	1,184,888	137,255	(1,803,277)
Deductions							
Unrecovered Purchased Gas Cost	33	52,394	31,711	5,821	14,014	848	0
Other Income Tax Charges	24	6,128,908	3,416,048	543,406	1,264,767	212,049	692,639
Preferred Dividend Paid Deduction	24	13,836	7,712	1,227	2,855	479	1,564
Total Deductions		6,195,138	3,455,471	550,454	1,281,636	213,376	694,203
Taxable Income (Before State Income Tax)		(3,277,536)	(827,665)	220,481	(96,748)	(76,121)	(2,497,480)
Less: State Income Tax	35	(386,615)	(97,630)	26,007	(11,413)	(8,979)	(294,601)
Federal Taxable Income		(2,890,921)	(730,035)	194,474	(85,335)	(67,142)	(2,202,879)
Federal Income Tax							
@ Current Rate of 35%		(1,011,822)	(255,512)	68,066	(29,868)	(23,500)	(771,008)
State Income Taxes	35	(386,615)	(97,630)	26,007	(11,413)	(8,979)	(294,601)
Credits and Adjustments	40	29,134	16,248	2,589	6,027	1,004	3,265
Rounding & Prior Year's Adjustments - Federal	24	(1,236,864)	(689,386)	(109,663)	(255,240)	(42,793)	(139,780)
Federal and State Income Taxes		(2,606,167)	(1,026,280)	(13,001)	(290,494)	(74,268)	(1,202,124)
Rounding & Prior Year's Adjustment - State	24	(324,018)	(180,596)	(28,729)	(66,865)	(11,211)	(36,618)
Federal & State Income Taxes		(2,930,185)	(1,206,876)	(41,730)	(357,359)	(85,479)	(1,238,742)
Deferred Income Taxes							
Unrecovered Purchased Gas Cost	33	(20,643)	(12,493)	(2,294)	(5,522)	(334)	0
Other Deferred Income Tax Chgs	24	2,206,874	1,230,038	195,669	455,413	76,354	249,403
Closing/Filing & Out of Period	24	1,302,970	726,231	115,524	268,881	45,081	147,252
Total Deferred Income Taxes		3,489,201	1,943,776	308,899	718,772	121,101	396,655
Total Operating Expenses		70,482,674	42,379,398	7,745,321	16,919,266	1,838,031	1,600,652
Total Operating Income		3,628,300	2,598,603	616,343	1,085,495	145,563	(817,697)

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Summary of Pro Forma Rate Base Adjustments							
Plant							
Plant Additions - Adj. A							
Production	3	74,440	44,807	8,225	19,802	1,606	0
Distribution							
Mains-Demand Related	45	957,339	389,647	71,597	172,129	57,498	266,468
Meas. & Reg. Equip. General	13	14,164	5,765	1,059	2,547	851	3,943
Services	46	1,324,687	850,701	124,099	286,593	26,020	37,273
Positive Meters	46	573,629	368,380	53,738	124,103	11,267	16,140
Service Regulators	46	131,754	84,612	12,343	28,504	2,588	3,707
Cathodic Protection Equip	13	109,023	44,373	8,154	19,602	6,547	30,345
Other Distribution Equipment	13	(118)	(48)	(9)	(21)	(7)	(33)
Total Distribution Plant Additions		3,110,478	1,743,430	270,981	633,457	104,764	357,843
General	15	309,554	166,806	26,526	61,893	12,014	42,315
Common	15	394,348	212,501	33,791	78,847	15,303	53,907
Common Intangible	8	2,468,802	2,195,079	204,831	67,359	1,377	156
Total Plant Additions - Adj. A		6,357,622	4,362,623	544,354	861,358	135,064	454,221
Accumulated Reserve for Depreciation							
Plant Additions - Adj. B							
Production	3	102,565	61,737	11,332	27,283	2,213	0
Distribution	23	2,607,909	1,407,655	223,620	521,834	100,652	354,147
General	15	(33,342)	(17,966)	(2,858)	(6,667)	(1,294)	(4,558)
Common	15	360,927	194,491	30,928	72,164	14,007	49,338
Common Intangible	8	164,587	146,339	13,655	4,491	92	10
Total Accumulated Reserve - Adj. B		3,202,646	1,792,256	276,677	619,105	115,670	398,937
					0		
Net Adjustment to Plant		3,154,976	2,570,367	267,677	242,253	19,394	55,284
Additions					0		
Materials and Supplies - Adj. C	15	99,695	53,721	8,542	19,933	3,869	13,628
Gas in Underground Storage - Adj. D	33	(855,502)	(517,788)	(95,041)	(228,823)	(13,850)	0
Prepaid Demand and Commodity-Adj. E	33	93,808	52,286	8,317	19,358	3,246	10,601
Prepaid Insurance - Adj. F	24	(642,915)	(389,119)	(71,424)	(171,963)	(10,409)	0
Unamortized Loss on Debt - Adj. G	24	(53,806)	(29,989)	(4,770)	(11,103)	(1,862)	(6,081)
Provision for Pensions & Benefits - Adj. H	24	1,268,837	707,206	112,499	261,838	43,899	143,394
Provision for Injuries & Damages - Adj. I	24	(109,736)	(61,163)	(9,729)	(22,646)	(3,797)	(12,401)

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Deferred FAS 106 Costs - Adj. J	24	273,775	152,591	24,274	56,497	9,472	30,940
Total		74,156	(32,255)	(27,332)	(76,909)	30,568	180,081
Deductions							
Accumulated Def. Inc. Tax							
Plant Additions - Adj. K	41	1,887,637	1,038,374	163,153	373,485	70,175	242,447
Normalization - Adj L	24	(25,349)	(14,129)	(2,247)	(5,230)	(877)	(2,865)
Def. FAS 106 - Adj. J	24	105,855	59,001	9,385	21,844	3,663	11,964
Unamortized Loss on Debt - Adj. G	24	(31,526)	(17,572)	(2,795)	(6,505)	(1,091)	(3,562)
Pension - Adj. H	24	846,179	471,630	75,025	174,618	29,276	95,628
Injuries and Damages - Adj. I	24	(41,583)	(23,179)	(3,686)	(8,582)	(1,439)	(4,699)
Investment Tax Credits - Adj. M	24	(3,488)	(1,944)	(309)	(720)	(121)	(394)
Customer Advances for Construction - Adj. N	Direct	(20,926)	(13,506)	(1,931)	(4,486)	(1,003)	0
Total		2,716,799	1,498,675	236,595	544,424	98,583	338,519
Total Pro Forma Adjustments - Rate Base		512,333	1,039,437	3,750	(379,080)	(48,621)	(103,154)
Pro Forma Adjustments - Operating Income							
Pro Forma Revenue Adjustments							
Revenue Adjustments - Adj. No. 1-3 to Proforma							
Residential	Direct	(9,792,993)	(9,792,993)	0	0	0	0
Firm General	Direct	(5,461,164)	0	(1,822,958)	(3,638,206)	0	0
Small Interruptible	Direct	(613,776)	0	0	0	(613,776)	0
Large Interruptible	Direct	(205,865)	0	0	0	0	(205,865)
Total Retail Sales Adjustment		(16,073,798)	(9,792,993)	(1,822,958)	(3,638,206)	(613,776)	(205,865)
Unbilled Revenue	26	1,254,664	760,807	141,560	311,066	29,545	11,686
Total		(14,819,134)	(9,032,186)	(1,681,398)	(3,327,140)	(584,231)	(194,179)
Other Revenue - Adj. No. 4	23	47,286	25,523	4,055	9,462	1,825	6,422
Total Pro Forma Revenue Adjustments		(14,771,848)	(9,006,663)	(1,677,343)	(3,317,678)	(582,406)	(187,757)
OPERATION & MAINTENANCE EXPENSES							
Cost of Gas - Adj. No. 5	Direct	(13,880,459)	(8,393,793)	(1,735,946)	(3,110,617)	(548,094)	(92,009)
Labor Expense - Adj. No. 6							
Other Gas Supply	30	2,495	1,669	207	379	58	182

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Production	3	1,334	803	147	355	29	0
Distribution	29	160,710	92,077	13,094	31,805	5,455	18,279
Customer Accounting	8	50,020	44,474	4,150	1,365	28	3
Customer Service	8	2,645	2,353	219	72	1	0
Sales	8	4,111	3,656	341	112	2	0
A&G	30	48,407	32,391	4,005	7,349	1,128	3,536
Total -Labor Expense - Adj. No. 6		269,722	177,423	22,163	41,437	6,701	22,000
Benefits Expense - Adj. No. 7	30	(75,501)	(50,519)	(6,247)	(11,463)	(1,760)	(5,514)
Vehicles and Work Equip. - Adj. No. 8	30	(6,716)	(4,494)	(556)	(1,019)	(157)	(490)
Company Consumption - Adj. No. 9	30	(8,120)	(5,434)	(672)	(1,232)	(189)	(594)
Uncollectible Accounts - Adj. No. 10	11	(14,963)	(13,312)	(1,242)	(409)	0	0
Advertising - Adj. No. 11	8	(31,656)	(28,146)	(2,626)	(864)	(18)	(2)
Insurance Expense - Adj. No. 12	30	13,839	9,261	1,145	2,102	323	1,011
Industry Dues - Adj. No. 13	30	(7,138)	(4,778)	(591)	(1,084)	(166)	(521)
Regulatory Commission Expense - Adj. No. 14	30	108,300	72,463	8,960	16,442	2,524	7,910
Total		53,546	25,560	4,418	13,936	2,317	7,314
Total Adjustments to O&M		(13,632,692)	(8,241,329)	(1,715,612)	(3,066,707)	(540,836)	(68,209)
DEPRECIATION EXPENSE							
Average Annual Depreciation - Adj. No. 15							
Production Plant	3	1,943	1,169	215	517	42	0
Distribution Plant	23	1,082,553	584,322	92,827	216,616	41,781	147,008
General Plant	41	(4,128)	(2,271)	(356)	(816)	(153)	(529)
Common	8	331,936	295,133	27,540	9,057	185	21
Total Average Annual Depreciation Adj. 15		1,412,304	878,353	120,226	225,374	41,855	146,500
TAXES OTHER THAN INCOME							
Ad Valorem Taxes - Adj. No. 16							
Production Plant	3	1,578	950	174	420	34	0
Distribution Plant	23	101,664	54,875	8,717	20,343	3,924	13,806
General Plant	41	5,288	2,906	458	1,045	197	679
Common Plant	41	5,857	3,223	507	1,158	218	753
Total Ad Valorem Taxes		114,387	61,954	9,856	22,966	4,373	15,238
Payroll Taxes - Adj. No. 17	31	20,322	11,574	1,620	3,301	758	3,069
Montana Consumer Counsel & PSC Tax - Adj. 18	26	(167,229)	(101,405)	(18,868)	(41,461)	(3,938)	(1,557)

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	Allocation Factor	Total Montana	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Total Adjustments to Taxes Other than Income		(32,520)	(27,877)	(7,392)	(15,194)	1,193	16,750
CURRENT INCOME TAXES					0		
Interest Annualization - Adj. No. 19	24	(51,878)	(28,916)	(4,599)	(10,705)	(1,795)	(5,863)
Tax Depreciation on Plant Additions - Adj. No. 20	41	2,817,177	1,549,708	243,496	557,404	104,732	361,836
Other Tax Deductions - Adj. No. 21	24	(400,022)	(222,958)	(35,468)	(82,549)	(13,839)	(45,207)
		2,365,277	1,297,834	203,429	464,150	89,098	310,766
					0		
Net Adjustments to Operating Income		(4,884,217)	(2,913,644)	(277,994)	(925,301)	(173,716)	(593,564)
					0		
Income Taxes on Pro Forma Adj. - Adj. No. 22	(Calculated)	(1,923,771)	(1,147,612)	(109,495)	(364,453)	(68,422)	(233,790)
0.393875					0		
Elimination of Closing/Filing&Res. - Adj. No. 23	24	1,560,882	869,985	138,392	322,104	54,003	176,398
Total Adjustments to Current Income Taxes		(362,889)	(277,627)	28,897	(42,349)	(14,419)	(57,392)
					0		
DEFERRED INCOME TAXES					0		
Plant Additions - Adj. No. 20	41	1,109,616	610,389	95,907	219,547	41,252	142,518
Elimination of Closing/Filing - Adj. No. 23	24	(1,302,970)	(726,231)	(115,524)	(268,881)	(45,081)	(147,252)
Other Tax Deductions	24	38,579					
Total Adjustments to Deferred Income Taxes		(154,775)	(94,340)	(16,196)	(41,373)	(2,495)	(374)
					0		
Total Adjustments:		(2,001,276)	(1,243,842)	(87,267)	(377,430)	(67,704)	(225,032)

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		Total	Residential		
		Montana	Demand	Energy	Customer
		15,014,099	0	6,097,461	0
1	Dk Throughput	100.000000%	0.000000%	40.611567%	0.000000%
		93,245	48,732	0	0
2	1-Day Peak	100.000000%	52.262320%	0.000000%	0.000000%
		10,129,873	0	6,097,461	0
3	Dk Sales	100.000000%	0.000000%	60.192867%	0.000000%
		85,504	48,225	0	0
5	Peak Day @ Distribution	100.000000%	56.400869%	0.000000%	0.000000%
		78,910	0	0	70,161
8	Average Customers	100.000000%	0.000000%	0.000000%	88.912685%
		78,221	0	0	69,654
9	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	89.047698%
		98,843	0	0	70,161
10	Total Weighted Customers	100.000000%	0.000000%	0.000000%	70.982263%
		78,861	0	0	70,161
11	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	88.967931%
		96,691	0	0	69,654
12	Weighted Customers @ Distribution	100.000000%	0.000000%	0.000000%	72.037729%
		28,623,324	91,417	11,558,556	0
13	Distribution Mains	100.000000%	0.319381%	40.381599%	0.000000%
		71,677,695	10,708,204	12,480,887	15,435,411
15	Distribution Plant	100.000000%	14.939380%	17.412512%	21.534469%

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		Total	Small Firm General			Large Firm General		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		15,014,099	0	1,119,203	0	0	2,694,623	0
1	Dk Throughput	100.000000%	0.000000%	7.454347%	0.000000%	0.000000%	17.947284%	0.000000%
		93,245	10,098	0	0	20,435		
2	1-Day Peak	100.000000%	10.829535%	0.000000%	0.000000%	21.915384%	0.000000%	0.000000%
		10,129,873	0	1,119,203	0	0	2,694,623	0
3	Dk Sales	100.000000%	0.000000%	11.048539%	0.000000%	0.000000%	26.600758%	0.000000%
		85,504	10,068	0	0	20,290	0	0
5	Peak Day @ Distribution	100.000000%	11.774888%	0.000000%	0.000000%	23.729884%	0.000000%	0.000000%
		78,910	0	0	6,547	0	0	2,153
8	Average Customers	100.000000%	0.000000%	0.000000%	8.296794%	0.000000%	0.000000%	2.728425%
		78,221	0	0	6,517	0	0	2,008
9	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	8.331522%	0.000000%	0.000000%	2.567086%
		98,843	0	0	7,202	0	0	19,593
10	Total Weighted Customers	100.000000%	0.000000%	0.000000%	7.286303%	0.000000%	0.000000%	19.822345%
		78,861	0	0	6,547	0	0	2,153
11	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	8.301949%	0.000000%	0.000000%	2.730120%
		96,691	0	0	7,169	0	0	18,273
12	Weighted Customers @ Distribution	100.000000%	0.000000%	0.000000%	7.414341%	0.000000%	0.000000%	18.898346%
		28,623,324	19,085	2,121,599	0	38,462	5,108,020	0
13	Distribution Mains	100.000000%	0.066676%	7.412134%	0.000000%	0.134373%	17.845656%	0.000000%
		71,677,695	2,239,479	2,290,894	1,611,524	4,505,328	5,515,622	4,310,458
15	Distribution Plant	100.000000%	3.124374%	3.196104%	2.248292%	6.285537%	7.695033%	6.013667%

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		Total	Small Interruptible			Large Interruptible		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		15,014,099	0	904,879	0	0	4,197,933	0
1	Dk Throughput	100.000000%	0.000000%	6.026862%	0.000000%	0.000000%	27.959940%	0.000000%
		93,245	2,479	0	0	11,501	0	0
2	1-Day Peak	100.000000%	2.658588%	0.000000%	0.000000%	12.334173%	0.000000%	0.000000%
		10,129,873	0	218,586	0	0	0	0
3	Dk Sales	100.000000%	0.000000%	2.157836%	0.000000%	0.000000%	0.000000%	0.000000%
		85,504	2,007	0	0	4,914	0	0
5	Peak Day @ Distribution	100.000000%	2.347259%	0.000000%	0.000000%	5.747100%	0.000000%	0.000000%
		78,910	0	0	44	0	0	5
8	Average Customers	100.000000%	0.000000%	0.000000%	0.055760%	0.000000%	0.000000%	0.006336%
		78,221	0	0	39	0	0	3
9	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	0.049859%	0.000000%	0.000000%	0.003835%
		98,843	0	0	1,614	0	0	273
10	Total Weighted Customers	100.000000%	0.000000%	0.000000%	1.632893%	0.000000%	0.000000%	0.276196%
		78,861	0	0	0	0	0	0
11	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		96,691	0	0	1,431	0	0	164
12	Weighted Customers @ Distribution	100.000000%	0.000000%	0.000000%	1.479972%	0.000000%	0.000000%	0.169612%
		28,623,324	3,805	1,715,320	0	9,315	7,957,745	0
13	Distribution Mains	100.000000%	0.013293%	5.992735%	0.000000%	0.032543%	27.801610%	0.000000%
		71,677,695	561,895	1,852,197	367,601	1,145,390	8,592,745	60,060
15	Distribution Plant	100.000000%	0.783919%	2.584063%	0.512853%	1.597973%	11.988032%	0.083792%

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		Total	Residential		
		Montana	Demand	Energy	Customer
		20,137,238	5,257,521	0	7,648,998
16	Meters & Regulators	100.000000%	26.108451%	0.000000%	37.984345%
		225,230	538	68,039	0
17	Structures & Improvements	100.000000%	0.238867%	30.208676%	0.000000%
		576,181	1,840	232,671	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	0.319343%	40.381581%	0.000000%
		128,222	71	9,006	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	0.055372%	7.023756%	0.000000%
		2,019,419	517,917	0	753,501
20	Service Regulators	100.000000%	25.646832%	0.000000%	37.312762%
		187,826	467	58,959	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	0.248633%	31.390223%	0.000000%
		49,082,008	5,443,389	11,558,556	7,786,413
22	Mains & Services	100.000000%	11.090396%	23.549477%	15.864088%
		74,788,170	11,242,720	12,917,173	16,208,039
23	Pro Forma Distribution Plant	99.999999%	15.032753%	17.271679%	21.671929%
		42,846,655	6,597,238	7,754,484	9,529,554
24	Net Gas Plant in Service	100.000001%	15.397324%	18.098225%	22.241069%
		94,105,846	13,605,455	17,684,475	19,611,674
25	Total Gas Plant in Service	100.000000%	14.457607%	18.792111%	20.840017%
		58,923,014	7,485,900	22,897,748	5,346,268
26	Pro Forma Operating Revenue	100.000000%	12.704543%	38.860449%	9.073310%

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		Total	Small Firm General			Large Firm General		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		20,137,238	1,097,620	0	812,252	2,212,030	0	2,136,042
16	Meters & Regulators	100.000000%	5.450698%	0.000000%	4.033582%	10.984774%	0.000000%	10.607423%
		225,230	112	12,489	0	30,294	30,068	0
17	Structures & Improvements	100.000000%	0.049727%	5.544998%	0.000000%	13.450251%	13.349909%	0.000000%
		576,181	384	42,707	0	774	102,823	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	0.066646%	7.412081%	0.000000%	0.134333%	17.845608%	0.000000%
		128,222	3,928	1,653	0	30	3,980	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	3.063437%	1.289170%	0.000000%	0.023397%	3.103992%	0.000000%
		2,019,419	108,126	0	104,432	217,907	0	210,421
20	Service Regulators	100.000000%	5.354312%	0.000000%	5.171388%	10.790579%	0.000000%	10.419878%
		187,826	97	10,822	0	196	26,056	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	0.051644%	5.761716%	0.000000%	0.104352%	13.872414%	0.000000%
		49,082,008	1,136,424	2,121,599	799,272	2,290,230	5,108,020	2,174,416
22	Mains & Services	100.000000%	2.315358%	4.322560%	1.628442%	4.666129%	10.407113%	4.430169%
		74,788,170	2,351,070	2,370,975	1,690,833	4,730,217	5,708,428	4,526,220
23	Pro Forma Distribution Plant	99.999999%	3.143639%	3.170254%	2.260829%	6.324820%	7.632795%	6.052053%
		42,846,655	1,377,977	1,423,353	997,577	2,753,770	3,426,904	2,661,201
24	Net Gas Plant in Service	100.000001%	3.216067%	3.321970%	2.328249%	6.427036%	7.998067%	6.210989%
		94,105,846	2,845,401	3,246,025	2,047,544	5,724,306	7,815,220	5,476,710
25	Total Gas Plant in Service	100.000000%	3.023618%	3.449334%	2.175788%	6.082838%	8.304713%	5.819734%
		58,923,014	1,551,191	4,279,857	817,066	3,139,095	10,899,890	569,684
26	Pro Forma Operating Revenue	100.000000%	2.632572%	7.263473%	1.386667%	5.327452%	18.498528%	0.966828%

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		Total	Small Interruptible			Large Interruptible		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		20,137,238	218,804	0	188,481	535,727	0	29,763
16	Meters & Regulators	100.000000%	1.086564%	0.000000%	0.935982%	2.660380%	0.000000%	0.147801%
		225,230	24,633	10,097	0	2,117	46,843	0
17	Structures & Improvements	100.000000%	10.936820%	4.482973%	0.000000%	0.939928%	20.797851%	0.000000%
		576,181	77	34,529	0	188	160,188	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	0.013364%	5.992735%	0.000000%	0.032629%	27.801680%	0.000000%
		128,222	83,479	1,336	0	18,539	6,200	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	65.105052%	1.041943%	0.000000%	14.458517%	4.835364%	0.000000%
		2,019,419	21,554	0	29,855	52,774	0	2,932
20	Service Regulators	100.000000%	1.067337%	0.000000%	1.478396%	2.613326%	0.000000%	0.145190%
		187,826	8,180	8,750	0	33,707	40,592	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	4.355095%	4.658567%	0.000000%	17.945865%	21.611491%	0.000000%
		49,082,008	226,540	1,715,320	179,120	554,667	7,957,745	30,297
22	Mains & Services	100.000000%	0.461554%	3.494804%	0.364940%	1.130082%	16.213161%	0.061727%
		74,788,170	584,139	1,916,943	385,375	1,199,856	8,893,116	63,066
23	Pro Forma Distribution Plant	99.999999%	0.781058%	2.563163%	0.515289%	1.604339%	11.891073%	0.084326%
		42,846,655	305,616	948,624	228,176	702,945	4,102,156	37,080
24	Net Gas Plant in Service	100.000001%	0.713279%	2.213998%	0.532541%	1.640606%	9.574040%	0.086541%
		94,105,846	713,924	2,418,819	467,061	1,455,291	10,917,630	76,311
25	Total Gas Plant in Service	100.000000%	0.758639%	2.570317%	0.496315%	1.546441%	11.601437%	0.081091%
		58,923,014	85,870	1,214,641	87,000	0	517,004	31,800
26	Pro Forma Operating Revenue	100.000000%	0.145733%	2.061403%	0.147650%	0.000000%	0.877423%	0.053969%

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		Total	Residential		
		Montana	Demand	Energy	Customer
		2,068,721	196,249	316,945	664,805
27	All Other Dist. Operation Exp.	100.000000%	9.486488%	15.320819%	32.136040%
		622,292	74,728	72,426	217,988
28	All Other Dist. Maintenance Exp.	99.999996%	12.008510%	11.638588%	35.029856%
		4,322,876	432,124	630,127	1,414,486
29	Distribution O&M	100.000003%	9.996217%	14.576569%	32.720949%
		6,741,799	432,124	787,932	3,290,856
30	O&M Excl. Cost of Gas and A&G	100.000000%	6.409624%	11.687266%	48.812729%
		10,869,308	445,306	2,454,686	3,290,856
31	O&M Excl. Cost of Gas	100.000000%	4.096912%	22.583646%	30.276592%
		38,854,572	7,482,150	16,034,347	0
33	Cost of Gas	100.000000%	19.256807%	41.267595%	0.000000%
		(3,277,533)	(2,663,516)	2,909,906	(1,074,055)
35	Taxable Income	100.000002%	81.265879%	-88.783423%	32.770228%
		6,195,140	955,907	1,133,350	1,366,214
40	Total Tax Deductions & Adjustments	100.000000%	15.429950%	18.294179%	22.052996%
		100,463,466	14,245,129	18,288,135	22,730,963
41	Total Pro Forma Plant	100.000000%	14.179412%	18.203767%	22.626099%
		7,549,802	24,113	3,048,731	0
45	50% Dk Throughput - 50% Peak Day	100.000000%	0.319379%	40.381598%	0.000000%
		92,174	24,113	0	35,081
46	50% Wghtd Custs - 50% Peak Day	100.000000%	26.159904%	0.000000%	38.059204%

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		Total	Small Firm General			Large Firm General		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		2,068,721	40,970	58,177	68,603	82,570	140,065	185,652
27	All Other Dist. Operation Exp.	100.000000%	1.980451%	2.812221%	3.316204%	3.991355%	6.770609%	8.974241%
		622,292	15,602	13,294	22,759	31,599	32,007	60,875
28	All Other Dist. Maintenance Exp.	99.999996%	2.507183%	2.136296%	3.657286%	5.077841%	5.143405%	9.782385%
		4,322,876	90,214	115,664	146,335	182,033	278,468	395,007
29	Distribution O&M	100.000003%	2.086898%	2.675626%	3.385131%	4.210923%	6.441730%	9.137597%
		6,741,799	90,214	144,630	322,954	182,033	348,207	493,281
30	O&M Excl. Cost of Gas and A&G	100.000000%	1.338129%	2.145273%	4.790324%	2.700066%	5.164897%	7.316756%
		10,869,308	92,966	450,567	322,954	187,579	1,084,788	493,281
31	O&M Excl. Cost of Gas	100.000000%	0.855307%	4.145314%	2.971247%	1.725768%	9.980286%	4.538293%
		38,854,572	1,550,414	2,766,094	0	3,137,522	7,255,016	0
33	Cost of Gas	100.000000%	3.990300%	7.119095%	0.000000%	8.075039%	18.672232%	0.000000%
		(3,277,533)	(556,121)	614,119	162,483	(1,117,401)	1,786,305	(765,652)
35	Taxable Income	100.000002%	16.967671%	-18.737233%	-4.957479%	34.092746%	-54.501511%	23.360619%
		6,195,140	199,646	207,790	143,018	399,027	501,084	381,525
40	Total Tax Deductions & Adjustments	100.000000%	3.222623%	3.354081%	2.308552%	6.440968%	8.088340%	6.158456%
		100,463,466	2,978,985	3,356,829	2,347,510	5,993,439	8,081,993	5,802,162
41	Total Pro Forma Plant	100.000000%	2.965242%	3.341343%	2.336680%	5.965790%	8.044709%	5.775395%
		7,549,802	5,034	559,602	0	10,145	1,347,312	0
45	50% Dk Throughput - 50% Peak Day	100.000000%	0.066677%	7.412135%	0.000000%	0.134374%	17.845655%	0.000000%
		92,174	5,034	0	3,601	10,145	0	9,797
46	50% Wghtd Custs - 50% Peak Day	100.000000%	5.461440%	0.000000%	3.906763%	11.006417%	0.000000%	10.628326%

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		Total	Small Interruptible			Large Interruptible		
		Montana	Demand	Energy	Customer	Demand	Energy	Customer
		2,068,721	8,798	47,035	15,459	22,599	218,207	2,587
27	All Other Dist. Operation Exp.	100.000000%	0.425287%	2.273627%	0.747273%	1.092414%	10.547918%	0.125053%
		622,292	3,922	10,748	5,191	10,442	49,863	848
28	All Other Dist. Maintenance Exp.	99.999996%	0.630251%	1.727163%	0.834174%	1.677990%	8.012798%	0.136270%
		4,322,876	20,176	93,512	33,062	52,340	433,823	5,505
29	Distribution O&M	100.000003%	0.466726%	2.163190%	0.764815%	1.210768%	10.035518%	0.127346%
		6,741,799	20,176	99,169	37,806	52,340	433,823	6,254
30	O&M Excl. Cost of Gas and A&G	100.000000%	0.299267%	1.470958%	0.560770%	0.776351%	6.434825%	0.092765%
		10,869,308	20,725	346,520	37,806	53,683	1,581,337	6,254
31	O&M Excl. Cost of Gas	100.000000%	0.190675%	3.188059%	0.347823%	0.493895%	14.548645%	0.057538%
		38,854,572	91,968	537,061	0	0	0	0
33	Cost of Gas	100.000000%	0.236698%	1.382234%	0.000000%	0.000000%	0.000000%	0.000000%
		(3,277,533)	(125,838)	72,666	(22,949)	(267,253)	(2,255,001)	24,774
35	Taxable Income	100.000002%	3.839412%	-2.217094%	0.700191%	8.154090%	68.801779%	-0.755873%
		6,195,140	43,939	136,724	32,713	100,778	588,109	5,316
40	Total Tax Deductions & Adjustments	100.000000%	0.709250%	2.206956%	0.528043%	1.626727%	9.493070%	0.085809%
		100,463,466	741,686	2,503,360	489,822	1,521,006	11,302,385	80,062
41	Total Pro Forma Plant	100.000000%	0.738264%	2.491811%	0.487562%	1.513989%	11.250244%	0.079693%
		7,549,802	1,004	452,440	0	2,457	2,098,967	0
45	50% Dk Throughput - 50% Peak Day	100.000000%	0.013292%	5.992734%	0.000000%	0.032544%	27.801612%	0.000000%
		92,174	1,004	0	807	2,457	0	137
46	50% Wghtd Custs - 50% Peak Day	100.000000%	1.088708%	0.000000%	0.875523%	2.665625%	0.000000%	0.148090%

MDU's Montana Non-Gas Revenues At Current And MDU-Proposed Rates

Line No.	Customer Class	Total Revenues Present Rates	Gas Cost Revenues Present Rates	Non-Gas Revenues Present Rates	MDU's Proposed Increase Total	% Of Total	% Increase
1	Residential	$ 35,729,916	$ 23,516,497	$ 12,213,419	$ 2,836,325	82.0%	23.2%
2							
3	Gen Service-Small Firm	$ 6,648,114	$ 4,316,508	$ 2,331,606			
4	Gen Service-Large Firm	$ 14,608,669	$ 10,392,538	$ 4,216,131			
5	Total General Service	$ 21,256,783	$ 14,709,046	$ 6,547,737	$ 594,426	17.2%	9.1%
6							
7	Small Interruptible	$ 1,387,511	$ 629,029	$ 758,482	$ 19,161	0.6%	2.5%
8							
9	Large Interruptible	$ 548,804	$ -	$ 548,804	$ 7,500	0.2%	1.4%
10							
11	Total Montana	$ 58,923,014	$ 38,854,572	$ 20,068,442	$ 3,457,412	100.0%	17.2%

Sources: MDU Exhibit ___ (TAA-1), page 2, and Statement L, Schedule L-1, pages 1-3.

Alternative Proposed Customer Class Non-Gas Revenues At MDU's And MCC's Proposed Revenue Increases

Line No.	MDU Proposal Customer Class	Revenue At Present Rates	Revenue At MDU's Total Revenue & MDU's Proposed Class Revenue	Increase Proposed By MDU	Percent Increase
1	Residential	$ 12,213,419	$ 15,049,744	$ 2,836,325	23.22%
2	Small General Svc.	$ 2,331,606			
3	Large General Svc.	$ 4,216,131			
4	Total General Service	$ 6,547,737	$ 7,142,163	$ 594,426	9.08%
5	Small Interruptible	$ 758,482	$ 777,643	$ 19,161	2.53%
6	Large Interruptible	$ 548,804	$ 556,304	$ 7,500	1.37%
7	Total	$ 20,068,442	$ 23,525,854	$ 3,457,412	17.23%

Line No.	MCC Alternative 1 Customer Class	Revenue At Present Rates	Revenue At MDU's Total Revenue & MCC's Proposed Class Revenue	Increase Proposed By MCC	Percent Increase
8	Residential	$ 12,213,419	$ 14,289,700	$ 2,076,281	17.00%
9	Small General Svc.	$ 2,331,606	$ 2,716,321	$ 384,715	16.50%
10	Large General Svc.	$ 4,216,131	$ 4,932,873	$ 716,742	17.00%
11	Total General Service	$ 6,547,737	$ 7,649,194	$ 1,101,457	
12	Small Interruptible	$ 758,482	$ 887,424	$ 128,942	17.00%
13	Large Interruptible	$ 548,804	$ 699,176	$ 150,372	27.40%
14	Total	$ 20,068,442	$ 23,525,495	$ 3,457,053	17.23%

Line No.	MCC Alternative 2 Customer Class	Revenue At Present Rates	Revenue At MCC's Total Revenue & MCC's Proposed Class Revenue	Increase Proposed By MCC	Percent Increase
15	Residential	$ 12,213,419	$ 12,466,849	$ 253,430	2.08%
16	Small General Svc.	$ 2,331,606	$ 2,378,564	$ 46,958	2.01%
17	Large General Svc.	$ 4,216,131	$ 4,303,616	$ 87,485	2.08%
18	Total General Service	$ 6,547,737	$ 6,682,180	$ 134,443	
19	Small Interruptible	$ 758,482	$ 774,221	$ 15,739	2.08%
20	Large Interruptible	$ 548,804	$ 567,158	$ 18,354	3.34%
21	Total	$ 20,068,442	$ 20,490,408	$ 421,966	2.10%

22	Scale-back factor for MCC Alternative 2 proposed revenue increase (Col. 5, L.21 divided by Col.5, L.14).	12.21%

Comparison Of Annual Residential Customer Delivery Charges Under Alternative Service Charges - Present And MDU Proposed Total Non-Gas Revenues

Present Revenues And Rate Design

Annual Dkt	Service Charges Monthly	Service Charges Annual	Commodity Charges Rate/Dkt	Commodity Charges Annual	Total Revenue	Increase	Percent Increase	Average Revenue
35	$ 6.35	$ 76.20	$ 1.126	$ 39.41	$ 115.61	NA	NA	$ 3.30
50	$ 6.35	$ 76.20	$ 1.126	$ 56.30	$ 132.50	NA	NA	$ 2.65
70	$ 6.35	$ 76.20	$ 1.126	$ 78.82	$ 155.02	NA	NA	$ 2.21
90	$ 6.35	$ 76.20	$ 1.126	$ 101.34	$ 177.54	NA	NA	$ 1.97
110	$ 6.35	$ 76.20	$ 1.126	$ 123.86	$ 200.06	NA	NA	$ 1.82
130	$ 6.35	$ 76.20	$ 1.126	$ 146.38	$ 222.58	NA	NA	$ 1.71
150	$ 6.35	$ 76.20	$ 1.126	$ 168.90	$ 245.10	NA	NA	$ 1.63
175	$ 6.35	$ 76.20	$ 1.126	$ 197.05	$ 273.25	NA	NA	$ 1.56

MDU's Proposed Revenues And Service Charge

Annual Dkt	Service Charges Monthly	Service Charges Annual	Commodity Charges Rate/Dkt	Commodity Charges Annual	Total Revenue	Increase	Percent Increase	Average Revenue
35	$ 10.64	$ 127.68	$ 0.999	$ 34.97	$ 162.65	$ 47.04	40.7%	$ 4.65
50	$ 10.64	$ 127.68	$ 0.999	$ 49.95	$ 177.63	$ 45.13	34.1%	$ 3.55
70	$ 10.64	$ 127.68	$ 0.999	$ 69.93	$ 197.61	$ 42.59	27.5%	$ 2.82
90	$ 10.64	$ 127.68	$ 0.999	$ 89.91	$ 217.59	$ 40.05	22.6%	$ 2.42
110	$ 10.64	$ 127.68	$ 0.999	$ 109.89	$ 237.57	$ 37.51	18.7%	$ 2.16
130	$ 10.64	$ 127.68	$ 0.999	$ 129.87	$ 257.55	$ 34.97	15.7%	$ 1.98
150	$ 10.64	$ 127.68	$ 0.999	$ 149.85	$ 277.53	$ 32.43	13.2%	$ 1.85
175	$ 10.64	$ 127.68	$ 0.999	$ 174.83	$ 302.51	$ 29.26	10.7%	$ 1.73

MDU's Proposed Revenues And Present Service Charge

Annual Dkt	Service Charges Monthly	Service Charges Annual	Commodity Charges Rate/Dkt	Commodity Charges Annual	Total Revenue	Increase	Percent Increase	Average Revenue
35	$ 6.35	$ 76.20	$ 1.591	$ 55.69	$ 131.89	$ 16.28	14.1%	$ 3.77
50	$ 6.35	$ 76.20	$ 1.591	$ 79.55	$ 155.75	$ 23.25	17.5%	$ 3.12
70	$ 6.35	$ 76.20	$ 1.591	$ 111.37	$ 187.57	$ 32.55	21.0%	$ 2.68
90	$ 6.35	$ 76.20	$ 1.591	$ 143.19	$ 219.39	$ 41.85	23.6%	$ 2.44
110	$ 6.35	$ 76.20	$ 1.591	$ 175.01	$ 251.21	$ 51.15	25.6%	$ 2.28
130	$ 6.35	$ 76.20	$ 1.591	$ 206.83	$ 283.03	$ 60.45	27.2%	$ 2.18
150	$ 6.35	$ 76.20	$ 1.591	$ 238.65	$ 314.85	$ 69.75	28.5%	$ 2.10
175	$ 6.35	$ 76.20	$ 1.591	$ 278.43	$ 354.63	$ 81.38	29.8%	$ 2.03

Present Revenues & Rates		**Rate**	**Revenue**
Number Of Customers	70,161	$ 6.35	$ 5,346,268
Annual Dkt	6,097,461	$ 1.126	$ 6,867,151
Total Revenues			$ 12,213,419

MDU's Proposed Revenues & Rates		**Rate**	**Revenue**
Number Of Customers	70,161	$ 10.64	$ 8,958,156
Annual Dkt	6,097,461	$ 0.999	$ 6,091,588
Total Revenues			$ 15,049,744

MDU Proposed Revenue & Current Service Charge		**Rate**	**Revenue**
Number Of Customers	70,161	$ 6.35	$ 5,346,268
Annual Dkt	6,097,461	$ 1.591	$ 9,703,476
Total Revenues			$ 15,049,744

MDU'S MONTANA CUSTOMER-RELATED NATURAL GAS OPERATION & MAINTENANCE EXPENSES
2007 - 2011

Description	2007	2008	2009	2010	2011
Distribution Operation					
Meters & House Regulators	$ 283,849	$ 289,540	$ 343,353	$ 391,269	$ 267,551
Customer Installations	$ 746,562	$ 836,606	$ 507,304	$ 517,434	$ 538,992
Distribution Maintenance					
Services	$ 113,980	$ 183,513	$ 191,693	$ 160,415	$ 155,111
Meters & House Regulators	$ 182,990	$ 295,566	$ 313,723	$ 268,882	$ 284,028
Total Distribution O & M	$ 1,327,381	$ 1,605,225	$ 1,356,073	$ 1,338,000	$ 1,245,682
Customer Accounts 1/					
Meter Reading	$ 641,359	$ 454,619	$ 283,679	$ 258,366	$ 230,640
Customer Records & Collection	$ 1,204,033	$ 1,212,362	$ 1,233,627	$ 1,221,296	$ 1,376,127
Miscellaneous	$ 137,923	$ 129,481	$ 139,223	$ 86,442	$ 71,102
Total Customer Accounts	$ 1,983,315	$ 1,796,462	$ 1,656,529	$ 1,566,104	$ 1,677,869
Customer Service & Information					
Customer Assistance	$ 10,044	$ 13,500	$ 12,283	$ 9,092	$ 11,125
Inform. & Instruc. Advertising	$ 47,465	$ 50,339	$ 13,276	$ 17,436	$ 29,420
Miscellaneous	$ 237	$ 85	$ 63	$ 166	$ 20,025
Total Cust. Svc. & Info.	$ 57,746	$ 63,924	$ 25,622	$ 26,694	$ 60,570
Total Customer-Related Operation & Maintenance Expenses	$ 3,368,442	$ 3,465,611	$ 3,038,224	$ 2,930,798	$ 2,984,121
Total Customers	76,262	77,090	77,750	78,450	79,118
Customer-Related Operation & Maint. Expenses Per Customer:					
Total	$ 44.17	$ 44.96	$ 39.08	$ 37.36	$ 37.72
Monthly	$ 3.68	$ 3.75	$ 3.26	$ 3.11	$ 3.14

1/ Excluded uncollectible accounts expenses because they are revenue-related expenses.

Source: MDU's Annual Reports to the Montana Public Service Commission, for 2007 - 2011.

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA
* * * * *

IN THE MATTER OF the Application of	)	REGULATORY DIVISION
MONTANA-DAKOTA UTILITIES CO.	)	
A Division of MDU Resources Group,	)	DOCKET NO. D2012.9.100
Inc., for Authority to Establish Increased	)	
Rates for Natural Gas Service	)	

Direct Testimony
of
John W. Wilson
on Behalf
of
The Montana Consumer Counsel

February 25, 2013

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QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 1601 North Kent Street, Suite 1104, Arlington, Virginia, 22209.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a PhD in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught courses in both economics and government. While at West Point, I also served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission (now known as the Federal Energy Regulatory Commission or

(FERC), first as a staff economist and then as Chief of the Commission's Division of Economic Studies. In that capacity, I was involved in regulatory matters involving most phases of federal regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients, including federal, state, provincial and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public utility regulation, insurance rate regulation, antitrust matters and economic and financial analysis. In 1975 I formed J.W. Wilson & Associates, Inc., a Washington, D.C. corporation.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with utility regulation and economic policy. I have consulted on regulatory, financial and competitive market matters with the Federal Communications Commission (FCC), the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute (NRRI), the Electric Power Research Institute (EPRI), the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute (EEI), The American Public Power Association (APPA), the National Rural Electric Cooperative Association (NRECA), the U.S.

Department of Justice Antitrust Division, the Federal Trade Commission Bureau of Competition, the Commerce Department, the Department of the Interior, the Department of Energy (DOE), the Small Business Administration (SBA), the Department of Defense (DOD), the Tennessee Valley Authority (TVA), the Internal Revenue Service (IRS), the Federal Energy Administration (FEA), and numerous state and provincial agencies and legislative bodies in the United States and Canada.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, the FPC Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey, the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment Income, and the NAIC's Advisory Committee on Nuclear Risks.

In addition, I have testified as an expert witness in state and federal court proceedings dealing with many economic matters, including utility rates and competition in the electric power industry and on other regulatory matters before more than 50 Federal and State regulatory bodies throughout the United States and Canada. I have also appeared on numerous occasions as an expert witness at the invitation of U.S. Senate and Congressional Committees dealing with antitrust and regulatory legislation. In addition, I have been retained as an expert on regulatory matters by more than 25 State

and Federal regulatory agencies. I have also participated as a speaker, panelist, or moderator in many professional conferences and programs dealing with business regulation, financial issues, economic policy and antitrust matters. I am a member of the American Economic Association and an associate member of the American Bar Association and the ABA's Antitrust, Insurance and Regulatory Law Sections.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am presenting testimony in this proceeding on behalf of the Montana Consumer Counsel (MCC). I have been asked by the MCC to review and address Montana Dakota Utilities Company's (MDU or the Company) proposals in this case concerning rate of return.

SUMMARY

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN TESTIMONY.

A. My rate of return testimony in this case deals with MDU's requested rate of return on rate base. My analysis concerning MDU's rate of return focuses primarily on the Company's cost of common equity capital.

While MDU is requesting a common equity return allowance of 10.5

percent, the evidence that I present shows that a more reasonable equity return allowance, under present financial circumstances, would be in the 7.0 to 9.0 percent range. Especially in view of the decline in interest rates and other money costs that has occurred in recent years, a 10.5 percent equity return allowance would not be just and reasonable in this case. Combining a 9.0 percent return on common equity (ROE) with the Company's debt and preferred stock costs and an appropriate capital structure, I recommend an overall rate of return on rate base of 7.615 percent in this case.

Q. WHAT IS RATE OF RETURN?

A. Rate of return is often described as the profit, expressed as a percentage of the invested capital (measured as rate base), that the utility is allowed to include in its rates. From an economist's perspective it is not quite right to call this allowed "profit" because it includes both the cost of debt capital (interest expense) as well as the allowed return on equity investment. If a utility has $100 million invested in rate base and this is funded with $50 million of debt, with an average interest rate of 6 percent, and $50 million of equity, which the Commission has determined requires a return of 10 percent (cost of equity or ROE), the allowed rate of return would be 8 percent or $8 million annually. This amount, along with all expenses and taxes, would be the revenue requirement reflected in the utility's rates.

Q. IS THE DETERMINATION OF A UTILITY'S RATE OF RETURN ALLOWANCE A CONTROVERSIAL ASPECT IN MOST RATE CASES?

A. Yes. Rate of return accounts for a substantial portion of a utility's rates. While the debt component of rate of return is usually a straightforward measure of a Company's actual interest costs as reflected on its books, the equity return component is largely a matter of judgment and is typically hotly contested.

While rate of return analysts may be able to offer the Commission facts, analyses and insights that will help to inform a reasonable range within which that essential judgment can be exercised, it is ultimately a determination that must depend on the Commission's priorities, objectives and exercise of discretion, which no model, set of "expert" calculations, or sworn opinions can replace.

THE DCF MODEL

Q. DO YOU DISAGREE WITH THE DESCRIPTION OF THE DISCOUNTED CASH FLOW (DCF) MODEL THAT THE COMPANY'S WITNESS, DR. GASKE, HAS PRESENTED IN HIS DIRECT TESTIMONY?

A. No. While I am in agreement with Dr. Gaske's basic description of the model, as explained below, I do not agree with his .625g adjustment to the dividend yield or with his 4.0 percent flotation cost adjustment. I also disagree with Dr. Gaske's apparent rejection of the overall results of his own DCF cost of common equity capital analysis, which indicates median cost of common equity results in the 8 to 9 percent range, and with his proposed alternative 10.5 percent return on equity (ROE) allowance, reflecting his calculated DCF result for only the single highest cost company in his comparable gas utility group.[1]

Q. IS STRICT ADHERENCE TO THE RESULTS OF MODELS ESSENTIAL TO GETTING THE RATE OF RETURN "RIGHT" IN A REGULATORY PROCEEDING LIKE THIS?

A. No. Models can be either helpful or confusing, and their results are highly

[11] The single company that Dr. Gaske relies on for his ROE recommendation in this case, South Jersey Industries, differs from his other comparable gas utilities not only in that it produces his single highest cost of capital estimate, but that it also derives an exceptionally high percentage of its income from its non-utility affiliates.

dependent on implementation. Ultimately, the "right" ROE determination in this (and any) rate case is largely a matter of informed judgment. While "experts" may be able to offer the Commission facts, analyses and insights that will help to inform a reasonable range within which that essential judgment can be exercised, it is ultimately a determination that must depend on the Commission's priorities, objectives and exercise of discretion, which no model, set of "expert" calculations, or sworn opinions can replace.

Q. PLEASE DESCRIBE THE DCF MODEL.

A. Discounted cash flow (DCF) models are frequently used as a method for measuring the cost of, or required return on, a firm's common equity capital. The DCF model is based upon two fundamental principles. First, it is based on the principle that rational investors evaluate the risks and expected returns of securities in capital markets and establish a price for a particular security which adequately compensates them for the risks they perceive. Second, the model is based on the proposition that the total return received by shareholders consists of dividends and capital gains, and these are measured in terms of the current dividend yield plus the expected rate of dividend growth. The DCF model, which combines yield and growth information to produce the total return expected by investors, is the following:

$$\text{Total Return to Investor} = \text{Current Dividend Yield} + \text{Expected Dividend Growth Rate}$$

The model makes no separate provision for capital gains because they are fully accounted for in the growth component. That is, capital gains are a consequence of price appreciation which, in turn, is a consequence of rising dividends and expected dividend growth.

Since an individual investor cannot control either the current dividend rate or the dividend growth rate, his decision about the adequacy of returns is reflected by his buy, sell, and hold decisions. If the expected return exceeds the required return, the price of common stock will be greater than the stock's book value. If the expected return is lower than investor requirements, the market price will fall below book value. If investor expectations and requirements are the same, the stock will trade at a price equal to book value.

In other words, the DCF procedure for estimating the cost of equity capital reflects the fact that the maximum price a logical investor will pay for a security is an amount equal to the present value of the dividends that he or she expects to receive over the years during which the security is held plus its resale price, including capital gains, when the security is sold. Algebraically, this observation can be represented by the following equation:

$$Po = \frac{D_1}{1 + R} + \frac{D_2}{(1+R)^2} + \ldots + \frac{D_t}{(1+R)^t} + \frac{P_t}{(1+R)^t}$$

where Po is the price of a company's common stock today; D1, D2 ... Dt are expected dividends in subsequent periods; Pt is the expected resale price of the stock at some time in the future; and R is the discount rate or required return (sometimes referred to as the opportunity cost of capital). This algebraic statement, becomes an infinite geometric progression (because P_t and all subsequent resale values depend on expected dividends and resale prices at that point in the future, and dividends are assumed to grow at a constant annual rate) which reduces algebraically to the familiar DCF formula:

$$R = D/P + g$$

where g is the expected annual rate of dividend growth.

The market price is the present value of all cash flows expected in the future, discounted at a rate equal to the rate of return investors require on the investment. Present value is the current worth of expected future returns – that is, what an investor would be willing to pay today in order to obtain the expected cash flows in the future. Today's price is the present value of these expected cash flows, discounted at a rate that reflects the cost

of capital, including the risk perceived by investors that their expectations will not be met.

The most controversial aspect of DCF analysis is usually estimating the growth component of the model, rather than the underlying model or theory, itself.

Q. WHAT EXPECTATIONS ARE IMPORTANT IN DCF ANALYSIS?

A. Investors' collective expectations are central to the discounted cash flow approach and are the key to establishing the cost of common equity capital. While analysts may opine on what they think investor expectations may be, the only way in which investors reveal their collective expectations is in the market prices that they establish for common stock. Investors establish prices for common stocks on the basis of their collective expectations of future income streams (dividends and capital gains) relative to their return requirements for the level of perceived risk. It is the consensus of investor expectations that establishes the price of common equities, and those expectations are ultimately concerned with investors' expected future income stream (i.e, dividends). This means that it is the expected future growth in dividends, which is most important.

Although dividend yields are easy to estimate with published data, the expected growth component is not as easy. Analysts often publish their

expectations, which, overall, tend to be somewhat bullish, but there is no published consensus value for the generally more conservative expectations investors hold. That analysts' forecasts are somewhat more bullish than investors' actual expectations is evident from a number of observations, including stock market prices which are typically somewhat lower than analysts price forecasts. Really valuable analysts are those who know something that the market does not already know. In seeking an equity cost rate one must determine, on the basis of factual information, what the most reasonable estimate of growth expectations held by investors is at any point in time.

In this regard, it is important to emphasize that the task of the rate of return analyst is to determine what growth rate investors are expecting, and not to forecast the actual growth rate the analyst expects. Nor does it matter whether investors' expectations turn out to be right or wrong. Today's common stock prices, which enter the DCF calculation through the dividend yield term, depend upon today's expectations for future growth. Of course, expectations and requirements may be different at different times, and therefore the cost of common equity is likely to change over time. For example, when interest rates are very high, it is likely that required equity returns are higher than when, as now, interest rates are low. Similarly, when expected long-term inflation rates are high, it is likely that

the cost of common equity will be higher than when long-term inflation expectations are low. A cost of common equity established at one point in time may be quite different from that established previously, or that found to be true in the future. Also, while tomorrow's hindsight may prove that today's expectations were wrong, that does not and cannot possibly affect today's cost of capital. That is why it is necessary only for the rate of return analyst to estimate, as accurately as possible, what present investor expectations actually are, and not whether they are correct.

<u>DR. GASKE'S DCF CALCULATIONS</u>

Q. DO YOU AGREE WITH DR. GASKE'S DCF CALCULATIONS?

A. I have some disagreements with his specific calculations.

Q. WHAT ARE YOUR DISAGREEMENTS WITH DR GASKE'S DCF CALCULATIONS?

A. First, Dr. Gaske essentially ignores his own DCF results for all but the single highest cost company in his comparable gas utility group, and he did not incorporate the lower DCF results for any of his other companies in arriving at his recommendation. Instead of evenhandedly considering all of his results, Dr. Gaske based his ROE recommendation only the calculated

result for his single highest cost company. This procedure obviously biases his conclusions by restricting reference to only the highest result of his DCF calculations. This is entirely unreasonable in an objective and even-handed evaluation of capital costs. Setting aside all results except for his highest cost company, Dr. Gaske selects 10.5 percent as his ROE recommendation. Had he included all of his calculated results in deriving his recommendation, his median result would have been in the 8 to 9 percent range.

Moreover, the single highest cost company that Dr. Gaske relies on, South Jersey Industries (SJI), is substantially involved in non-utility businesses with entirely different risks than those faced by a regulated gas distribution utility.[2] In 2010 and 2011 SJI's non-utility income from continuing operations was 35% and 41%, respective, of the Company's total earnings, and non-utility "economic" earnings were 46% and 39 %, respectively, of the Company's total economic earnings.

Second, in addition to earnings growth per share (which Dr. Gaske relies on exclusively in his DCF calculations), consideration should also be given to growth in book value per share and growth in dividends per share. Expected dividend growth is particularly important because dividend yield

[2] I am, of course, aware that MDU Resources is also substantially involved in non-utility businesses. However this case involves the cost of capital and an allowed ROE for only the Company's regulated gas distribution business in Montana, and not for its other unregulated competitive businesses.

and dividend growth are the expected payouts relevant to investors. Expected earnings growth and expected book value growth are relevant as determinants of, and therefore proxies for, expected dividend growth.

Q. WHAT OTHER SPECIFIC DISAGREEMENTS DO YOU HAVE WITH DR. GASKE'S COST OF EQUITY ANALYSIS THAT SHOULD BE NOTED?

A. I also disagree with his .625g adjustment to the dividend yield component of the DCF model. This adjustment, as explained by Dr. Gaske at JSG-1, page14, is based on the premise that the dividend in the yield component of his model is a dividend payment that investors expect to start growing on a quarterly basis during the first year reflected in the DCF calculation. While it may be reasonable to expect some dividend growth during this first year reflected in the calculation if the dividend value used in the calculation is the actual historic dividend paid in the prior year, it is not reasonable if the dividend value used is the current "declared" dividend that is expected to be paid during the current year. In this case, the dividend yield that Dr. Gaske uses in his DCF calculation is apparently the dividend that Bloomberg expects to be paid in 2012, divided by the Company's historic stock price for the period from January, 2012 through June, 2012 (see JSG-2, schedule 2, page 3). Thus, Dr. Gaske's DCF calculation relates the dividend declared for payment in the future to an historic price, and the dividend in

relation to price is therefore already forward looking so that the first year's growth is already reflected in the dividend yield calculation. Consequently, the dividend payment component of the model (the declared dividend) is already more than sufficiently forward looking in relation to the stock price (an historic price beginning at the start of the year) used in the yield calculation. Dr. Gaske's .625g adjustment therefore overstates the reasonably expected dividend yield in the first year of his DCF calculation. Further, at least some of Dr. Gaske's comparable gas utilities do not increase their dividends in each year.

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

A. Yes. I also disagree with his flotation cost adjustment. That is, while actual flotation costs are part of the cost of capital, assuming a flotation cost of 4 percent for all of MDU's common equity capital, as Dr. Gaske does, greatly overstates MDU's actual common stock issuance costs.

In the case of debt, actual issuance or flotation costs are incorporated into the capital cost computation by relating the actual proceeds from debt issuances (e.g., the face amount of bonds less actual issuance costs) to interest payment obligations. Thus, if a company issues $100 million of debt at a 6 percent interest rate and has actual proceeds of $99 million (i.e.,

issuance costs are $1 million) the embedded cost of debt is 6.06 percent (6/99) and not 6.00 percent (6/100).

In the case of common equity, the great preponderance of equity growth for gas distribution utilities (including MDU) is retained earnings - not new public stock issuances. Retained earnings (and other forms of raising common equity capital, such as dividend reinvestment plans and parent company equity infusions out of parent retained earnings), do not have the issuance costs that Dr. Gaske assumes.

Especially in the case of MDU's Montana operations, which have generated substantial retained earnings but have grown little during the past several decades (and for which there are modest future growth expectations), there is no realistic basis for the flotation cost adjustment that Dr. Gaske proposes.

CORRECTED DCF RESULTS

Q. PLEASE DESCRIBE YOUR OWN DCF COST OF EQUITY ESTIMATES.

A. DCF cost of equity indications are presented in Exhibits___(JWW-1) through (JWW-4). In each case, the reported dividend yields are Value

Line's recently reported declared dividend yield for each company. These reflect the dividends currently declared to be paid in the future, divided by each company's recent market price of common stock.

Q. PLEASE SUMMARIZE EXHIBIT ___(JWW-1).

A. Exhibit___(JWW-1) provides DCF model results based on projected earnings growth for the same comparable gas distribution utility companies as those used by Dr. Gaske. These results reflect Value Line dividend yield values as described above plus the average of Value Line and Zacks growth forecasts. The average indicated ROE estimate is 8.9 percent, while the median ROE estimate is 9.0 percent.

Q. HAVE YOU PERFORMED ANY ADDITIONAL DCF CALCULATIONS?

A. Yes. I performed the same DCF calculations using projected dividends and book value growth, rather than projected earnings growth, and I have also made a fundamental DCF analysis.

Q. DID DR. GASKE ALSO CALCULATE ROE ESTIMATES BASED ON DIVIDEND AND BOOK VALUE GROWTH?

A. No. Despite the fact that the DCF model is explicitly designed to estimate common equity cost based on stock prices and investors' dividend

expectations (dividend yield plus dividend growth), Dr. Gaske elected to consider only earnings forecasts (as a proxy for dividend growth) rather than considering dividend growth forecasts directly.

While I do not contend that dividend or book value growth results are necessarily superior in this case to the earnings growth indications in Exhibit___(JWW-1), I present them here for the Commission's consideration in Exhibits___(JWW-2) and (JWW-3). The results for these additional DCF calculations are in the 7.15 to 8.07 percent range for the dividend growth model and in the 8.45 to 9.30 percent range for the book value growth model as shown in Exhibits___(JWW-2) and (JWW-3), respectively.

Q. HAVE YOU ALSO PERFORMED A FUNDAMENTAL DCF ANALYSIS?

A. Yes, I have.

Q. WHAT IS A FUNDAMENTAL DCF CALCULATION?

A. A fundamental DCF calculation uses retained earnings as the measure of expected growth. Because retained earnings provide for growth in equity and growth in equity provides for business growth, the rate of earnings plow-back (i.e., those earnings not paid out in dividends) serves as a basis for estimating future dividend growth. If the funds that are retained and

reinvested earn the allowed return and the allowed return is equal to the cost of capital, retained earnings provide a good estimate of future growth.

For example, if a company with a stock price and book value of $50 per share earns $5.00 (10 percent) and pays out a dividend of $2.50, its dividend yield is 5 percent (i.e., 2.50/50). Expected growth will also be 5 percent because, if the 10 percent earnings rate is maintained, the $2.50 that is retained will permit earnings to increase by that amount (i.e., $2.50 x 10 percent = $0.25, which is 5 percent of $5.00). Likewise, the retention of $2.50 of earnings within the corporation will cause the book value of its stock to increase by 5 percent (i.e., $2.50 is 5 percent of $50.00). In this case, the dividend yield of 5 percent plus expected growth of 5 percent equals 10 percent, which is the cost of capital.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR FUNDAMENTAL DCF CALCULATION.

A. The results of my fundamental DCF calculations for the comparable gas distribution companies are presented in Exhibit___(JWW-4). Both the dividend yield and retained earnings percentages reflect Value Line's projections for the future. The results are similar to Dr. Gaske's retention growth DCF calculations, except that I have not included his .625g dividend yield adjustment nor his flotation cost adjustment. The average

result for my fundamental DCF model is 8.96 percent and the median is 8.55 percent. The Commission may, of course, give whatever weight it deems appropriate to the DCF results shown in Exhibits__(JWW-1) through (JWW-4), as they all lie within a reasonable range. The average indication of these DCF results is 8.5 percent.

<u>CAPITAL ASSET PRICING MODEL</u>

Q. HAVE YOU ALSO PERFORMED CAPITAL ASSET PRICING MODEL CALCULATIONS TO ESTIMATE THE COST OF EQUITY CAPITAL?

A. Yes; I have.

Q. DID DR. GASKE PRESENT A CAPITAL ASSET PRICING MODEL?

A. No.

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL (CAPM).

A. The CAPM is, like the DCF model, one of the most widely used techniques to estimate the cost of equity capital. The fundamental principle underlying

the CAPM is that investors require compensation for risk when making an investment – that is, they require a higher return than is required for a riskless investment. In other words, while the DCF model estimates the cost of equity capital directly by examining expected dividend flows and market prices, the CAPM estimates required returns by evaluating the relative risk of alternative investments.

In comparison with the expected return on a risk-free investment, a risky investment must provide investors with a risk premium – an expected return higher than the riskless rate. The most commonly used measure of a risk-free asset is a short term (e.g., 90 day) U.S. Treasury security, which has little or no default or inflation price risk. It should be emphasized that only very short term Treasury debt can be assumed to be risk-free. Long term treasury debt, which locks investors into U.S. dollar denominated assets for years, can be very risky as inflation or international currency fluctuations can significantly impair investment value.

Investors who locked their investments into long term treasuries in 2000 have seen the purchasing value of their investment decline by about one-third in terms of buying power in relation to Canadian, European and other world currencies. Only very short term treasury debt is substantially free of this and the risk of inflation, which can also cause the real asset value of long term Treasury bonds to plummet as they did in the early 1980s.

CAPM separates the total risk of an investment into two parts: systematic and unsystematic risk. Systematic risk is unavoidable; it affects all assets to a greater or lesser degree. For example, a sharp rise in inflation would affect all stocks to a greater or lesser degree. The size of the risk premium for each stock is determined in proportion to the stock's co-movement with the market for all stocks. A stock that is twice as volatile as the average requires a risk premium that is double the average risk premium. A stock that is half as volatile as the average requires a risk premium that is half the average, etc. All systematic risk is rewarded with a risk premium, above the risk free rate of return that varies in direct proportion to the stock's relative volatility. The relative risk of each stock is measured by a value known as beta (B), which is a measure of the stock's relative volatility in comparison with the volatility of the entire market.

In contrast, unsystematic risk is that portion of total risk that can be avoided by diversifying. Unsystematic risk is not rewarded with a risk premium.

The CAPM defines the cost of equity for each company's stock as equaling the riskless rate plus an increment equal to the amount of systematic risk that goes with the investment:

$$K_n = R_f + B_n (R_m - R_f)$$

where,

K_n = the cost of equity for company n

R_f = the riskless rate of return

B_n = the beta for the stock of company n

$R_m - R_f$ = the expected market risk premium

(i.e., the average difference between the expected returns on the diversified market portfolio and the riskless return).

Q. WHAT ARE THE APPROPRIATE VALUES FOR THESE VARIABLES IN THIS CASE?

A. At the present time, riskless treasury bills are yielding less than 1 percent, and the high in recent years has been about 5 percent. Thus, R_f = 1.0 to 5.0 percent. With regard to risk premium, surveys and academic analyses indicate that the expected market risk premium R_m is in the range of 3 percent to 7 percent. For example, according to Dinson, March and Staunton ("Risks and Returns in the 20th and 21st Centuries," Business Strategy Review, 2000, Volume 11, Issue 2):

> "It has become clear that the current level of the equity risk premium is unlikely to be as high as was considered reasonable in the mid-1990s. The arithmetic mean of 8½% recommended by Ross, Westerfield and Jaffe (1993), the 8-9% suggested (with caveats) by Bealey and Myers (2000), and the 7½% recommended by Wetson, Chung and Sui (1997), and a similar figure inferred from the Copeland, Koller and Murrin (1995) geometric mean of 5-6%, all

> look excessive. The market is almost certainly building lower risk premia than this into stock prices….The cost of capital has thus fallen substantially in recent years."

Also, according to Eugene F. Fama of the University of Chicago and Kenneth R. French of the Massachusetts Institute of Technology, the risk premium over the past half-century was about 4 percent. Their calculation is based on going back to the past and analyzing what kinds of returns investors had a reasonable right to expect for the future, given companies' dividend yields and expected growth rates. Risk premiums exceeding 4 percent were, they say, the result of a series of surprises, such as the end of the Cold War and the development of the computer – windfalls that investors do not count on to repeat themselves. Fama and French expect stocks to outperform risk-free securities by only 3 percent to 3.5 percent a year in the long term. (See E.F. Fama and K.R. French, "Dividend Yields and Expected Stock Returns," Journal of Financial Economics, 22 (1), 3-25 and "Business Conditions and Expected Returns on Stocks and Bonds," Journal of Financial Economics, 25 (1), 23-49.)

Among the people who have studied the equity premium closely, most think it is probably in the range of 3 to 5 percentage points above treasury bills. On the other hand, rank-and-file finance professors have often continued to peg the long-term premium at about 6 to 7 percent, according to a comprehensive survey published by Ivo Welch of Yale University.

Welch, himself, agrees with the 3-5 percent range. According to his analysis, a 3 percent geometric equity premium estimate and a 5 percent arithmetic estimate are more accurate than the 6 percent to 7 percent consensus of the profession. (See Ivo Welch, "Views of Financial Economists on the Equity Premium and on Professional Controversies" (University of California, Los Angeles and Yale University, 2001)).

As shown in Exhibit___(JWW-7), average beta value for comparable gas distribution utilities is 0.657. Using 0.657 as the beta estimate and 5 percent as the market risk premium, the CAPM cost of equity estimate is:

$$K = 5.0\% + 0.657\ (5.0\%) = 8.285\%.$$

The result is lower if today's lower risk free rate is used in the calculation. CAPM equity return calculations are summarized in Exhibit___(JWW-5).

COMPARABLE EARNINGS

Q. HAVE YOU ALSO EXAMINED COMPARABLE EARNINGS FOR INVESTORS IN COMPARABLE UTILITIES?

A. Yes. I have examined the rates of return that are expected to be earned on common equity capital by comparable gas distribution utilities as well as returns that are expected to be earned in relation to the market prices of

those equity securities. This latter and most relevant comparison is essentially the return on book value divided by the market/book ratio.

Q. WHAT IS A MARKET/BOOK RATIO AND WHY IS IT RELEVANT IN DETERMINING A FAIR COMMON EQUITY RETURN ALLOWANCE?

A. A market/book ratio is the relationship that exists at any time between the market value that investors place on a firm's common stock and the stock's book value.

If regulators allow firms to earn rates of return that equal the cost of obtaining capital in the marketplace, then market forces will tend to drive the prices of stocks toward their book values. If the expected return exceeds the required return, the price of common stock will be greater than the stock's book value. If the expected return is lower than investor requirements, the market price will tend to fall below book value. If investor expectations and requirements are the same, the stock will tend to trade at a price equal to book value.

Q. IS THIS AN IMPORTANT CONSIDERATION IN RATE REGULATION?

A. Yes. It is an important consideration in rate regulation. If the market price of common stock rises to and remains at a level that is substantially in

excess of book value, that is a clear signal that investors' earnings expectations as a percentage of book value exceed the cost of capital, and that investors have capitalized these expected excess earnings by bidding up the price of common stock to a level greater than the stock's book value.

Thus, for example, if an investor purchases common shares at a market price equal to 1.5 times the stock's book value and the company earns a 15 percent rate of return on book value, the investor actually realizes a smaller return (i.e., 10 percent) on the market value of his or her investment. Since 15 percent exceeds the return that is required in the marketplace (we know that because, in this example, with a 15 percent return investors bid the stock price up to 150 percent of its book value), the 15 percent return on book value is capitalized (i.e., built into the discounted present value of the security) by investors, thus inflating the market price of stock. While this may result in gains for original stockholders who paid book value for their holdings, the excess return is an unnecessary expense for ratepayers if it is reflected in allowed rates. Since it is both excessive and unnecessary, this condition should typically be avoided under effective rate regulation. Of course, temporary fluctuations and short-term cycles affect prices, and a stock price varies from its trend over time. This means that if common equity costs remain about the same over time, and if investors expect future returns equal to the market cost of equity, the price of stock will fluctuate

within a reasonably narrow range of book value.

Q. IS THERE EVIDENCE AS TO WHAT RETURN ON EQUITY CAPITAL IS EXPECTED TO PRODUCE A MARKET-TO-BOOK RATIO OF 1.0 IN THE ELECTRIC UTILITY INDUSTRY IN THE FUTURE?

A. Yes. The Value Line Investment Survey, which is an excellent source of reported historical financial data, has published projected market-to-book ratios for comparable gas distribution utility companies for the period 2015-2017 in recent issues. These are summarized in Exhibit___(JWW-6). As shown in this Exhibit, it is projected that an average 11.74 percent return on the book value for comparable gas distribution utility companies will produce a market-to-book ratio of 1.79. This, in turn, implies a cost of equity capital for these companies of about 6.67 percent.

A market price equal to book value indicates that investors expect future earnings rates equal to their required return or cost of capital. To the extent that investors expect that the rate of return earned on book assets will exceed the required return or cost of capital, there will be a tendency to bid up the market value of stocks to the level at which the expected return in relation to market value equals the required return or cost of capital. Thus, if the required return or cost of capital is 8 percent, but investors expect that

a 12 percent return will be earned on book value, market prices will be bid up to 1.5 times book value so that the realized return equals the cost of capital (i.e., 8 percent). The implication in this case is that an equity return of 6.56 percent would be sufficient to sustain the stock price at book value, i.e.,

$$11.74/1.79 = 6.56.$$

Q. WHY HAVE YOU EXAMINED THESE EXPECTED COMPARABLE EARNINGS RATES?

A. Comparable rates of return from alternative investment opportunities determine the return level that investors can expect to obtain in competitive capital markets at any time. Moreover, comparable returns are generally considered by regulatory commissions and courts in determining "fair earnings" rates in rate proceedings. Indeed, regulatory standards demand that Commissions make an effort to allow similar profit rates to firms in similar circumstances. In examining comparable earnings data, it is, of course, important to remember that rates of return earned by other regulated companies are determined in some measure by previous regulatory decisions, and they may be either excessive or inadequate for certain firms at certain times. Therefore, while comparable earnings data do provide an essential reference point for any cost of capital decision (indeed,

comparable earnings opportunities are the foundation on which investors make their capital commitment determinations and they are therefore the foundation of DCF and other cost of capital models), a simple mathematical extrapolation is not always sufficient.

Q. SHOULD MDU'S RATES INCLUDE A COMMON EQUITY RATE OF RETURN ALLOWANCE EQUAL TO THAT EARNED IN RECENT YEARS BY THESE COMPARABLE COMPANIES?

A. Not necessarily. Experienced returns may be an approximate benchmark for return authorizations, but there are several reasons why caution should be exercised in simply applying those average rates of return here. First, there is an obvious element of circularity in allowing a rate of return for a given regulated enterprise equivalent to the rate of return which other regulated enterprises have been allowed to earn.

Second, earned returns are not always the same as required returns. When market-to-book ratios exceed unity, it means that book return expectations are higher than current equity market return requirements.

COMPARATIVE RISKS

Q. DR. GASKE HAS SUGGESTED THAT HIS PROPOSED ROE ALLOWANCE MAY BE WARRANTED BECAUSE MDU's GAS DISTRIBUTION UTILITY BUSINESS MAY BE PERCEIVED AS BEING EXCEPTIONALLY RISKY TO EQUITY INVESTORS BECAUSE IT IS COMPARATIVELY SMALL. IS THERE MERIT TO THAT CONTENTION?

A. No. It is incorrect to claim that the relatively small size of MDU's Montana gas utility operations in relation to Dr. Gaske's comparable gas utility companies implies greater investment risk for equity investors. While it is true that MDU's Montana gas distribution utility is smaller than Dr. Gaske's comparable companies, all of MDU's common equity capital is raised on a consolidated basis by the utility's parent, MDU Resources Group, Inc., which is considerably larger than most of Dr. Gaske's comparable gas distribution utility companies. In fact, MDU Resources' operating revenues are greater than the operating revenues of all but one of these companies, Atmos Energy, and Atmos, like MDU Resources, is comprised of smaller companies which, again like MDU, obtain their equity capital on a consolidated basis. All of Dr. Gaske's's comparable gas utilities, like MDU Resources, also have numerous smaller subdivisions or

subsidiaries that do business in various state jurisdictions. The individual jurisdictional utility operations of most of these companies are smaller parts of the larger companies of which they are part. All of MDU's Montana gas utility equity capital is obtained in financial markets by MDU Resources on a consolidated basis. MDU Resources, of which MDU's Montana gas utility operations are a part, is substantially larger than most of Dr. Gaske's comparable gas distribution utility companies and much larger than their individual jurisdictional utility operations. There is no evidence that MDU's cost of capital or its standing in capital markets is less favorable than these companies or that investment in its common equity is perceived as more risky.

Q. IS THERE EMPIRICAL EVIDENCE DEMONSTRATING THAT REGULATED GAS UTILITIES ARE LESS RISKY BUSINESSES THAN COMPETITIVE UNREGULATED ENTERPRISES?

A. Yes. Analyses of stock market indices reflect the comparatively stable and low-risk nature of common stock investments in regulated gas utilities.

Q. WHAT STOCK MARKET INDICES HAVE YOU REVIEWED?

A. In addition to the beta coefficients that I have used above in the CAPM cost of equity analyses, Value Line also publishes indices of safety, price stability and earnings predictability for a wide variety of firms in all sectors

of the economy. As shown in Exhibit___(JWW-7), the comparable gas utility companies have an average safety index of 1.75 on a scale from 1 to 5, where 1 is the highest safety rating. Also, price stability is ranked at 100 at the upper end of the scale from 5 to 100, where 100 is the highest stability rating. The average earnings predictability index for these companies is 80 on a scale from 5 to 100, and average "financial strength" is B++ to A. By all of these measures, the financial risks of these comparable gas utilities are indicated to be below average risk for publicly owned firms in the U.S. economy.

CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE DOES MDU RECOMMEND FOR RATEMAKING PURPOSES IN THIS CASE?

A. MDU recommends establishing a rate of return allowance based on what it refers to as its projected average utility capital structure for 2012, using beginning and end of year values (and average monthly short term debt) to compute the average. The result, as shown on page 1 of Rule 38.5.146, Statement F, is 53.387 percent common equity and 46.613 percent debt and preferred stock.

Q. IS THAT A REASONABLE CAPITAL STRUCTURE FOR

RATEMAKING PURPOSES IN THIS CASE?

A. A 53.387 percent common equity ratio is above the average common equity ratio of 49.74% for the comparable gas distribution utility companies as shown at page 9 of Exhibit No.__(JSG-2) Schedule 2. It is also above MDU's own target equity ratio of 50 percent as stated at pages 5 and 6 of the direct testimony of Company witness Senger. Note also that Mr. Senger refers to a 50/50 target "debt to equity" ratio rather than a target *common* equity ratio. Thus, the capital structure that MDU proposes for ratemaking purposes in this case (55.6% common and preferred equity and 44.4% debt) is not only equity-rich, but also well above the Company's stated target equity ratio.

Q. WHAT IS THE COST OF MAINTAINING A HIGH COMMON EQUITY RATIO?

A. The cost of maintaining a high common equity ratio is the resulting higher overall return requirement (including actual or imputed income tax costs) attributable to the higher percentage of common equity in the overall capital structure. This higher overall return requirement is attributable not only to the higher common equity return, but also to the fact that the equity return is loaded for additional income tax costs (as compared to debt, which has no income tax loading).

Q. IS THERE ANY BENEFIT TO MAINTAINING A HIGH COMMON EQUITY RATIO?

A. The benefit derived from maintaining a high common equity ratio is the savings in capital costs at the margin (if any), which are attributable to low debt leverage. To the extent that the costs of common equity, new debt and preferred stock are reduced as a consequence of a high common equity ratio, the annual savings are the benefits of maintaining high common equity ratios.

It may also be true that, when financial markets are especially risk-averse, companies with high common equity ratios may have greater access to new debt and equity capital. However, above the BBB bond rating category this advantage may not produce a net benefit to ratepayers as the cost of maintaining a thick equity ratio is not likely to exceed debt cost savings.

Q. DO THE BENEFITS OF HIGH COMMON EQUITY RATIOS GENERALLY OFFSET THE COSTS?

A. Not necessarily, and almost certainly, not above the level needed to attain a BBB+ to A bond rating. Although it is true that low common equity ratios imply greater financial risk and higher capital costs, the degree to which a high common equity ratio contributes to reductions in financial risk and capital costs, in comparison with an adequate common equity ratio, is most

likely to be minimal. The reason for this is that investors do not reduce their return requirements by enough as a result of the high common equity ratio to offset the higher cost of an equity-rich capital structure.

A second reason that the benefits to ratepayers do not generally offset the costs of high common equity ratios is that the additional costs of new debt and preferred stock issues (when ratings are lower and issue yields are incrementally higher) are generally small in comparison to the large additional overall pre-tax return requirement resulting from a higher common equity ratio. Very high common equity ratios are also not cost beneficial because the income tax allowance charged to ratepayers on the extra common equity capital would typically more than cancel out any cost savings that might be realized on new debt issues.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND FOR RATEMAKING PURPOSES IN THIS CASE?

A. I recommend a capital structure with no more than 50 percent common equity. Thus, I would recommend adjusting the Company's proposed capital structure and allowed rate of return on rate base as shown below.

RATE OF RETURN RECOMMENDATION

Q. WHAT IS YOUR SPECIFIC RATE OF RETURN RECOMMENDATION IN THIS CASE?

A. As I said at the outset, within a zone of reasonableness, the determination of an appropriate ROE allowance is a matter of the Commission exercising its discretion in balancing the public interest objectives of consumer protection and incentives for adequate service and capital attraction. As summarized in Exhibit___(JWW-8), the empirical evidence and calculations that I have provided define an ROE zone of reasonableness within a range from about 7 percent to 9 percent. Within this zone of reasonableness, I use the 9 percent to calculate a recommended return on rate base for MDU in this case. An ROE allowance of this amount acknowledges that MDU has provided and is expected to continue to provide adequate service to its Montana customers. It also recognizes MDU's comparatively modest level of business risk for its gas distribution utility business. Based on a 9 percent ROE allowance and the capital structure below, the Company's allowed return on its gas distribution utility rate base would be 7.615 percent:

	Ratio	Cost	Allowed Return
Long Term Debt	43.078%	6.846%	2.949%
Short Term Debt	4.750%	1.399%	0.066%

Preferred Stock	2.172%	4.583%	0.100%
Common Equity	50.00%	9.000%	4.500%
	Overall Return		7.615%

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes; it does.

DCF Cost of Equity Indications

Earnings Growth Model

Comparable Gas Distribution Companies

		(1)	(2)	(3)	(4)
		Recent Dividend	Projected Growth		D/P + g
	Company	Yield	Value Line	Zacks	
GAS	AGL Resources Inc.	4.8%	6.0%	4.4%	10.0%
ATO	Atmos Energy Corp.	4.1%	4.0%	6.0%	9.1%
LG	Laclede Group, Inc.	4.3%	3.0%	3.0%	7.3%
NJR	New Jersey Resources Corp.	4.0%	5.5%	4.0%	8.8%
NWN	Northwest Natural Gas Co.	4.2%	3.0%	4.2%	7.8%
PNY	Piedmont Natural Gas Co., In	4.0%	2.5%	3.7%	7.1%
SJI	South Jersey Industries, Inc.	3.6%	9.0%	6.0%	11.1%
SWX	Southwest Gas Corp.	3.1%	9.0%	5.0%	10.1%
	Average				**8.91%**
	Median				**8.93%**

Sources: Value Line Investment Survey December 7, 2012.
Zacks Investment Research, February 5, 2013 (http://www.zacks.com).

DCF Cost of Equity Indications

Dividend Growth Model

Comparable Gas Distribution Companies

	Company	(1) Recent Dividend Yield	(2) Projected Dividends Growth	(3) D/P + g
GAS	AGL Resources Inc.	4.8%	1.5%	6.3%
ATO	Atmos Energy Corp.	4.1%	1.5%	5.6%
LG	Laclede Group, Inc.	4.3%	2.5%	6.8%
NJR	New Jersey Resources Corp.	4.0%	4.0%	8.0%
NWN	Northwest Natural Gas Co.	4.2%	2.5%	6.7%
PNY	Piedmont Natural Gas Co., In	4.0%	3.5%	7.5%
SJI	South Jersey Industries, Inc.	3.6%	9.0%	12.6%
SWX	Southwest Gas Corp.	3.1%	8.0%	11.1%
	Average			**8.08%**
	Median			**7.15%**

Sources: Value Line Investment Survey December 7, 2012

DCF Cost of Equity Indications

Book Value Growth Model

Comparable Gas Distribution Companies

	Company	(1) Recent Dividend Yield	(2) Projected Book Value Growth	(3) D/P + g
GAS	AGL Resources Inc.	4.8%	5.0%	9.8%
ATO	Atmos Energy Corp.	4.1%	6.0%	10.1%
LG	Laclede Group, Inc.	4.3%	4.5%	8.8%
NJR	New Jersey Resources Corp.	4.0%	5.5%	9.5%
NWN	Northwest Natural Gas Co.	4.2%	1.0%	5.2%
PNY	Piedmont Natural Gas Co., In	4.0%	1.5%	5.5%
SJI	South Jersey Industries, Inc.	3.6%	6.0%	9.6%
SWX	Southwest Gas Corp.	3.1%	6.0%	9.1%
	Average			**8.45%**
	Median			**9.30%**

Sources: Value Line Investment Survey December 7, 2012

DCF Cost of Equity Indications

Fundamental Growth Model

Comparable Gas Distribution Companies

	Company	(1) Projected D/P	(2) Fundamental Growth	(3) D/P + g
GAS	AGL Resources Inc.	3.5%	6.5%	10.0%
ATO	Atmos Energy Corp.	4.2%	3.5%	7.7%
LG	Laclede Group, Inc.	3.8%	4.5%	8.3%
NJR	New Jersey Resources Corp.	3.5%	7.5%	11.0%
NWN	Northwest Natural Gas Co.	3.3%	4.0%	7.3%
PNY	Piedmont Natural Gas Co., In	3.9%	3.5%	7.4%
SJI	South Jersey Industries, Inc.	3.7%	7.5%	11.2%
SWX	Southwest Gas Corp.	2.8%	6.0%	8.8%
	Average			**8.96%**
	Median			**8.55%**

Sources: Value Line Investment Survey December 7, 2012

Capital Asset Pricing Model

Cost of Equity Capital: $k = R_f + \beta (R_m - R_f)$

Risk-free Yield (R_f)	1% to 5%
Beta Coefficient (β)	0.656
Equity Risk Premium ($R_m - R_f$)	3% to 7%
Estimated Cost of Equity Capital (k)	2.97% - 9.59%
Mid Point of Range	6.28%

Comparable Expected Market Earnings Rates

Comparable Gas Distribution Companies

	Company	(1) Projected Book Return	(2) Projected Market/Book	(3) Expected Market Earnings Rate
GAS	AGL Resources Inc.	11.41%	1.71	6.67%
ATO	Atmos Energy Corp.	7.79%	1.01	7.69%
LG	Laclede Group, Inc.	10.00%	1.55	6.45%
NJR	New Jersey Resources Corp.	14.05%	1.97	7.14%
NWN	Northwest Natural Gas Co.	11.35%	1.93	5.88%
PNY	Piedmont Natural Gas Co., Inc.	12.67%	2.28	5.56%
SJI	South Jersey Industries, Inc.	16.19%	2.27	7.14%
SWX	Southwest Gas Corp.	10.42%	1.56	6.67%
	Average	**11.73%**	**1.79**	**6.65%**
	Median	**11.38%**	**1.82**	**6.67%**

Sources: Value Line Investment Survey December 7, 2012

Comparative Risk Indicators

Comparable Gas Distribution Companies

	Company	(1) Beta	(2) Safety	(3) Price Stability	(4) Earnings Predictability	(5) Financial Strenght
GAS	AGL Resources Inc.	0.75	1	100	75	A
ATO	Atmos Energy Corp.	0.70	2	100	90	B++
LG	Laclede Group, Inc.	0.55	2	100	80	B++
NJR	New Jersey Resources Corp.	0.65	1	100	50	A
NWN	Northwest Natural Gas Co.	0.55	1	100	90	A
PNY	Piedmont Natural Gas Co., In	0.65	2	100	95	B++
SJI	South Jersey Industries, Inc.	0.65	2	100	85	B++
SWX	Southwest Gas Corp.	0.75	3	100	75	B
	Average	**0.656**	**1.75**	**100.00**	**80.00**	**B++**

Sources: Value Line Investment Survey December 7, 2012

Summary

Cost of Common Equity Return Indicators

DCF Evidence (Average)	
Earnings Growth	8.91%
Dividends Growth	8.08%
Book Value Growth	8.45%
Fundamental DCF	8.96%
CAPM Evidence	6.28%
Comparable Expected Market Earnings	6.65%
Average of Above Measures	7.89%
Indicated Range of Reasonableness	7% - 9%

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

*** * * * ***

In the Matter of the Application of	**)**	**REGULATORY DIVISION**
MONTANA-DAKOTA UTILITIES CO.	**)**	
A Division of MDU Resources Group,	**)**	**DOCKET NO. D2012.9.100**
Inc., for Authority to Establish Increased	**)**	
Rates for Natural Gas Service	**)**	

Direct Testimony

of

Jacob Pous

On behalf of

Montana Consumer Counsel

Diversified Utility Consultants, Inc.

1912 West Anderson Lane, Suite 202

Austin, TX 78757

February 25, 2013

DIRECT TESTIMONY AND EXHIBITS OF JACOB POUS

ACRONYMS

2008 STUDY	Depreciation Studies, dated December 31, 2008
AICPA	American Institute of Certified Public Accountants
ALG	Average Life Group
ASL	Average Service Life
CFR	Code of Federal Regulations
CI	Conformance Index
COMMISSION	Montana Public Service Commission
CPI	Consumer Price Index
DUCI	Diversified Utility Consultants, Inc.
ELG	Equal Life Group
FERC	Federal Energy Regulatory Commission
MCC	Montana Consumer Counsel
MDU or COMPANY	Montana-Dakota Utilities Company
REI	Retirement Experience Index
SPR	Simulated Plant Records
USOA	Uniform System of Accounts

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DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

*** * * * ***

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., A Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Natural Gas Service	**)**	**REGULATORY DIVISION**
		DOCKET NO. D2010.9.100

SECTION I: INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jacob Pous and my business address is 1912 W Anderson Lane, Suite 202, Austin, Texas 78757.

Q. WHAT IS YOUR OCCUPATION?

A. I am a principal in the firm of Diversified Utility Consultants, Inc. ("DUCI"). A copy of my qualifications appears as Appendix A.

Q. PLEASE DESCRIBE DIVERSIFIED UTILITY CONSULTANTS, INC.

A. DUCI is a consulting firm located in Austin, Texas with an international client base. The personnel of DUCI provide engineering, accounting, economic, and financial services to its clients. DUCI provides utility consulting services to municipal governments with utility systems, to end-users of utility services, and to regulatory bodies such as state public service commissions. DUCI provides complete rate case analyses, expert testimony, negotiation services, and litigation support to clients in electric, gas, telephone, water, sewer, and cable utility matters.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN PUBLIC UTILITY PROCEEDINGS?

A. Yes. Appendix A also includes a list of proceedings in which I have previously presented testimony. In addition, I have been involved in numerous utility rate proceedings that resulted in settlements before testimony was filed. In total, I have participated in well over 400 utility rate proceedings in the United States and Canada. Also worthy of note is that I have testified on behalf of the staff of five different state regulatory commissions and one Canadian regulatory commission.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I am a registered professional engineer. I am registered to practice as a Professional Engineer in the State of Texas, as well as numerous other states.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. I am testifying on behalf of the Montana Consumer Counsel (MCC).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been requested to review Montana-Dakota Utilities Company's (MDU or Company) depreciation request, and to the extent I identify concerns or problems to address such concerns and problems with an alternative recommendation.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company retained AUS Consultants to perform depreciation analyses for both its Gas and Common plant divisions. Mr. Robinson of AUS Consultants developed two depreciation studies (2008 Study). The first study is for the Gas division and identified as Exhibit No._(EMR-1) while the second study is for the Common plant and is presented as Exhibit No._(EMR-2). After review of the Company's studies, workpapers, and responses to discovery, I conclude that the

results of the studies are significantly flawed and yield excessive levels of depreciation expense. A brief summary of the issues I address follows.

Gas Plant

- **Life** – While it appears the Company has some level of age retirement data, it has selected the Simulated Plant Records (SPR) semi-actuarial analysis approach for life analysis investigation. Unfortunately, the Company failed to retain the underlying results of the SPR statistical analyses. Based on the available information, an adjustment to MDU's proposal for its largest plant account, Account 376 – Distribution Mains, is warranted. The Company's proposed 47-year average service life (ASL) with a R4 Iowa Survivor curve significantly understates the reasonable expected life for the investment in this account. My recommended 60R2.5 life-curve combination reflects a more realistic life expectation and results in a $1,043,790 reduction in total Company annual depreciation expense based on plant as of December 31, 2008.

- **Net Salvage** – The Company fails to support or explain its various proposals. In addition, the Company employs an unusual quantitative analysis that assumes inflation is the sole driving factor of future net salvage expectations. Review of the available data and correction of the inappropriate reliance on inflation results in the need to modify Mr. Robinson's proposal for the three largest accounts. The three largest accounts represent the vast majority of depreciation expense at issue. Adoption of more realistic negative net salvage values for the three accounts results in a $1,496,989 reduction to total Company depreciation expense based on plant as of December 31, 2008.

- **Combined Impact** – The combined impact of the various life and salvage adjustments are not simply the summation of the individual standalone impacts when both life and net salvage adjustments are proposed for the same account.

The combined impact of my recommendations for Gas plant depreciation expense is a total Company reduction of $2,279,808 for plant as of December 31, 2008 and is set forth on Exhibit (JP-1) page 1.

Common Plant

- **Life** – Account 390 – Structures & Improvements represents the majority of the investment at issue in Common plant. Mr. Robinson performed an actuarial analysis on the data and appears to rely on his interpretation of the results of such analyses for his proposal of a 35-year ASL. Upon review of the Company's investment in this account, which is overwhelmingly associated with steel office buildings, a much longer ASL is warranted. Adoption of a 55-year ASL results in a $263,866 reduction to total Company depreciation expense based on plant as of December 31, 2008.

- **Net Salvage** – Without support or explanation, Mr. Robinson proposes a zero (0)% net salvage for retirement of steel office buildings after a 35-year ASL. Review of historical data, Mr. Robinson's unusual future forecasting analysis, as well as the actual retirement of 11 buildings by the Company during the last 20 years clearly demonstrates that a zero (0) level of net salvage for the investment in this account is woefully inadequate. Adoption of an initial step to a positive 20% net salvage in this proceeding results in a $283,205 reduction in total Company depreciation expense based on plant as of December 31, 2008.

- **Combined Impact** – The combined impact of the various life and salvage adjustments are not simply the summation of the individual standalone impacts when both life and net salvage adjustments are proposed for the same account. The combined impact of my recommendations for Common plant depreciation expense is a total Company reduction of $383,630 and is set forth on Exhibit (JP-1) page 2.

Q. IS THERE AN AREA OF CONCERN THAT NEEDS TO BE DISCUSSED PRIOR TO THE REMAINING PORTION OF YOUR TESTIMONY?

A. Yes. Having been involved in over 400 rate proceedings including hundreds of analyses of depreciation requests, the presentation by the Company in support of its proposals stands out and raises significant concerns. Overall, the Company's support and justification for its various proposals at best can be characterized as vague and meager. Mr. Robinson provides only very limited and general comments as to any steps undertaken and how any information obtained from historical analyses is combined with any other item of information to produce his ultimate proposal.

However, what makes this particular situation even more untenable is the fact that Mr. Robinson elected to destroy or not retain critical workpapers he developed as part of his life analysis for Gas plant depreciation. In performing SPR life analysis, the standard output yields the best-fitting ASL for 29 different Iowa Survivor curves for each different historical band of data analyzed. While Mr. Robinson claims he performed such analyses, he further states that the "output of SPR analysis is not maintained in paper copy or other format."[1] Mr. Robinson's decision to destroy or not maintain such workpapers was made with the full knowledge that the SPR "method was the <u>primary</u> input for estimating the average service life parameters."[2] (Emphasis added). In other words, he destroyed the underlying workpapers that formed the statistical and primary basis for his proposals. Such actions in a depreciation study are not standard by any means. Moreover, Mr. Robinson's results cannot be duplicated given his vague presentation of analysis he performed.

[1] Response to MCC-150.
[2] Response to MCC-177.

No matter what the outcome of this proceeding, I recommend that the Montana Public Service Commission (Commission) order the Company to actually document how it specifically arrived at each of its life and net salvage proposals and provide such information in its next depreciation study. The documentation should include all analyses and items of information obtained in the overall process in order to permit a more reasonable vetting of what the Company actually performed and how it arrived at its proposals. Such information is critical given the limited time and access to Company personnel and records available to intervenors in rate proceedings.

SECTION II: DEPRECIATION

Q. WHAT IS DEPRECIATION?

A. There are two commonly-cited definitions of depreciation. The first comes from the Federal Energy Regulatory Commission (FERC):[3]

> 'Depreciation,' as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

The second definition, from the American Institute of Certified Public Accountants (AICPA), is similar:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may

[3] Title 18 of the Code of Federal Regulations (CFR) Part 201, Definition 12.

be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is a portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

Q. WHAT ARE THE TWO GENERAL FORMULAS USED IN DETERMINING DEPRECIATION RATES?

A. The whole life and the remaining life technique are the most commonly used formulas. The whole life technique is as follows:[4]

$$\text{Depreciation Rate (\%)} = \left[\frac{\dfrac{(\text{Original Cost} - \text{Net Salvage})}{\text{Average Service Life}}}{\text{Original Cost}}\right]$$

The remaining life technique is as follows:

$$\text{Depreciation Rate (\%)} = \left[\frac{\dfrac{\text{Original Cost} - \text{Accumulated Provision For Depreciation} - \text{Net Salvage}}{\text{Remaining Service Life}}}{\text{Original Cost}}\right]$$

The two formulas should equal each other when the difference between the theoretical reserve and the actual Accumulated Provision for Depreciation is recovered over the remaining life of the investment under the whole life technique.

Q. ARE THERE ADDITIONAL CONSIDERATIONS IN DEPRECIATION BEYOND THE DEFINITIONS?

A. Yes. The definitions provide only a general outline of the overall utility depreciation concept. In order to arrive at a depreciation-related revenue requirement in a rate proceeding, a depreciation system must be established.

[4] A theoretical depreciation reserve calculation is developed and compared to the actual accumulated provision for depreciation in conjunction with the whole life technique. If the differential is significant, an amortization of the differential for some period of time may be recommended.

Q. WHAT IS A DEPRECIATION SYSTEM?

A. A depreciation system constitutes the method, procedure, and technique employed in the development of depreciation rates.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY "METHOD."

A. "Method" identifies whether a straight-line, liberalized, compound interest, or other type of calculation is being performed. The straight-line method is normally employed for utility depreciation proceedings.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY "PROCEDURE."

A. "Procedure" identifies a calculation approach or grouping. For example, procedures can reflect the grouping of only a single item, items by vintage (year of addition), items by broad group or total grouping, or equal life groupings (ELG). The average life group (ALG) procedure is used by the vast majority of utilities. Both Mr. Robinson and I have utilized the ALG procedure in this case.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY "TECHNIQUE."

A. There are two main categories of techniques with various sub-groupings: the whole life technique and the remaining life technique. The whole life technique simply reflects calculation of a depreciation rate based on the whole life (*e.g.*, a 10-year life would imply a 10% depreciation rate over the life of the plant). The remaining life technique recognizes that depreciation is a forecast or estimation process that is never precisely accurate and that requires true-ups in order to recover exactly 100% of what a utility is entitled to over the entire life of the investment. Therefore, as time passes, the remaining life technique attempts to recover the remaining unrecovered balance over the remaining life or other period of time. Most utilities rely on a remaining life technique in utility rate matters. Both the Company and I have utilized the remaining life technique.

Q. DO THE METHODS, PROCEDURES, AND TECHNIQUES INTERACT WITH ONE ANOTHER?

A. Yes. Different depreciation rates will result depending on what combination of method, procedure, and technique is employed. Differences will occur even when beginning with the same ASL and net salvage values.

Q. WHAT IS NET SALVAGE?

A. Net salvage is the value obtained from retired property (the gross salvage) less the cost of removal. Net salvage can be either positive, in cases where gross salvage exceeds cost of removal, or negative, in cases where cost of removal is greater than gross salvage.

Q. HOW DOES NET SALVAGE IMPACT THE CALCULATION OF DEPRECIATION?

A. The intent of the depreciation process is to allow the Company to recover 100% of investment less net salvage. Therefore, if net salvage is a positive 10%, then the utility should only recover 90% of its investment through annual depreciation charges, under the theory that it will recover the remaining 10% through net salvage at the time the asset retires (90% + 10% = 100%). Alternatively, if net salvage is a negative 10%, then the utility should be allowed to recover 110% of its investment through annual depreciation charges so that the negative 10% net salvage that is expected to occur at the end of the property's life will still leave the utility whole (110% - 10% = 100%).

SECTION III: LIFE ANALYSIS

A. General

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony will address the Company's proposed life-curve combinations represented by an ASL and a corresponding Iowa Survivor curve. In order to develop a depreciation rate for each account, a remaining life based on a specific life-curve combination must be developed.

Q. HOW ARE LIFE-CURVE COMBINATIONS NORMALLY DEVELOPED FOR UTILITY PROPERTY?

A. Normally, for mass property accounts such as those at issue in this particular case, statistical life analyses are performed either on an actuarial or semi-actuarial basis. Actuarial analyses are performed when aged data is available.[5] Alternatively, when only unaged data is available, semi-actuarial analyses utilizing the SPR method are normally relied upon. In this case, the Company performed SPR analyses for Gas plant and actuarial analyses for Common plant.

[5] Aged data represents a situation where a utility maintains the installation year corresponding to each item of plant so that the age can be obtained when the item retires.

Q. DOES MR. ROBINSON PRESENT GENERAL INFORMATION REGARDING ACTUARIAL, SEMI-ACTUARIAL, AND IOWA SURVIVOR CURVES IN HIS TESTIMONY AND 2008 STUDY?

A. Yes. Since Mr. Robinson has already presented a generalized explanation of these items I will not repeat or expand upon such explanations in my testimony.

Q. IS THERE ANY NEED TO INVESTIGATE THE MANNER IN WHICH MR. ROBINSON EMPLOYED ACTUARIAL ANALYSIS?

A. No. The only adjustment I recommend in this proceeding associated with Mr. Robinson's actuarial analyses is to Common plant Account 390 – General Plant Structures & Improvements. However, my recommended adjustment for this account does not relate to actuarial analyses. In addition, while Mr. Robinson did not perform actuarial analyses for Distribution mains, I did perform an actuarial analysis on limited age data provided by the Company.

Q. PLEASE DISCUSS THE SPR ANALYSIS IN THIS PROCEEDING.

A. For Gas plant, Mr. Robinson relied on the SPR method. This method simulates plant balances over time and compares the simulated results to actual plant balances for each of 29 different Iowa Survivor curves. The best-fitting curves results from a sum of squared difference calculation standpoint are ranked, and a Retirement Experience Index (REI) is produced as part of the SPR analyses.[6] In this particular situation, Mr. Robinson chose to destroy or not retain the output of each of his various unidentified SPR analyses for each account.

[6] Retirement Experience Index simply represents the statistical stability of the results based upon the completeness of the Iowa Survivor curve and must be considered in conjunction with sum of squared difference statistics.

Q. WHY DID MR. ROBINSON NOT RETAIN CRITICAL WORKPAPERS?

A. The reasoning for his actions is unknown, but unacceptable. Other depreciation analysts do specifically provide such information, quite often even in their direct filing, but otherwise in response to discovery. Unfortunately, Mr. Robinson did not and cannot provide such information.

Q. ARE THE RESULTS OF STATISTICAL ANALYSES THE ONLY CONSIDERATION IN ESTABLISHING LIFE EXPECTATIONS FOR UTILITY PROPERTY?

A. No. Other factors such as understanding of the type of investment currently in place versus the type of investment reflected in historical retirements, changes in technology, changes in Company policy, and other factors can have an impact in certain instances. However, it must be noted that Mr. Robinson admits that the SPR analysis was the "primary input" for the ASL proposals.[7]

Q. DID MR. ROBINSON PROVIDE ANY SPECIFICS ASSOCIATED WITH ANY OTHER FACTORS FOR ANY OF HIS LIFE ANALYSIS PROPOSALS?

A. No. Mr. Robinson chose to reference "other factors," but only in the most general sense. None of Mr. Robinson's general or vague references support any given ASL or related Iowa Survivor curve selection.

Q. GIVEN THE LACK OF SUPPORT PRESENTED BY MR. ROBINSON, HOW WERE YOU ABLE TO PERFORM YOUR ANALYSES?

A. For Gas plant, the investment and corresponding depreciation expenses at issue are highly concentrated in three accounts. In fact, Account 376 – Distribution Mains, Account 380 – Distribution Services, and Account 381 – Distribution Meters

[7] Response to MCC-177.

reflect approximately 84% and 90% of the investment and depreciation expense at issue, respectively.[8] For these three accounts. Mr. Robinson's ASL proposal for Account 376 – Distribution Mains on its face appears to be low. The reason Mr. Robinson's proposal stood out on its face is that the industry discussion now generally centers on values for Distribution mains between the upper 50-year range to the mid 70-year range. In comparison, Mr. Robinson proposes a 47-year ASL. Absent a strong showing associated with situations that may reflect problematic pipe that must be replaced early, a 47-year ASL requires substantial justification before acceptance. As previously discussed, Mr. Robinson provides no meaningful justification for any of his proposals. Due to Mr. Robinson's significantly short ASL proposal for this account, I focused my efforts there.

B. Gas Plant Life Analysis

Q. WHAT IS THE ISSUE YOU ADDRESS IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony will address the Company's unsupported proposal for a 47-year ASL for Account 376 – Distribution Mains. This single account represents 47% of the Company's investment in Distribution plant as of the depreciation study period.

Q. FROM A HIGH LEVEL PERSPECTIVE, WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSED 47-YEAR ASL?

A. Mr. Robinson states that the "proposed average service life for each subproperty group [in Account 376 – Mains] was changed in accordance with the life indication developed through an analysis of the Company's historical data and

[8] 2008 Study Exhibit No._(EMR-1) page 2-1.

consideration of future expectations."[9] Elsewhere in the 2008 Study, Mr. Robinson states that he also held discussions with MDU management to obtain an overview of the Company's facilities and to discuss the general scope of operations together with other factors, which "could" have a bearing on the service life of the property.[10] In other words, from a high level, Mr. Robinson states that he analyzed historical data using the SPR statistical technique and held discussions with Company management in order to obtain information that "could" have a meaningful bearing on the overall life expectancy of plant at issue. However, as previously noted, the "primary input" for Mr. Robinson's proposed 47-year ASL was his SPR analyses, which he elected to destroy or not retain.

Q. PLEASE DISCUSS MR. ROBINSON'S ANALYSIS OF HISTORICAL DATA.

A. While Mr. Robinson claims he performed SPR analyses, he cannot produce the underlying workpapers. In the only two instances where Mr. Robinson professes to have captured and retained some SPR results, the SPR results presented in no way compared to the ASLs he proposes.[11] In other words, to the extent one accepts Mr. Robinson's claim that he performed numerous SPR analyses for each account, the only actual, but very limited, information he provided in response to discovery indicates dramatically longer ASLs compared to his proposal.

[9] 2008 Study Exhibit No._(EMR-1) at page 1-5.
[10] 2008 Study Exhibit No._(EMR-1) at pages 3-1 and 3-2.
[11] Responses to MCC-150 and 151.

Q. DO YOU HAVE CONCERNS REGARDING MR. ROBINSON'S CLAIM THAT HE PERFORMED NUMEROUS SPR ANALYSES FOR THE VARIOUS GAS PLANT ACCOUNTS?

A. Yes. Having been involved in hundreds of depreciation proceedings, I do not recall ever encountering a situation where the depreciation witness either did not provide the standard output for SPR analyses as part of the depreciation study, or provided such information in discovery. Unfortunately, Mr. Robinson claims that he destroyed the results of each of the claimed SPR analyses performed when he elected not to retain the analyses either in paper copy or other format.[12]

Q. IF MR. ROBINSON DID NOT KEEP HARD COPIES OR ELECTRONIC FILES ASSOCIATED WITH THE OUTPUT OF THE VARIOUS CLAIMED SPR ANALYSIS, HOW IS HE ABLE TO PRODUCE THE ONE-PAGE LIMITED SUMMARY OF CERTAIN SPR ANALYSES IN RESPONSE TO DISCOVERY?

A. That is a very good question. The two positions are inconsistent. In other words, one cannot destroy or fail to retain the SPR results, but then produce a very limited and incomplete listing of certain results. Either: (1) the results exist and Mr. Robinson does not want to provide them as they may not support his proposals, or (2) the results did not exist, but Mr. Robinson chose to recreate a limited portion of them for discovery purposes. In either instance, Mr. Robinson's claimed reliance on SPR results are totally unsupported with detailed output of SPR programs, or to the extent the limited reproduced information is all that exists, then Mr. Robinson has woefully understated the expected ASL based on historical analyses.

[12] Responses to MCC-150 and 151.

Q. WHAT DID MR. ROBINSON SPECIFICALLY PRODUCE AS AN INDICATION OF SPR RESULTS FOR ACCOUNT 376 – DISTRIBUTION MAINS?

A. In response to MCC-150, Mr. Robinson produced a one-page summary of simulated curve-fitting results, claiming that it is based on a five-year band. That document is set forth as Exhibit (JP-2). Review of Exhibit (JP-2) indicates that the most relevant information is not associated with a five-year band, but rather a full experience band reflecting data from 1916 through 2008. Next, assuming the best-fitting curve is presented for each of the limited band analyses performed, it is clear that Mr. Robinson could not identify a single analysis based on the last 35 years of experience that yielded a best-fitting life-curve combination with less than a 61-year ASL. This compares to Mr. Robinson's proposed 47-year ASL. The only available conclusion is that the shortest ASL indicated by SPR analysis is 30% greater than Mr. Robinson's proposed ASL.[13]

Q. WHY DID MR. ROBINSON PRESENT FIVE-YEAR INCREMENTS IN EXPERIENCE BANDS AS SET FORTH ON EXHIBIT (JP-2)?

A. Mr. Robinson states in his 2008 Study that "various test bands are reviewed to determine trends or changes to indicated service lives in the various bands of years."[14]

[13] (61.2 years – 47 years) / 47 years = 30.2%.
[14] 2008 Study Exhibit No._(EMR-1) at page 3-19.

Q. TO THE EXTENT A TREND EXISTS IN THE DATA FOR ACCOUNT 376 BASED ON SPR RESULTS, DO THEY INDICATE A LENGTHENING OR SHORTENING OF LIFE?

A. To the extent any of the information contained in Exhibit (JP-2) can be considered appropriate, the information indicates a significant lengthening of life expectancy for investment in Distribution mains over time.

Q. PLEASE EXPLAIN YOUR PRIOR STATEMENT THAT MR. ROBINSON'S SPR PRESENTATION SET FORTH ON EXHIBIT (JP-2) IS LIMITED AND INCOMPLETE AT BEST.

A. The typical type of results obtained from SPR analyses are set forth on Exhibit (JP-3). Exhibit (JP-3) represents a typical printout presented by another utility in another current proceeding.

Review of Exhibit (JP-3) identifies that SPR results for any given band analysis normally yields the best-fitting ASL for 29 different Iowa Survivor curves. Iowa Survivor curves are standardized curves utilized throughout the industry in determining and presenting depreciation parameters for utility rate matters. In addition, the typical printout produces a Conformance Index (CI) and a REI for each of the 29 different Iowa Survivor curves tested. The CI and REI are statistical measures of goodness of fit or completeness of the simulated Iowa Survivor curve. There are industry accepted ranking criteria for CIs and REIs that provide guidance in the selection of the best-fitting life-curve combination based on proper interpretation of the information, not necessarily the top-listed curve.

Q. HOW DOES MR. ROBINSON'S PRESENTATION DIFFER FROM THE INDUSTRY STANDARD PRESENTATION?

A. Obviously, Mr. Robinson's presentation identifies the results for only a single Iowa Survivor curve and not for the remaining 28 Iowa Survivor curves for each band analysis. Moreover, it would be unusual to perform a full-band analysis and a five-year experience band analysis with no intermittent band analyses. In other words, to the extent Mr. Robinson actually performed SPR analyses, the results undoubtedly were of a much more expansive nature than presented in his one-page limited summary. Therefore, no credence can be given to Mr. Robinson's claim that his proposal is based on a detailed analysis of historical data.

Q. DID YOU SPECIFICALLY SEEK THE RANKING CRITERIA RELIED UPON BY MR. ROBINSON TO THE EXTENT HE ACTUALLY PERFORMED SPR ANALYSES?

A. Yes. Unfortunately, Mr. Robinson chose to remain silent in his response to that particular request.[15]

Q. DID MR. ROBINSON PROVIDE THE UNDERLYING DATABASE THAT WOULD PERMIT REPLICATION OF HIS SPR ANALYSES?

A. No, not initially. While Mr. Robinson claims he provided the claimed database, he initially failed to identify what is specifically contained in the tens of thousands of values provided. In particular, there are "codes" associated with each line item but there was no explanation of what the code represents.[16] Moreover, since Mr. Robinson did not identify the specific experience band, placement band, and intervals or test points for each account, there is no way that anyone could know which combination of values to analyze in order to attempt to duplicate results that

[15] Responses to MCC-150 and 151.
[16] Response to MCC-135.

Mr. Robinson apparently chose to destroy or not retain. In other words, Mr. Robinson's offer to provide the input data in a less than meaningful manner only ensured that no one could duplicate his unknown analyses.

Q. THEN FROM AN ANALYSIS OF HISTORICAL DATA STANDPOINT WHICH MR. ROBINSON ADMITS IS THE "PRIMARY" BASIS FOR ESTABLISHING A PROPOSED ASL, HE CANNOT PRODUCE ANYTHING THAT WOULD SUPPORT HIS CLAIM, CORRECT?

A. That is correct.

Q. DID MR. ROBINSON PROVIDE A GRAPHICAL PRESENTATION OF THE CLOSENESS OF FIT BETWEEN HIS PROPOSAL AND THE ACTUAL BALANCE OVER TIME?

A. Yes. In Section 5 of his Gas plant 2008 Study, he produced what he claims to be a graphical representation over time of the simulated plant balance associated with his proposed life-curve combination and the actual plant balances for those years.

Q. IS THAT PRESENTATION BY MR. ROBINSON COMPLETE AND MEANINGFUL?

A. No. The graphical presentation fails to demonstrate whether other life-curve combinations were superior or more representative of the data. Indeed, when Mr. Robinson performed actuarial analysis for the Company's Common plant, he not only provided the graphical comparison, but he also provided the underlying numerical values as set forth in Exhibit No._(EMR-2) Section 5. In other words, Mr. Robinson's presentation for SPR analyses is inconsistent with the level of support set forth when he performs actuarial analysis as he did for the Company's Common plant. For his Common plant life analysis, Mr. Robinson recognized the need to retain workpapers, both in paper copy and apparently in electronic format,

a practice he failed to perform for SPR analyses performed for the Company's Gas plant.

Q. TURNING TO THE OTHER ASPECT OF LIFE ESTIMATION, THAT BEING THE OTHER FACTORS MR. ROBINSON ALLUDED TO IN HIS TESTIMONY, WHAT DID MR. ROBINSON ACTUALLY PRESENT IN SUPPORT OF HIS POSITION?

A. Unfortunately, Mr. Robinson's presentation for the "other factors" is no better than his presentation of SPR results. Apparently, Mr. Robinson believes his proposals are adequately supported by simply stating the final life parameter and that the parameter is based on undocumented generalized concepts. Indeed, the greatest level of definition to the other factors is set forth in Section 4 of his Gas plant 2008 Study, which in reality provides no specificity in support of his proposals.

Q. WHAT DOES MR. ROBINSON CLAIM FOR THE LARGEST PLANT ACCOUNT, ACCOUNT 376 – DISTRIBUTION MAINS?

A. For Account 376.1 – Distribution Mains – Steel, Mr. Robinson identifies that a portion of the property is associated with bare steel while the Company now continues to install coated and wrapped steel mains for higher pressure and larger size requirements.[17] However, these items of information in no way define a specific life; rather they only give insight as to why there is a trend in the data towards a longer life.

Indeed, many utilities across the country, including those analyzed by Mr. Robinson, have implemented bare steel replacement programs where bare steel investment is being removed at ages earlier than they would have obtained absent such programs. While these programs shorten the overall expected life of

[17] 2008 Study Exhibit No._ (EMR-1) page 4-4.

historical steel mains, they are not indicative of the replacement mains associated with coated and wrapped steel. Indeed, as better technology has been developed for coated and wrapped steel, longer life expectations have become the industry standard. Yet Mr. Robinson failed to note a single other factor as he claims he considers for all items of investment.

Q. DID YOU SPECIFICALLY INQUIRE AS TO THE CATEGORIZATION OF INVESTMENT IN ACCOUNT 376 – DISTRIBUTION MAINS BETWEEN BARE STEEL, COATED STEEL, WRAPPED STEEL, ETC.?

A. Yes, yet the Company claims it does not keep track of steel mains by bare, coated, or wrapped steel.[18] In addition, I inquired as to the dollar level of retirement by year associated with Account 376.1 – Distribution Steel Mains by type of pipe. However, the Company again claimed that it did not maintain information associated with its investment or retirement of such investment in steel mains by type of steel. Therefore, Mr. Robinson's brief reference to bare steel versus coated steel or wrapped steel as considerations for future expectations in his 2008 Study either points to a longer ASL or are meaningless.

Q. TURNING TO ACCOUNT 376.2 – DISTRIBUTION MAINS – PLASTIC, DID MR. ROBINSON'S AND THE COMPANY'S PRESENTATION YIELD BETTER RESULTS THAN IT DID FOR STEEL MAINS?

A. No. For plastic Distribution mains, Mr. Robinson claims in numerous completed depreciation studies for other utilities he has experienced shorter lives for plastic mains than for steel mains, and that plastic mains are often installed in areas that experience higher growth and thus replacements.[19] In other words, the total additional other factors that he identifies under plant considerations for future expectations reference what he claims to be his experience with other systems and

[18] Response to MCC-156.
[19] 2008 Study Exhibit No._(EMR-1) at page 4-5.

thus may have nothing to do with this specific analysis or any particular item of information obtained from MDU's management. Moreover, such a limited item of information in no way supports an ASL as short as 47 years.

Q. IS MR. ROBINSON'S STATEMENT REGARDING PLASTIC MAINS HAVING A SHORTER LIFE THAN STEEL MAINS SUPPORTED BY HIS ANALYSIS IN OTHER PROCEEDINGS?

A. Not on a consistent basis. For the limited number of other studies provided by Mr. Robinson, the largest gas system analyzed had a much longer life for plastic mains than what Mr. Robinson proposed for steel mains.[20] In other words, some of the results Mr. Robinson recommended for other utilities are inconsistent with his claim in this proceeding, thus calling into question the credibility of the very limited other generalized statement he presented in his 2008 Study.

Q. IN REVIEW OF MR. ROBINSON'S OTHER STUDIES, DID YOU FIND INDICATIONS THAT HE RECOMMENDS LONGER ASLs FOR DISTRIBUTION MAINS ELSEWHERE?

A. Yes. While Mr. Robinson's recommendations for mains generally appear to be lower than the recommendations elsewhere in the industry, he often does recommend ASLs for other utilities significantly longer than the 47-year ASL he proposes for MDU in this proceeding. Thus, it has to be questioned why Mr. Robinson believes that MDU has not or cannot obtain the same life expectancy for its Distribution mains as other utilities are able to do, even those that Mr. Robinson analyzes.

[20] Response to MCC-161.

C. Gas Plant Account 376

Q. DO YOU AGREE WITH MR. ROBINSON'S PROPOSED 47-YEAR ASL FOR DISTRIBUTION MAINS?

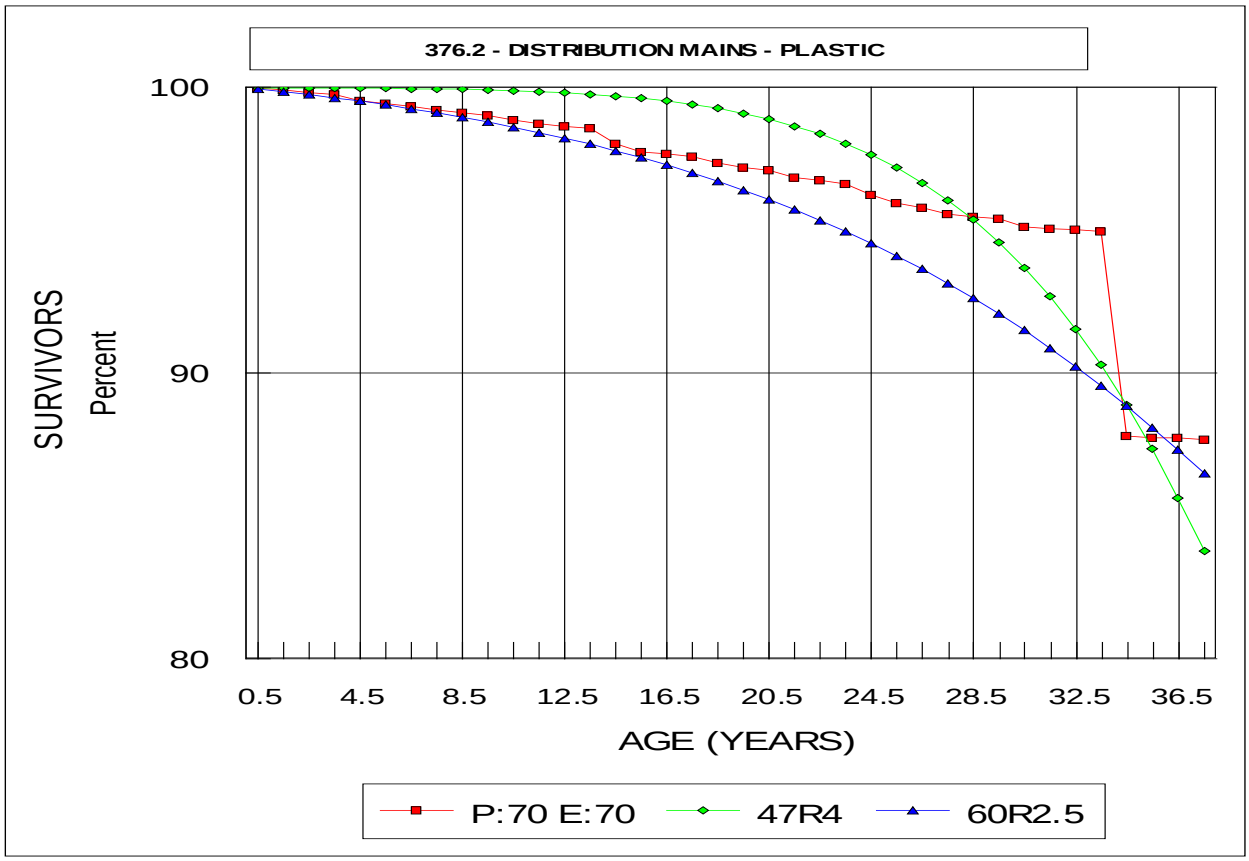
A. No. As previously noted, absent a strong showing in support of such an artificially short value, the ASL must be increased. I recommend an initial step to a 60R2.5 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

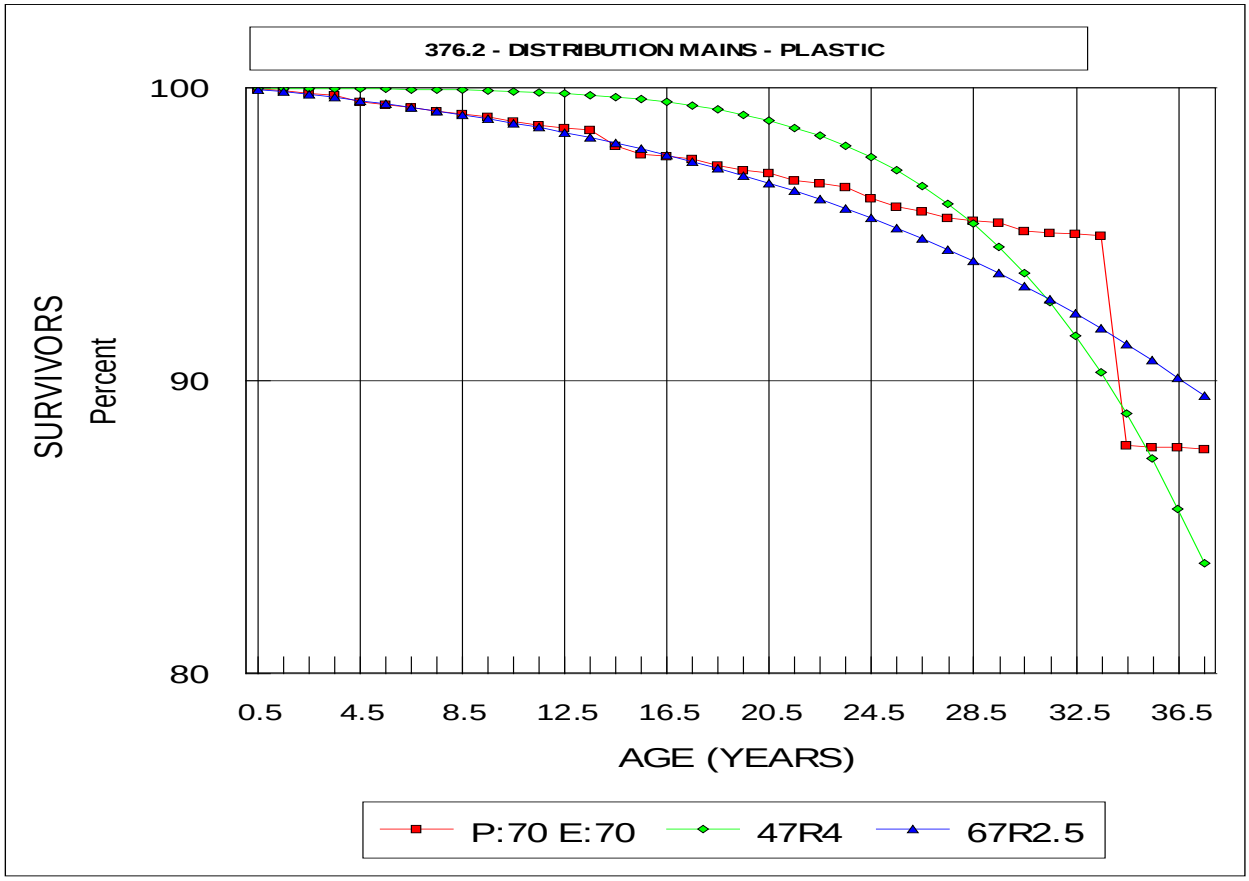
A. My recommendation is based on a combination of investigations into statistical results of the historical data, an understanding of the changes in the industry, and realistic industry expectations.

While Mr. Robinson claims he performed a statistical SPR analysis, the only limited results he did provide indicate much longer ASLs than either the 47-year level he proposed or the 60-year level I recommend.[21] However, in reviewing what limited information Mr. Robinson has provided, there is aged information for plastic and steel mains.[22] Based on my interpretation of what Mr. Robinson presented for age data associated with plastic and steel mains, I performed actuarial analyses which yielded good-fitting indications in the 60- to 70-year ASL range. As set forth in the graph below, my recommendation of a 60R2.5 life-curve combination is a far superior curve fit to the historic data or observed life table (i.e., the result from an actuarial analysis) for plastic mains than is Mr. Robinson's proposed 47R4 life-curve combination.

[21] Response to MCC-150.
[22] Response to MCC-135.


376.2 - DISTRIBUTION MAINS - PLASTIC
SURVIVORS
Percent
100
90
80
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
AGE (YEARS)
P:70 E:70
47R4
60R2.5

While the 60R2.5 life-curve combination is a good fit, as shown in the graph below a 67R2.5 life-curve combination is even a better fit for plastic mains.



However, until the Company provides more information for its investment and the life characteristics for its investment in the next depreciation study, I have limited the level of increase in ASL to the 60-year level.

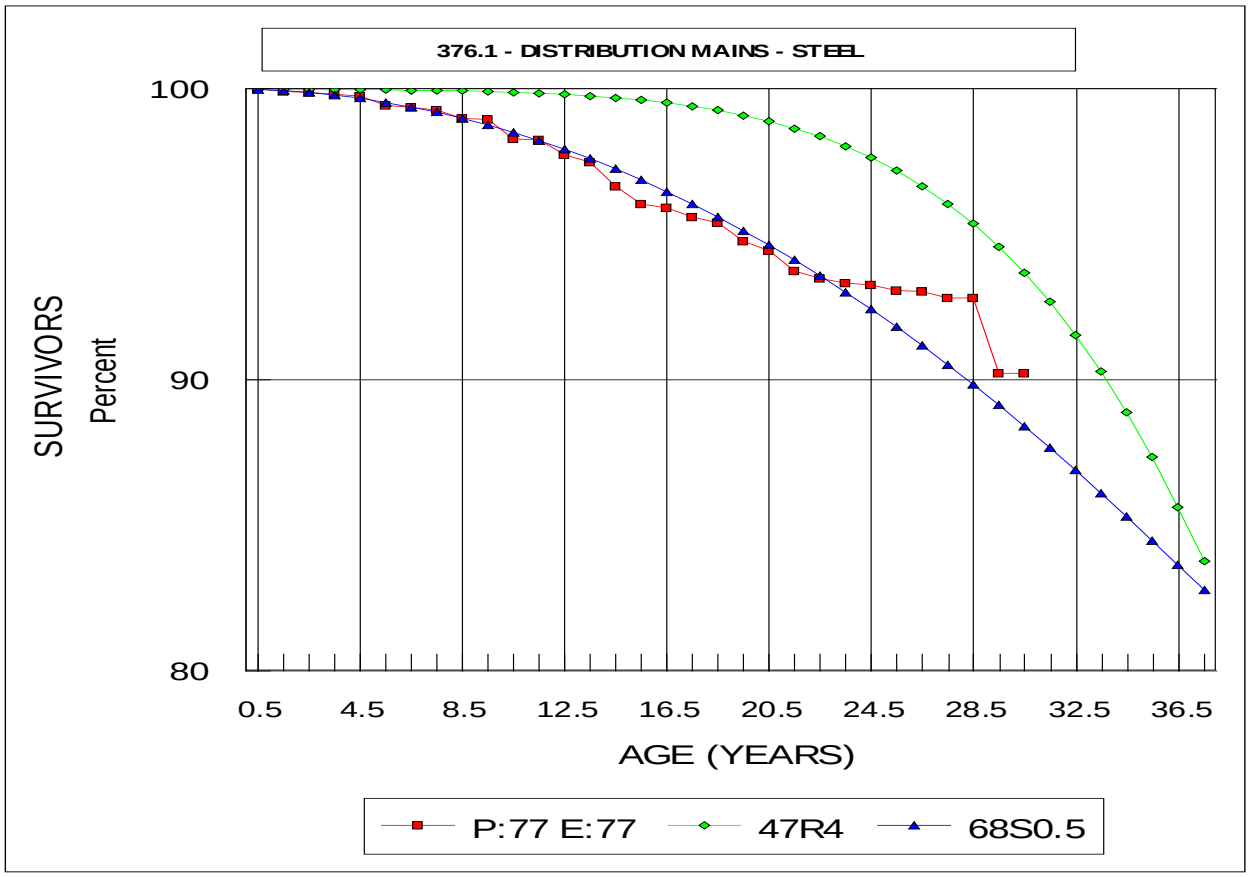
It must be noted that 45- to 55-year life indication for plastic mains is more indicative of early generations of plastic pipe installed in the 1960s and early 1970s that had chemical composition problems as well as installation problems. Such problems resulted in shorter life expectancy for such investment compared to life expectations for newer generation plastic pipe installed in the 1980s, 1990s, and 2000s. Given that the vast majority of investment in this account for MDU was placed into service after the 1980s, one would expect that the 60- to 70-year

ASLs indicated by the actuarial analysis to be more appropriate than Mr. Robinson's proposed 47-year ASL for plastic mains.

The actuarial information for steel mains is more limited than that for plastic mains, but still indicates a much longer life. As set forth in the graph below, a 68S0.5 life-curve combination is a superior fit to the observed life table than is Mr. Robinson's proposed 47R4 life-curve combination. Therefore, given the conservative estimate I recommend for plastic mains, such a recommendation would also be conservative for steel mains.

Turning to industry comparative data, it must be noted that even Mr. Robinson in his limited number of gas cases during the past five years has also proposed ASLs for Distribution mains in the mid-60- to even the mid-70-year level.[23] In other words, given the heavier weighting of investment to more current periods (e.g., the 1980s through the present), ASLs in the 60- to 70-year range are indicative of industry expectations and values even proposed by Mr. Robinson.

[23] Response to MCC-161.



In summary, whether viewed from the limited SPR results Mr. Robinson was prepared to provide, to limited actuarial analysis, to Mr. Robinson's own industry comparative data, or to other industry comparative data as well as recognition of the change in material and installation practices during the past several decades[24], an ASL no shorter than 60 years for Distribution mains should be adopted for any subaccount that Mr. Robinson proposed a 47-year ASL.

[24] Responses to MCC-179 and 180.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation for an initial step to a 60-year R2.5 life-curve combination results in a $1,043,790 reduction in total Company depreciation expense based on plant as of December 31, 2008.

D. Common Plant Life Analysis

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony will address the Company's proposed life for Common plant Account 390. Common plant Account 390 is by far the largest single Common plant account and has the largest depreciation expense for any Common plant account. For this account, Mr. Robinson proposes a 35-year ASL. Given the type of investment in the account, a 35-year ASL is artificially short.

Q. WHAT DOES THE COMPANY PROPOSE FOR COMMON PLANT ACCOUNT 390 – STRUCTURES & IMPROVEMENTS?

A. The Company proposes a 35R1 life-curve combination.[25]

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. As was the case for Gas plant, the Company's basis for its actual proposals for each account is limited to vague and generalized statements relating to analysis of historical information and discussion with Company personnel. However, for Common plant, Mr. Robinson performed actuarial analyses rather than SPR analyses as he performed for Gas plant. In performing actuarial analyses Mr. Robinson did provide the resulting observed life tables. The observed life tables associated with actuarial analyses provides more information than the graphical

[25] Exhibit No._(EMR-2) page 2-5 Column I.

presentation of simulated balances to actual balances, which is all he provided in the SPR analyses for Gas plant.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal represents an artificially short ASL. I recommend nothing shorter than a 55R1 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation not only reviews the results of the actuarial analyses, but unlike Mr. Robinson recognizes the actual type of investment in the account.

In particular, the vast majority of the investment in this account is associated with major office buildings and service centers.[26] These investments are steel buildings with either brick or pre-cast concrete exteriors and are owned, not leased, by the Company. Therefore, the retirement activity reflected in the actuarial results (e.g., roofs, A/C systems, etc.) relied upon by Mr. Robinson will significantly understate the life expectancy of the majority of the investment in the account (e.g., steel structures). Moreover, Mr. Robinson's actuarial analyses are inappropriately skewed to an artificially short ASL due to the inclusion of major retirements associated with transfer of the corporate office building to MDU Resources Corporation 6 years after completion.[27] Office buildings, warehouses, and service centers can and do last for 60 or 70 years or even longer periods. Indeed, MDU's general office in Bismarck, North Dakota was built in 1968 and is still in service with no identified plans for retirement. In other words, the largest single investment in this account has already lasted 45 years compared to Mr. Robinson's proposed 35-year ASL for this account.

[26] Response to MCC-148.
[27] Responses to MCC-185 through 187.

While the replacement of air conditioning systems, roofs, and other interim retirements will have an impact on the overall ASL for this account, a 35-year ASL is unrealistically short. Recognizing that the majority of the investment in this account is in actual steel buildings that can last for 60 or 70 years or longer, relying on a 55-year ASL is a more realistic expectation for the investment by the Company. This would be equivalent to assuming approximately a 70-year life span for the buildings and a 20-year life span for roofs and air conditioning systems, with a 70/30 split in investment, respectively. While the assumed 70/30 split between buildings and interim components is conservative, it does provide a logical basis at arriving at a 55-year overall ASL.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $263,866 reduction to total Company Common plant depreciation expense based on plant as of December 31, 2008.

SECTION IV: NET SALVAGE

A. Gas Plant Net Salvage General

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the Company's request for significant levels of negative net salvage in its calculation of Gas plant depreciation expense. Indeed, the Company's request reflects the fact that a majority of its requested depreciation expense is associated with its proposed net salvage parameters.[28]

[28] Reliance on a zero net salvage would reduce depreciation expense by $5.9 million, or 57.8% based on plant as of December 31, 2008.

Q. GIVEN THE SIGNIFICANCE OF THE COMPANY'S REQUESTED NET SALVAGE, DID IT PROVIDE DETAILED EXPLANATION AND SUPPORT FOR ITS REQUEST FOR VARIOUS ACCOUNTS?

A. No. In spite of the magnitude of the impact associated with the proposed net salvage values, Mr. Robinson presents little more than generalized statements that he performed historical analysis, attempted to identify trends, and was influenced by future estimates of the cost of removal based on age consideration of plant retired compared to the estimated ASL.[29] Indeed, a review of Mr. Robinson's testimony, 2008 Study, and workpapers yields the stark fact that the Company's proposed net salvage ratios are unsubstantiated and unsupported. It is essential to recognize that generalized phrases of performing historical analysis and considering future expectations are meaningless in establishing whether a -50%, a -30%, or any other value is the appropriate value to be utilized for ratemaking purposes for any given account.

Q. IS THERE A PARTICULAR CONCERN REGARDING MR. ROBINSON'S APPARENT PROCESS FOR ESTABLISHING NET SALVAGE VALUES?

A. Yes. Mr. Robinson incorporates his estimate of future inflation into his determination of net salvage ratios to be utilized for current ratemaking purposes. Mr. Robinson employs a methodology not utilized by others in the industry in order to provide his estimated quantification of future inflation. Indeed, in this proceeding, Mr. Robinson assumes a 2.75% annual future inflation rate for as long as 57 years into the future for one minor account, but also as far as 37 years into the future for a major account.[30]

[29] Mr. Robinson's testimony at pages 5, 15, and 18.
[30] 2008 Study Exhibit No._(EMR-1) Section 7 pages 7-3 and 7-13, respectively.

Q. DOES MR. ROBINSON'S UNIQUE PROCESS OF QUANTITATIVELY INCORPORATING A CALCULATION OF FUTURE INFLATION HAVE A SIGNIFICANT IMPACT?

A. Yes. For the largest single account, Distribution mains, Mr. Robinson's assumption that future inflation is the only consideration to be recognized for estimating future net salvage results in a current expected dollar of net salvage being increased to a level of $2.71.[31] In other words, Mr. Robinson wants current customers to pay for future escalated costs with their current dollars. This proposal is inappropriate as, at a minimum, it creates intergenerational inequity and violates the matching principle.

Q. IS MR. ROBINSON CORRECT IN ASSUMING FUTURE INFLATION APPLIED TO HISTORICAL ANALYSES IS THE APPROPRIATE APPROACH TO ESTIMATING FUTURE NET SALVAGE?

A. No, and in this particular instance there are additional problems to Mr. Robinson's analyses. First, it must be noted that if inflation were the only consideration for changes in future net salvage, there would be no need to hire a depreciation expert to quantify the impact that such a driving factor would have on the final determination of net salvage. In reality, even the historical analysis Mr. Robinson has presented clearly demonstrates that there is not a continuous increase in negative net salvage as would be expected if inflation were the driving or major factor associated with gross salvage and cost of removal. Indeed, there are numerous other factors and considerations that go into net salvage analyses. Unfortunately, Mr. Robinson fails to focus on any factor other than his estimate of future inflation.

[31] 2.75% annual inflation rate for 36.8 years compounded annually results in a 2.71 factor.

Q. WHAT ARE SOME OTHER FACTORS THAT SHOULD BE CONSIDERED?

A. Some of the other factors that affect net salvage are the circumstances associated with a particular retirement, the internal accounting for costs incurred between a new installation that replaces the retired plant, the actual item being retired within an account, the quantity of assets retired at any given time, as well as other considerations. For example, the per unit cost to remove a 10-foot section of main can be dramatically different depending on several factors. The cost to remove a 10-foot section of main on a three-day holiday weekend at 2 a.m. under emergency situations is going to be dramatically higher than the cost to remove a 10-foot section that is part of a one-mile replacement of mains on a planned basis during normal work hours. The per unit cost of removal between these two examples could be different by an order of magnitude.

Q. EVEN IF ONE WERE TO ASSUME INFLATION WAS THE KEY FACTOR IN ESTIMATING FUTURE NET SALVAGE, HAS MR. ROBINSON'S ASSUMED 2.75% ANNUAL INFLATION RATE BEEN ACCURATE IN THE YEARS THAT HAVE PASSED SINCE THE 2008 DEPRECIATION STUDY?

A. No. Inflation as measured by the Consumer Price Index (CPI) from the end of the 2008 Study through 2012 was 6.6%.[32] The 6.6% increase in CPI over the past four years compares to Mr. Robinson's estimation of 11.5% for the same period.[33] Indeed, during the four years subsequent to Mr. Robinson's depreciation study, his estimation of future inflation is in error by 73%.[34]

[32] U.S. Bureau of Labor Statistics CPI Index December 2012 value of 229.594 versus December 2008 value of 215.303.
[33] 1.0275^4=11.5%.
[34] 11.5% / 6.6%.

Q. HOW DID MR. ROBINSON TAKE INFLATION INTO ACCOUNT?

A. As with the balance of Mr. Robinson's depreciation study, his explanation of how he incorporated his concept of future inflation into the development of his final proposed net salvage parameters is extremely vague. When specifically requested to provide how annual inflation was employed in the development of the final proposed net salvage parameters, Mr. Robinson responded by saying the forecast is an "additional tool used to provide information."[35] He further states that his estimation process "gives consideration to the overall average, recent experience, and forecasted analysis. The estimation process is one of gradualism towards more future looking calculations which is more representative of future net salvage that can be anticipated at the end of life of the property group."[36] In other words, even when specifically requested to provide how he employed his inflation calculation in determining the final proposed net salvage values, he continues the process of being exceptionally vague and nonresponsive to what he actually did to arrive at net salvage factors. This failure to identify what is the basis for his proposal is inappropriate and unacceptable given that his net salvage estimations represent the majority of the requested depreciation expense. As will be discussed in the account specific section of my testimony, Mr. Robinson's failure to provide specifics appear to be tied in part to the significance he actually did give to his future inflation estimates in his process of proposing net salvage values for accounts.

Q. BASED ON YOUR REVIEW OF THE MAJOR GAS PLANT ACCOUNTS, ARE YOU RECOMMENDING ADJUSTMENTS?

A. Yes. I am recommending adjustments to the three major Gas plant accounts which comprise in excess of 90% of the depreciation expense requested in the 2008

[35] Response to MCC-143.
[36] *Id.*

Study. The table below sets forth for the three accounts, the Company's proposals, my recommendations, and the standalone difference of each recommendation on a total Company basis as of December 31, 2008.

Account Description	**MDU Proposed**	**MCC Recommended**	**Impact of Adjustment**
Account 376 – Distribution Mains	-50%	-30%	$761,817
Account 380 – Distribution Services	-200%	-175%	$507,095
Account 381 – Distribution Meters	-15%	-5%	$228,078
Total			$1,496,990

In addition, I am recommending an adjustment to Common plant Account 390 – Structures & Improvements.

B. Gas Plant Account Specific

Account 376

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 376 – DISTRIBUTION MAINS?

A. The Company proposes a -50% net salvage, which is less negative than the existing -60% net salvage for this account.[37]

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company presents no specific basis for its proposal. As previously noted, Mr. Robinson has provided various generalized and vague references to concepts, trends, and other information, yet has failed to provide any specifics as to how he arrived at his proposed -50% net salvage value.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is excessively negative. I recommend a -30% net salvage for this account.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on an analysis of historical data recognizing patterns or trends in the data and taking into account the likely type of activity that is occurring. First, it must be noted that while Mr. Robinson claims that he relies on trends in the data for this account, that statement is not accurate. The trend in the data from the early 2000s through 2008 has been generally to a less negative level between approximately -20% and -30%.[38] Indeed, even relying on the three-year rolling average band analyses presented by Mr. Robinson, the trend has also been

[37] 2008 Study Exhibit No._(EMR-1) Section 4 page 4-4.
[38] 2008 Study Exhibit No._(EMR-1) at page 7-10.

towards a -25% to -35% value.[39] Moreover, it is worth noting that during the past 20 years the Company has experienced a value as negative as a -50% in only two years.[40] In fact, for four out of the past five years, the Company has experienced a negative net salvage less negative than a -35%. Therefore, from a trend analysis or analysis of historical data, a net salvage value between -25% and -30% would be more appropriate.

Another consideration is the fact that on systems such as the Company's, without identified main replacement programs, mains are frequently replaced due to emergency situations. The level of negative net salvage that is incurred during emergency replacement activity is normally more negative than would normally be expected in the future, as a greater quantity of mains are retired on a more planned basis.

In addition, my recommendation is approximately the level experienced by the Company over the entire historical database relied upon by Mr. Robinson in his 2008 Study.[41] I, however, did not incorporate the impact of estimated future inflation as did Mr. Robinson. In fact, for this account, it would appear that the only pathway to a -50% net salvage as proposed by Mr. Robinson would be to give significant weight to his future inflated -92% value. Indeed, it would be necessary to give Mr. Robinson's estimated future inflation results of a negative 92% an approximate 40% weighting with a 60% weighting for the current or trend values of approximately a -25% to -30% to arrive at an overall -50% net salvage level.[42] Such analysis by Mr. Robinson is inappropriate and demonstrates the fatal flaw reflected in his proposal.

[39] *Id*. at page 7-12.
[40] *Id*. at pages 7-9 and 7-10.
[41] *Id*. at page 7-13.
[42] (-92% x 40% + -25% x 60%) = 51.8%.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation of a -30% net salvage for this account results in a $761,817 reduction in total Company annual depreciation expense based on plant as of December 31, 2008.

Account 380

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 380 – DISTRIBUTION SERVICES?

A. The Company proposes a -200% net salvage, or a value more negative than the existing
-175% net salvage.[43]

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. As with all other accounts, the Company provided no specific explanation as to how it arrived at its proposed -200% net salvage. However, the proposed -200% net salvage is approximately equal to the inflation adjusted forecasted future expected net salvage value developed by Mr. Robinson.[44]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is one of the most negative net salvage levels utilized in the industry. In fact, it must be realized that the Company's -200% net salvage represents a situation where the Company seeks to recover $3 from customers for every $1 it invests in Distribution services. Given the Company's lack of detailed information associated with its investment in this account, I conservatively recommend retaining the existing -175% net salvage.

[43] 2008 Study Exhibit No._(EMR-1) at Section 4 pages 4-11 through 4-13.
[44] 2008 Study Exhibit No._(EMR-1) at Section 7 page 7-28.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Company's historical values vary significantly over time. The range of values reported by the Company for years that cost of removal or gross salvage values are recorded range from a high of a -28% to a low of a -286%.[45] In addition, it is common for the Company to report annual variations of 40 percentage points or more. Annual variations of this magnitude call into question the Company's accounting practices as well as field practices associated with the retirement of services.

While the overall historical database presented by the Company yields a -88% net salvage, the overall value includes numerous years where no gross salvage or cost of removal was reported.[46] When the historical database is reviewed from 1995 through 2008, corresponding to the period when the Company did record gross salvage or cost of removal in each consecutive year, the resulting net salvage is a -179%. While a -179% is still excessively negative compared to industry values and realistic expectations, it may be the best information available given the Company's presentation.

From an industry standpoint, even one grounded in Mr. Robinson's recent experience, the proposed -200% net salvage for this account is excessively negative. Indeed, during the past five years the most negative net salvage value proposed by Mr. Robinson is a -160%, with the average proposed negative net salvage value being approximately a -88%.[47] In other words, even the existing -175% net salvage is more negative than any value Mr. Robinson proposed during the past five years and in fact is as much as <u>eight times</u> more negative than the -25% value he proposed for Rochester Gas & Electric for the same depreciation test period as reflected in the Company's 2008 Study. Variations of this

[45] *Id*. at Pages 7-24 through 7-25.
[46] *Id*. at Pages 7-24 through 7-28.
[47] Response to MCC-161.

magnitude demand significant support and justification, none of which has been provided by Mr. Robinson or the Company.

While I am uncomfortable recommending retention of even the -175% existing net salvage level, it is the only value that can reasonably be identified based on the information provided by the Company. However, in conjunction with recommending the retention of the -175% net salvage, I also recommend the Commission order the Company to make a full and complete analysis of why its recorded levels of negative net salvage are not only becoming more negative, but are at high negative levels compared to the rest of the industry. Such analysis should include a detailed review and justification of those costs directly assigned to cost of removal when replacement activity occurs. It may very well be a situation where activities that should be assigned to the new replacement investment are being booked as cost of removal. However, in no instance should the Commission adopt a more negative value than currently exists.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation to retain the -175% net salvage results in a $507,095 reduction in total Company annual depreciation expense based on plant as of December 31, 2008.

Account 381

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 381 – DISTRIBUTION METERS?

A. The Company proposes a significant change in net salvage. The Company proposes a -15% compared to the existing zero (0) level of net salvage.[48]

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. As with all other accounts, the Company does not provide any meaningful basis for how it arrived at its proposed net salvage value. However, based on a review of the Company's historical analysis of data, it would appear that the -15% proposal is based on Mr. Robinson's reliance on his forecast of future inflation, which results in a -19%. This future inflation escalated value of -19% and Mr. Robinson's statement that he gradually tends to move to the future inflated value, appears to support his -15% proposal.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is excessively negative. I recommend a value no more negative than a -5%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Review of the historical database indicates a positive overall 7% net salvage.[49] Further review of historical data indicates that, during just the past 10 years, the Company experienced a range from a high of positive 75% to a low of a -175%.[50] Moreover, the trend in the data based on three-year rolling averages is towards a less negative value but is heavily influenced by the most recent 2008 value

[48] 2008 Study Exhibit No._(EMR-1) at page 4-14.
[49] *Id*. at Page 7-33.
[50] *Id*. at Page 7-30.

corresponding to a -175%. Thus, to the extent that moving to a negative value is appropriate, nothing more negative than a -5% is warranted, and in fact, even such movement may be unwarranted. However, without any further additional information a -5% net salvage recommendation is a conservative value.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $228,078 reduction in total Company annual depreciation expense based on plant as of December 31, 2008.

C. Common Plant Net Salvage

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the Company's proposal for a zero (0) level of net salvage associated with Common plant Account 390 – General Structures & Improvements.

Q. WHAT DOES THE COMPANY PROPOSE FOR ITS COMMON PLANT ACCOUNT 390 – GENERAL PLANT STRUCTURES & IMPROVEMENTS?

A. The Company proposes a zero (0) net salvage for the investment in this account.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. As with all other proposals by the Company, there is no specific basis provided, either in testimony or in the 2008 Study. However, review of Mr. Robinson's net salvage presentation in Section 7 of his 2008 Study for Common plant indicates

that a significant positive net salvage is warranted based on either review of historical data or Mr. Robinson's forecasted inflation analysis.[51]

Q. DO YOU AGREE WITH MR. ROBINSON'S PROPOSAL?

A. No. Mr. Robinson's proposal significantly understates the realistic future net salvage expectations for this account. I recommend a positive 20% as a first step towards recognition of the true value these investments will produce when retired.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based both on an analysis of historical transactions by the Company and analysis of the type of investment that currently exists. From either standpoint, the positive 20% net salvage is the minimal first step that must be taken.

An analysis of the overall historical database relied upon by the Company yields a positive 21% net salvage.[52] In addition, the three-year rolling bands produced by Mr. Robinson of historical data indicate 50% to 90% positive net salvage values. Therefore, based on actual Company experience, a positive net salvage significantly in excess of positive 20% is warranted.

Further investigation into historical retirements of buildings further yields a strong historical pattern of positive net salvage value for such investments. Indeed, during the past 20 years the Company retired 11 general office structures.[53] In all instances, the Company experienced positive net salvage. In fact, the overall level of positive net salvage experienced by the Company for its retirement of general office structures during the past 20 years was in excess of a positive 100%.[54] Not only is a large positive net salvage demonstrated by Company actual experience,

[51] 2008 Study Common plant Exhibit No._(EMR-2) Section 7 pages 7-1 through 7-5.
[52] *Id.* at page 7-5.
[53] Response to MCC-149.
[54] *Id.*

but is consistent with both logic and common sense. A building, if constructed appropriately and maintained over its useful life for a particular owner, is normally expected to have a significant positive level of net salvage. Given that the vast majority of the Company's investment in this account currently corresponds to steel office buildings, there is no reasonable expectation that it will receive a zero (0) level of net salvage when it does retire such facilities.

Finally, it must be noted that had Mr. Robinson given consideration to his forecasted future net salvage calculations as he has done in other accounts, he would have recognized a value significantly in excess of a positive 20% net salvage. A value much greater than a positive 20% represents a net salvage value more positive than the level I recommend in this proceeding.

In summary, whether viewed from a standpoint of the overall actual data for the account, the actual experience for 11 buildings retired over the last 20 years, the standard understanding of appreciation of buildings over time that are appropriately constructed and maintained, recognition of the type of investment currently in service, or even Mr. Robinson's forecast analyses, there is no logical basis for assuming a zero (0) net salvage as proposed by the Company. My recommended positive 20% net salvage should be viewed as a very conservative initial step in conjunction with the recommendation that the Commission order the Company to perform a detailed analysis of reasonable net salvage expectations for its investment in office buildings to be incorporated in the Company's next depreciation study.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $283,205 reduction to total Company depreciation expense based on plant as of December 31, 2008.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, to the extent I have not addressed an issue, method, procedures, or other matter relevant to the Company's rate case, it should not be construed that I am in agreement with the Company's proposed issue, method, or procedures.

JACOB POUS, P.E.

PRESIDENT, DIVERSIFIED UTILITY CONSULTANTS, INC.

B.S. INDUSTRIAL ENGINEERING, M.S. MANAGEMENT

I graduated from the University of Missouri in 1972, receiving a Bachelor of Science Degree in Engineering, and I graduated with a Master of Science in Management from Rollins College in 1980. I have also completed a series of depreciation programs sponsored by Western Michigan University, and have attended numerous other utility related seminars.

Since my graduation from college, I have been continuously employed in various aspects of the utility business. I started with Kansas City Power & Light Company, working in the Rate Department, Corporate Planning and Economic Controls Department, and for a short time in a power plant. My responsibilities included preparation of testimony and exhibits for retail and wholesale rate cases. I participated in cost of service studies, a loss of load probability study, fixed charge analysis, and economic comparison studies. I was also a principal member of project teams that wrote, installed, maintained, and operated both a computerized series of depreciation programs and a computerized financial corporate model.

I joined the firm of R. W. Beck and Associates, an international consulting engineering firm with over 500 employees performing predominantly utility related work, in 1976 as an Engineer in the Rate Department of its Southeastern Regional Office. While employed with that firm, I prepared and presented rate studies for various electric, gas, water, and sewer systems, prepared and assisted in the preparation of cost of service studies, prepared depreciation and decommissioning analyses for wholesale and retail rate proceedings, and assisted in the development of power supply studies for electric systems. I resigned from that firm in November 1986 in order to co-found Diversified Utility Consultants, Inc. At the time of my resignation, I held the titles of Executive Engineer, Associate and Supervisor of Rates in the Austin office of R. W. Beck and Associates.

As a principal of the firm of Diversified Utility Consultants, Inc., I have presented and prepared numerous electric, gas, and water analyses in both retail and wholesale proceedings. These analyses have been performed on behalf of clients, including public utility commissions, throughout the United States and Canada.

I have been involved in over 400 different utility rate proceedings, many of which have resulted in settlements prior to the presentation of testimony before regulatory bodies. I am registered to practice as a Professional Engineer in many states.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY JACOB POUS

ALASKA		
ALASKA REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Beluga Pipe Line Company	P-04-81	Refundable Rates
Beluga Pipe Line Company	U-07-141	Depreciation
Kenai Nikiski Pipeline	U-04-81	Rate Base
ARIZONA		
ARIZONA CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Citizens Utilities Company	E-1032-93-111	Depreciation
ARKANSAS		
ARKANSAS PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Reliant Energy ARKLA	01-0243-U	Depreciation
CALIFORNIA		
CALIFORNIA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Pacific Gas & Electric Company	App. No. 97-12-020	Depreciation, Net Salvage, and Amortization of True-Up
Pacific Gas & Electric Company	App. No. 02-11-017	Mass Property Salvage, Net Salvage, Mass Property Life, Life Analysis, Remaining Life, Depreciation
San Diego Gas & Electric Company		Value of Power Plants
Southern California Edison Company	App 02-05-004	Depreciation, Net Salvage
Southern California Edison Company	App 10-11-015	Mass Property Life and Net Salvage
Southern California Gas & San Diego Gas & Electric Company	Apps 10-12-005 & 10-12-006	Mass Property Life, Mass Property Net Salvage
CANADA		
ALBERTA ENERGY AND UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
AltaLink Management/ Transalta Utilities Corporation	App. Nos. 1279345 and 1279347	Depreciation
Epcor Distribution, Inc.	App. No. 1306821	Depreciation
Enmax Corporation	App. No. 1306818	Depreciation
Transalta Utilities Corporation	TFO Tariff App. 1287507	Depreciation
UtiliCorp Networks Canada (Alberta) Ltd.	App. No. 1250392	Depreciation
Atco Electric	App. No. 1275494	Depreciation
ALBERTA PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Alberta Power Limited	E 91095	Depreciation
Alberta Power Limited	E 97065	Depreciation

Canadian Western Natural Gas Company, Ltd.		Depreciation
Centra Gas Alberta, Inc.		Depreciation
Edmonton Power Company	E 97065	Depreciation
Edmonton Power Generation, Inc.	1999/2000	GUR Compliance, Depreciation
Northwestern Utilities, Ltd	E 91044	Depreciation
NOVA Gas Transmission, Ltd.	RE95006	Depreciation
TransAlta Utilities Corporation	E 91093	Depreciation
TransAlta Utilities Corporation	E 97065	Depreciation
TransAlta Utilities Corporation	App. No. 200051	Gain on Sale
ALBERTA UTILITIES COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
AltaGas Utilities	1606694	Life Analysis, Net Salvage
AltaLink Management, Ltd.	1606895	Life Analysis, Net Salvage
ATCO Gas	1606822	Life Analysis, Net Salvage
FortisAlberta	1607159	Life Analysis, Net Salvage
NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES		
Newfoundland & Labrador Hydro		Depreciation, Life Analysis
Newfoundland Power, Inc.	2013/2014	Depreciation, Life Analysis, Net Salvage, ELG vs. ALG
NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Northwest Territories Power Corporation	1995/96 and 1996-97	Depreciation
Northwest Territories Power Corporation	2001	Depreciation
NOVA SCOTIA UTILITY AND REVIEW BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Nova Scotia Power, Inc.	M03665	Production Plant Life and Net Salvage (Inflation), Interim Retirements, Mass Property Life and Net Salvage, ELG vs. ALG, Remaining Life, Fully Accrued
COURTS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
7th Judicial Circuit Court of Florida	2008-30441-CICI	Depreciation Valuation
112th Judicial District Court of Texas	5093	Ratemaking Principles, Calculation of damages
253rd Judicial District Court of Texas	45,615	Ratemaking Principles, Level of Bond
126th Judicial District Court of Texas	91-1519	Ratemaking Principles, Level of Bond
172 Judicial District Court of Texas		Franchise Fees
United States Bankruptcy Court Eastern District of Texas	93-10408S	Level of Harm, Ratemaking, Equity for Creditors
3rd Judicial District Court of Texas		Adequacy of Notice
DISTRICT OF COLUMBIA		
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Washington Gas Light Company	768	Depreciation
FLORIDA		

FLORIDA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Progress Energy Florida, Inc.	090079-EI	Depreciation, Excess Reserve
Progress Energy Florida, Inc.	050078-EL	Depreciation, Excess Reserve
Florida Power & Light Company	790380-EU	Territorial Dispute
Florida Power & Light Company	080677-EI 090130-EI	Depreciation, Excess Reserve
Florida Power & Light Company	120015-EI	Excess Reserve
Florida Power & Light Company	120015-EI	Settlement Analysis
FEDERAL ENERGY REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Alabama Power Company	ER83-369	Depreciation
Connecticut Municipal Electric Energy Cooperative v. Connecticut Light & Power Company	EL83-14	Decommissioning
Florida Power & Light Company	ER84-379	Depreciation, Decommissioning
Florida Power & Light Company	ER93-327-000	Transmission Access
Georgia Power Company	ER76-587	Rate Base
Georgia Power Company	ER79-88	Depreciation
Georgia Power Company	ER81-730	Coal Fuel Stock Inventory, Depreciation
ISO New England, Inc.	ER07-166-000	Depreciation
Maine Yankee Atomic Power Company	ER84-344-001	Depreciation, Decommissioning
Maine Yankee Atomic Power Company	ER88-202	Decommissioning
Pacific Gas & Electric	ER80-214	Depreciation
Public Service of Indiana	ER95-625-000, ER95-626-000 & ER95-039-000	Depreciation, Dismantlement
Southern California Edison Company	ER81-177	Depreciation
Southern California Edison Company	ER82-427	Depreciation, Decommissioning
Southern California Edison Company	ER84-75	Depreciation, Decommissioning
Southwestern Public Service Company	EL 89-50	Depreciation, Decommissioning
System Energy Resource, Inc.	ER95-1042-000	Depreciation, Decommissioning
Vermont Electric Power Company	ER83 342000 & 343000	Decommissioning
Virginia Electric and Power Company	ER78-522	Depreciation, Rate Base
INDIANA		
INDIANA UTILITY REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Indianapolis Water Company	39128	Depreciation
Indiana Michigan Power Company	39314	Depreciation, Decommissioning
KANSAS		
KANSAS CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Arkansas Louisiana Gas Company	181,200-U	Depreciation
United Cities Gas Company	181,940-U	Depreciation
LOUISIANA		

LOUISIANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Louisiana Power & Light Company	U-16945	Nuclear Prudence, Depreciation
CITY OF NEW ORLEANS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Entergy New Orleans, Inc.	UD-00-2	Rate Base, Depreciation
MASSACHUSETTS		
MASSACHUSETTS TELECOMMUNICATION AND ENERGY		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Bay State Gas	D.T.E.-0527	Depreciation
National Grid/KeySpan	07-30	Quality of Service
MISSISSIPPI		
MISSISSIPPI PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Mississippi Power Company	U-3739	Cost of Service, Rate Base, Depreciation
MONTANA		
MONTANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Montana Power Company (Gas)	90.6.39	Depreciation
Montana Power Company (Electric)	90.3.17	Depreciation, Decommissioning
Montana Power Company (Electric and Gas)	95.9.128	Depreciation
Montana-Dakota Utilities	D2007.7.79	Depreciation
Montana-Dakota Utilities	D2010.8.82	Depreciation, Interim Retirements, Production Plant Life and Net Salvage
NEVADA		
PUBLIC UTILITIES COMMISSION OF NEVADA		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Nevada Power Company	81-602, 81-685 Cons.	Depreciation
Nevada Power Company	83-667, Consolidated	Depreciation
Nevada Power Company	91-5032	Depreciation, Decommissioning
Nevada Power Company	03-10002	Depreciation
Nevada Power Company	08-12002	Depreciation, CWC
Nevada Power Company	06-06051	Depreciation, Life Spans, Decommissioning Costs, Deferred Accounting
Nevada Power Company	06-11022	General Rate Case
Nevada Power Company	10-02009	Production Life Spans
Nevada Power Company	11-06007	Early Retirement, Production Plant Net Salvage, Mass Property Life, Mass Property Net Salvage, Excess APFD
Sierra Pacific Gas Company	06-07010	Depreciation, Generating Plant Life Spans, Decommissioning Costs, Carrying Costs
Sierra Pacific Power Company	83-955	Depreciation (Electric, Gas, Water, Common)

Sierra Pacific Power Company	86-557	Depreciation, Decommissioning
Sierra Pacific Power Company	89-516, 517, 518	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	91-7079, 80, 81	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	03-12002	Allowable Level of Plant in Service
Sierra Pacific Power Company	05-10004	Depreciation
Sierra Pacific Power Company	05-10006	Depreciation
Sierra Pacific Power Company	07-12001	Depreciation, CWC
Sierra Pacific Power Company	10-06003	Depreciation, Excess Reserve, Life Spans, Net Salvage
Sierra Pacific Power Company	10-06004	Depreciation, Net Salvage
Sierra Pacific Power Company	12-08009	IRP-Coal Plant Service Life
Southwest Gas Corporation	93-3025 & 93-3005	Depreciation
Southwest Gas Corporation	04-3011	Depreciation
Southwest Gas Corporation	07-09030	Depreciation
Southwest Gas Corporation	12-04005	Depreciation
NORTH CAROLINA		
NORTH CAROLINA UTILITIES COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
North Carolina Natural Gas	G-21, Sub 177	Cost of Service, Rate Design, Depreciation
OKLAHOMA		
OKLAHOMA CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Arkansas Oklahoma Gas Corporation	PUD 200300088	CWC, Legal Expenses, Factoring, Cost Allocation, Depreciation
Oklahoma Natural Gas Company	PUD 980000683	Depreciation, Calculation Procedure, Depreciation on CWIP
Reliant Energy ARKLA	PUD 200200166	Depreciation, Net Salvage, Software Amortization
Public Service Company of Oklahoma	PUD 960000214	Depreciation, Interim Activity, Net Salvage, Mass Property, Rate Calculation Technique
Public Service Company of Oklahoma	PUD 200600285	Depreciation
Public Service Company of Oklahoma	PUD 200800144	Depreciation
Public Service Company of Oklahoma	PUD 201000050	Depreciation, Evaluation vs. Measurement, Interim and Terminal Net Salvage, Economies of Scale
Oklahoma Gas & Electric	PUD 201100087	Depreciation
TEXAS		
PUBLIC UTILITY COMMISSION OF TEXAS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
CenterPoint Energy Houston Electric, LLC	29526	Stranded Costs
CenterPoint Energy Houston Electric, LLC	36918	Hurricane Cost Recovery
CenterPoint Energy Houston Electric, LLC	38339	Depreciation, Net Salvage, Excess Reserve, Gain on Sale

Central Power & Light Company	6375	Depreciation, Rate Base, Cost of Service
Central Power & Light Company	8439	Fuel Factor
Central Power & Light Company	8646	Rate Base, Excess Capacity, Depreciation, Rate Design, Rate Case Expense
Central Power & Light Company	9561	Depreciation, Excess Capacity, Cost of Service, Rate Base, Taxes
Central Power & Light Company	11371	Economic Development Rate
Central Power & Light Company	12820	Nuclear Fuel and Process, OPEB, Pension, Factoring, Depreciation
Central Power & Light Company	14965	Depreciation, Cash Working Capital, Pension, OPEB, Factoring, Demonstration and Selling Expense, Non-Nuclear Decommissioning
Central Power & Light Company	22352	Depreciation
Central Telephone & United Telephone Company of Texas d/b/a Sprint	17809	Rate Case Expenses
City of Fredericksburg	7661	Territorial Dispute
El Paso Electric Company	9165	Depreciation
Entergy Gulf States, Inc.	16705	Depreciation, Prepayments, Payroll Expense, Pension Expense, OPEB, CWC, Transfer of T&D Depreciation
Entergy Gulf States, Inc.	21111	Reconcilable Fuel Costs
Entergy Gulf States, Inc.	21384	Fuel Surcharge
Entergy Gulf States, Inc.	23000	Fuel Surcharge
Entergy Gulf States, Inc.	22356	Unbundling, Competition, Cost of Service
Entergy Gulf States, Inc.	23550	Reconcilable Fuel Costs
Entergy Gulf States, Inc.	24336	Price to Beat
Entergy Gulf States, Inc.	24460	Implement PUC Subst.R.25.41(f)(3)(D)
Entergy Gulf States, Inc.	24469	Delay of Deregulation
Entergy Gulf States, Inc.	24953	Interim Fuel Surcharge
Entergy Gulf States, Inc.	26612	Fuel Surcharge
Entergy Gulf States, Inc.	28504	Interim Fuel Surcharge
Entergy Gulf States, Inc.	28818	Cert. for Independent Organization
Entergy Gulf States, Inc.	29408	Fuel Reconciliation
Entergy Gulf States, Inc.	30163	Interim Fuel Surcharge
Entergy Gulf States, Inc.	31315	Incremental Purchase Capacity Rider
Entergy Gulf States, Inc.	31544	Transition to Competition Cost
Entergy Gulf States, Inc.	32465	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32710	River Bend 30%, Explicit Capacity, Imputed Capacity, IPCR, SGSF Operating Costs and Depreciation Recovery, Option Costs
Entergy Gulf States, Inc.	33687	Transition to Competition
Entergy Gulf States, Inc.	33966	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32907	Hurricane Reconstruction
Entergy Gulf States, Inc.	34724	IPCR

Entergy Gulf States, Inc.	34800	JSP, Depreciation, Decommissioning, Amortization, CWC, Franchise Fees, Rate Case Exp.
Entergy Texas Inc.	37744	Depreciation, Property Insurance Reserve, Cash Working Capital, Decommissioning Funding, Gas Storage
Entergy Texas Inc.	39896	Depreciation, Amortization, Property Insurance Reserve, Cash Working Capital
Gulf States Utilities Company	5560	Depreciation, Fuel Cost Factor
Gulf States Utilities Company	5820	Fuel Cost, Capacity Factors, Heat Rates
Gulf States Utilities Company	6525	Depreciation, Rate Case Expenses
Gulf States Utilities Company	7195 & 6755	Depreciation, Interim Cash Study, Excess Capacity, Rate Case Expense
Gulf States Utilities Company	8702	Rate Case Expenses, Depreciation
Gulf States Utilities Company	10,894	Fuel Reconciliation, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	11292	Acquisition Adjustment Regulatory Plan, Base Rate, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	12423	North Star Steel Agreement
Gulf States Utilities Company & Entergy Corporation	12852	Depreciation, OPEB, Pensions, Cash Working Capital, Other Cost of Service, and Rate Base Items
Houston Light & Power Company	6765	Depreciation, Production Plant, Early Retirement
Lower Colorado River Authority	8400	Rate Design
Magic Valley Electric Cooperative, Inc.	10820	Cost of Service, Financial Integrity, Rate Case Expenses
Oncor Electric Delivery, LLC	35717	Depreciation, Self-Insurance, Payroll, Automated Meters, Regulatory Assets, PHFU
Southwestern Bell Telephone Company	18513	Rate Case Expenses
Southwestern Electric Power Company	3716	Depreciation
Southwestern Electric Power Company	4628	Depreciation
Southwestern Electric Power Company	5301	Depreciation, Fuel Charges, Franchise Fees
Southwestern Electric Power Company	24449	Fuel Factor Component of Price to Beat Rates
Southwestern Electric Power Company	24468	Delay of Deregulation
Southwestern Public Service Company	11520	Depreciation, Cash Working Capital, Rate Case Expenses
Southwestern Public Service Company	32766	Depreciation Expense Revenue Requirements
Southwestern Public Service Company	35763	Depreciation
Texas-New Mexico Power Company	9491	Avoided Cost, Rate Case Expenses
Texas-New Mexico Power Company	10200	Jurisdictional Separation, Cost Allocation, Rate Case Expenses
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	36025	Depreciation
Texas-New Mexico Power Company	38480	Depreciation, Mass Property Life, Net Salvage

Texas Utilities Electric Company	5640	Franchise Fees
Texas Utilities Electric Company	9300	Depreciation, Rate Base, Cost of Service, Fuel Charges, Rate Case Expenses
Texas Utilities Electric Company	11735	Cost Allocation, Rate Design, Rate Case Expenses
Texas Utilities Electric Company	18490	Depreciation Reclassification
West Texas Utilities Company	7510	Depreciation, Decommissioning, Rate Base, Cost of Service, Rate Design, Rate Case Expenses
West Texas Utilities Company	10035	Fuel Reconciliation, Rate Case Expenses
West Texas Utilities Company	13369	Depreciation, Payroll, Pension, OPEB, Cash Working Capital, Fuel Inventory, Cost Allocation
West Texas Utilities Company	22354	Depreciation
RAILROAD COMMISSION OF TEXAS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Atmos Energy Corporation	9530	Gas Cost, Gas Purchases, Price Mitigation, Rate Case Expense
Atmos Energy Corporation	9670	CWC, Depreciation, Expenses, Shared Services, Taxes Other Than FIT, Excess Return
Atmos Energy Corporation	9695	Rate Case Expense
Atmos Energy Corporation	9762	Depreciation, O&M Expense
Atmos Energy Corporation	9732	Rate Case Expense
Atmos Energy Corporation	9869	Revenue Requirements
Atmos Energy Corporation	10041	Mass Property Life, Net Salvage
Atmos Energy Corporation	10170	Depreciation, Mass Property Life, Net Salvage
Atmos Pipeline-Texas	10000	Rate Base, Depreciation Life and Net Salvage, Incentive Compensation, Merit Increase, Outside Director Retirement Costs, SEBP
CenterPoint Energy Entex – City of Tyler	9364	Capital Investment, Affiliates
CenterPoint Energy Entex – Gulf Coast Division	9791	Rate Base, Cost Allocation, Affiliate Expenses, Depreciation Net Salvage, Call Center, Litigation, Uncollectibles, Post Test Year Adjustments
CenterPoint Energy Entex – City of Houston	9902	CWC, Plant Adjustments, Depreciation, Payroll, Pensions, Cost Allocation
CenterPoint Energy Entex – South Texas Division	10038	CWC, Incentive Compensation, Payroll, Depreciation
CenterPoint Energy – Beaumont/East Texas	10182	Rate Base, Expense, Incentive Compensation, Pension, Payroll, Injuries & Damages

CenterPoint Energy – Texas Coast Division	10007	Cost of Service Adjustment, CWC, ADIT, Incentive Compensation, Pension, Meter Reading, Customer Records and Collection, Investor Relations/Investor Services
CenterPoint Energy – Texas Coast Division	10097	Pension, Severance Expense
Energas Company	5793	Depreciation
Energas Company v. Westar Transmissions Company	5168 & 4892 Cons.	Cost of Service, Refunds, Contracts, Depreciation
Energas Company	8205	Cost of Service, Rate Base, Depreciation, Affiliate Transactions, Sale/Leaseback, Losses, Income Taxes
Energas Company	9002-9135	Depreciation, Pension, Cash Working Capital, OPEB, Rate Design
Lone Star Gas Company	8664	Cash Working Capital, Depreciation Expense, Gain on Sale of Plant, OPEB, Rate Case Expenses
Rio Grande Valley Gas Company	7604	Depreciation
Southern Union Gas Company	2738, 2958, 3002, 3018, 3019 Cons.	Cost of Service, Rate Design, Depreciation
Southern Union Gas Company	6968 Interim & Cons.	Affiliate Transactions, Rate Base, Income Taxes, Revenues, Cost of Service, Conservation, Depreciation
Southern Union Gas Company	8033 Consolidated	Acquisition Adjustment, Depreciation, Excess Reserve, Distribution Plant, Cost of Gas Clause, Rate Case Expenses
Southern Union Gas Company	8878	Depreciation, Cash Working Capital, Gain on Sale of Building, Rate Case Expenses, Rate Design
Texas Gas Service Company	9988 & 9992 Cons.	Cash Working Capital, Post Test Year Plant, ADFIT, Excess Reserve, Depreciation Expense, Amortization of General Plant, Corporate and Division Expenses, Incentive Compensation, Hotel and Meals Expense, Pipeline Integrity Costs
TXU Gas Distribution	9145-9147	Depreciation, Cash Working Capital, Revenues, Gain on Sale of Assets, Clearing Accounts, Over-Recovery of Clearing Accounts, SFAS 106, Wages and Salaries, Merger Costs, Intra System Allocation, Zero Intercept, Customer Weighting Factor, Rate Design
TXU Gas Distribution	9400	Depreciation, Net Salvage, Cash Working Capital, Affiliate Transactions, Software Amortization, Securitization, O&M Expenses, Safety Compliance
TXU Lone Star Pipeline	8976	Depreciation, Net Salvage, Cash Working Capital, ALG vs. ELG

Westar Transmissions Company	5787	Depreciation, Rate Base, Cost of Service, Rate Design, Contract Issues, Revenues, Losses, Income Taxes
TEXAS WATER COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
City of Harlingen-Certificate for Convenience & Necessity	8480C/8485C/8512C	Rate Impact for CCN
City of Round Rock	8599/8600M	Rate Discrimination, Cost of Service
Devers Canal System	8388-M	Affiliate Transactions, O&M Expense, Return, Allocation, Acquisition Adjustment, Retroactive Ratemaking, Rate Case Expenses, Depreciation
Devers Canal System	30102-M	Cost of Service, Rate Base, Ratemaking Principles, Affiliate Transactions
Southern Utilities Company	7371-R	Affiliate Transactions, Cost of Service
Scenic Oaks Water Supply Corporation	8097-G	Affiliate Transactions, Cost of Service, Rate base, Cost of Capital, Rate Design, Depreciation
Sharyland Water Supply vs. United Irrigation District	8293-M	Rate Discrimination, Cost of Service, Rate Case Expenses
Southern Water Corporation	2008-1811-UCR	Cost of Service
Travis County Water Control & Improv. District No. 20		Cost of Service
EL PASO PUBLIC UTILITY REGULATION BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Southern Union Gas Company	1991	Depreciation, Calculation Procedure
Southern Union Gas Company	1997	Depreciation, Calculation Procedure
Southern Union Gas Company	GUD 8878 – 1998	Depreciation, Cash Working Capital, Rate Design, Rate Case Expenses
Texas Gas Services Company	2007	Revenue Requirements
Texas Gas Services Company	2011	Revenue Requirements
UTAH		
UTAH PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
PacifiCorp	98-2035-03	Production Plant Net Salvage, Production Life Span, Interim Additions, Mass Property, Depreciation
Questar	05-057-T01	Conservation Enabling Tariff Adjustment Option and Accounting Orders
Rocky Mountain Power	07-035-13	Depreciation
WYOMING		
WYOMING PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
PacifiCorp	20000-ER-00-162	Rate Parity

MONTANA-DAKOTA UTILITIES, CO.
GAS PLANT DEPRECIATION EXPENSE
PERIOD ENDING DECEMBER 31, 2008

No.	Account Description	Balance 12/31/2008	Net Salvage %	Net Salvage $	Reserve 12/31/2008	Net Depreciable	Remaining Life	Depreciation Accrual	Rate
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
376.1	Mains - Steel	$41,975,049	-30%	$ (12,592,514.84)	$36,466,143	$18,101,421	36.90	$490,553	1.17%
376.2	Mains - Plastic	$63,935,959	-30%	$ (19,180,787.64)	$30,608,794	$52,507,952	47.45	$1,106,595	1.73%
376.3	Mains - Valves	$447,328	-30%	$ (134,198.43)	$257,220	$324,306	26.16	$12,397	2.77%
376.4	Mains - Manholes	$69,919	-30%	$ (20,975.79)	$55,146	$35,749	39.39	$908	1.30%
376.5	Mains - Bridge/River Cx	$19,818	-30%	$ (5,945.41)	$6,023	$19,741	51.95	$380	1.92%
Total 376		$106,448,074		$ (31,934,422.10)	$67,393,326	$70,989,169		$1,610,833	1.51%
380.1	Services - Steel	$7,285,188	-175%	$ (12,749,078.77)	$12,429,968	$7,604,299	13.43	$566,217	7.77%
380.2	Services - Plastic	$42,690,273	-175%	$ (74,707,978.15)	$30,149,319	$87,248,932	29.00	$3,008,584	7.05%
380.3	Farm/Fuel Lines	$248,640	-175%	$ (435,120.32)	$256,290	$427,470	17.96	$23,801	9.57%
Total 380		$50,224,101		$ (87,892,177.24)	$42,835,578	$95,280,701		$3,598,602	7.17%
381	Meters	$55,172,050	-5%	$ (2,758,602.51)	$16,541,851	$41,388,802	24.19	$1,710,988	3.10%
Others	Remaining Accounts	$39,980,869	14%	$ 5,574,093.50	$20,321,636	$14,085,139	13.76	$1,023,825	
Total		$251,825,094		$ (117,011,108.35)	$147,092,391	$221,743,811		$7,944,249	
	MDU Request							$10,224,058	
	MCC Adjustment							$ (2,279,808.16)	

SOURCES AND REFERENCES

Columns (a & d) : MDU Exhibit No.___(EMR-1) pages 2-1 through 2-4.
Columns (b & f) : See Mr. Pous' testimony for adjustments.
Column (c) : Column (b) times Columun (a).
Column (e) : Column (a) less Columun (c) less Column (d).
Column (g) : Column (e) divided by Columun (f).
Column (h) : Column (g) divided by Columun (a).

MONTANA-DAKOTA UTILITIES, CO.
COMMON PLANT DEPRECIATION EXPENSE
PERIOD ENDING DECEMBER 31, 2008

No.	Account Description	Balance 12/31/2008	Net Salvage %	Net Salvage $	Reserve 12/31/2008	Net Depreciable	Remaining Life	Depreciation Accrual	Depreciation Rate
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
390	Structures & Improvements	$26,865,571	20%	$5,373,114	$11,607,449	$9,885,009	44.76	$220,845	0.82%
Other	Depreciable Plant	$15,928,889	7%	$1,114,766	$10,589,575	$4,224,548	3.32	$1,273,021	7.99%
Total	Depreciable Plant	$42,794,460		$6,487,880	$22,197,024	$14,109,557		$1,493,865	
	MDU Request							$1,877,496	
	MCC Adjustment							$ (383,630.66)	

SOURCES AND REFERENCES

Columns (a & d) : MDU Exhibit No.___(EMR-2) pages 2-1 through 2-4.
Columns (b & f) : See Mr. Pous' testimony for adjustments.
Column (c) : Column (b) times Columun (a).
Column (e) : Column (a) less Columun (c) less Column (d).
Column (g) : Column (e) divided by Columun (f).
Column (h) : Column (g) divided by Columun (a).

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED JANUARY 11, 2013
DOCKET NO. D2012.9.100

MCC-150 RE: ACCOUNT 376
WITNESS: ROBINSON

Please provide a detailed narrative explaining specifically how the 47R4 life-curve combination was selected for Accounts 376.1 and 376.2 – Mains Steel and Plastic, respectively. To the extent SPR results were relied upon, provide all ranking criteria for selected curves, as well as full justification for which band analysis was relied upon, and why the results of other bands were not relied on.

Response:

Please see Attachment A for a general ranking of statistical best fit curve for varying experience bands. The output of the SPR analysis is not maintained in paper copy or other format. The databases and study software are electronic and the analysis was utilized to run numerous band analysis in real time during the course of completing the study. Plot outputs are provided in the depreciation study report for the service life parameters that were estimated for each of the property groups.

Please see Response No. MCC-135 for a complete copy of the historic depreciation database. The SPR is one additional tool of various items that are reviewed to identify the applicable service life for each of the applicable property groups.

Montana-Dakota Utilities Company
Gas Division
376.00 MAINS

Summary of Simulated Curve Fitting Results
5 Year Band

Experience Band	Curve Dispersion	Ave. Serv. Life	Least Sum Of Square	Conformance Index	Index of Variation	Ret. Exp. Index
1916 - 2008	O3	160.6	7.818200E+13	28.38	35.23	43.37
2004 - 2008	O3	191.5	4.643100E+11	313.9	3.19	37.33
1999 - 2003	O3	172.9	5.993700E+11	227.5	4.4	40.78
1994 - 1998	O3	150.9	4.652100E+11	229.4	4.36	45.62
1989 - 1993	O4	185.3	3.044900E+11	216.8	4.61	48.26
1984 - 1988	S.5	61.2	2.596900E+11	197.7	5.06	79.35
1979 - 1983	O4	166.6	1.917100E+11	185.2	5.4	51.84
1974 - 1978	O4	140.6	1.526200E+11	163.1	6.13	57.46
1969 - 1973	R4	28.8	1.331000E+10	446.7	2.24	100
1964 - 1968	O4	114.5	2.242100E+09	784.2	1.28	63.88
1959 - 1963	R2.5	34.9	1.655100E+10	215.2	4.65	100
1954 - 1958	R2.5	36.3	7.171700E+08	699.5	1.43	100
1949 - 1953	S6	31.8	1.322600E+08	954.9	1.05	100

Simulated Plant Record Analysis

SPS 2012 Engagment

Account: 367

Version: SPS 2012 Engagement SPR Data

Method: Simulated Balances

No. of Test Points: 20 Interval: 0 Observation Band: 1992 - 2011

Dispersion	Avg Service Life	Sum of Squared Differences	Index of Variation	Conformance Index	Retirement Experience Index
R1	51.8	5.45E+11	9.2278	108.37	93.52
S-.5	59.1	5.90E+11	9.6069	104.09	76.86
R0.5	60.6	5.93E+11	9.6319	103.82	75.56
R1.5	46.8	6.09E+11	9.7614	102.44	99.35
L0	66.4	6.42E+11	10.0177	99.82	70.38
L0.5	58.2	6.74E+11	10.2656	97.41	79.58
S0	50.6	7.25E+11	10.6465	93.93	92.88
R2	42.7	9.37E+11	12.1014	82.64	100.00
S0.5	46.6	9.42E+11	12.1338	82.41	98.68
L1	52.1	9.61E+11	12.2550	81.60	87.76
L1.5	48.0	1.30E+12	14.2543	70.15	93.38
R2.5	40.6	1.42E+12	14.8931	67.15	100.00
S1	43.9	1.47E+12	15.1654	65.94	100.00
S1.5	41.5	2.03E+12	17.8121	56.14	100.00
L2	44.7	2.21E+12	18.5683	53.86	97.19
R3	38.4	2.34E+12	19.1200	52.30	100.00
L2.5	42.0	2.86E+12	21.1280	47.33	99.16
S2	39.6	3.05E+12	21.8237	45.82	100.00
S2.5	38.7	3.88E+12	24.6415	40.58	100.00
L3	40.2	4.21E+12	25.6534	38.98	99.95
R4	36.3	4.83E+12	27.4874	36.38	100.00
S3	37.7	5.22E+12	28.5606	35.01	100.00
L4	37.0	6.50E+12	31.8755	31.37	100.00
S4	36.0	8.36E+12	36.1543	27.66	100.00
R5	35.4	9.34E+12	38.2023	26.18	100.00
L5	35.9	9.54E+12	38.6204	25.89	100.00
S5	35.1	1.12E+13	41.8417	23.90	100.00
S6	34.9	1.30E+13	45.1656	22.14	100.00
SQ	38.0	3.32E+13	72.0009	13.89	100.00