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

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

January 14, 2013

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

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

Dear Ms. Whitney:

Enclosed please find Montana-Dakota Utilities Co.'s response to the Montana Public Service Commission data request dated December 19, 2012. Responses to the following requests are attached:

PSC-002	PSC-008
PSC-004	PSC-009
PSC-005	PSC-010
PSC-006	PSC-011
PSC-007	PSC-013

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachments
cc: Service List

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-002

Regarding: General Operations
Witness: n/a

a. **Please provide an electronic copy of Schedule L-2, with the addition of the corresponding FERC account number for each line item on the Schedule. The requested account numbers are in reference to FERC's Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. Please clearly identify each line item with the corresponding account number. Please also leave all links and formulas intact.**

Response:

a. Please see the enclosed CD for the file name PSC-002 Stmt L.CCOS.xlsx tab Embedded CCOS-Details. The FERC account number is listed following the line item name.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-004

Regarding: Natural gas costs
Witness: various

a. Please provide MDU's 10-year projection of natural gas supply costs.

b. Please identify any natural gas producing assets MDU plans to acquire in the next I 0 years, including additional landfill projects.

c. Ms. Aberle includes $0.06/dkt from the Billings Landfill Project as part of the marginal cost of gas in MDU's marginal cost study. Does MDU believe that $0.06 per dkt is an accurate representation of the marginal cost of natural gas? Does MDU believe the $0.06 represents an energy cost or a capacity cost?

Response:

a. Please see Attachment A.

b. Montana-Dakota does not have plans to acquire additional gas producing assets at this time but will continue to look for opportunities in the market.

c. The $.06 per dk is the marginal non-gas production cost associated with the Billings landfill. The cost represents an energy related cost.

Estimated MDU commodity prices 2013 - 2022 (January 8, 2013)

	EIA-AEO Early Outlook H Hub Dec 12 EIA	Bentek Forward Curve 12/11/12	NYMEX Futures Avg Dec-12	HENRY HUB AVERAGE	Ventura Estimates	Henry/CIG Differential	Average CIG Price	Average MDU Price Avg. of Prices	Average CIG Price based on EIA	MDU prices based on avg of estimates
2013	3.25	$3.46	$3.59	$3.43	$3.43	$0.20	$3.23	$3.30	$3.63	$3.30
2014	3.12	3.78	4.02	3.64	3.64	0.20	3.44	3.51	3.84	3.51
2015	3.12	4.13	4.21	3.82	3.82	0.20	3.62	3.69	4.02	3.69
2016	3.57	4.43	4.34	4.11	4.11	0.20	3.91	3.98	4.31	3.98
2017	3.70	4.48	4.47	4.21	4.21	0.20	4.01	4.08	4.41	4.08
2018	3.96	4.61	4.60	4.39	4.39	0.20	4.19	4.26	4.59	4.26
2019	4.05	4.75	4.74	4.51	4.51	0.20	4.31	4.38	4.71	4.38
2020	4.13	4.89	4.88	4.63	4.63	0.20	4.43	4.50	4.83	4.50
2021	4.26	5.04	5.03	4.77	4.77	0.20	4.57	4.64	4.97	4.64
2022	4.48	5.19	5.18	4.95	4.95	0.20	4.75	4.82	5.15	4.82

Assuming MDU purchases 65% of its gas at CIG index and 35% at Ventura index. Assuming Ventura differential to Henry Hub is zero.

Escalated Nymex prices by 3% annually for 2016-2022

Escalated Bentek prices by 3% annually for 2016-2022

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-005

Regarding: Mains
Witness: Aberle

a. **Please explain how MDU calculated the cost of mains on Page 13 of Exhibit No._(TAA-3) (Line 19 in the electronic form of Exhibit No._(TAA-3)). Please provide any receipts or supporting work papers that were used to derive the cost.**

b. **Are all residential customers served off of the same sized main (in diameter)? Does MDU have any customer class in which all customers are served off of the same sized main? If so which classes?**

c. **In its most recent electric rate case (docket no. D2010.8.82), MDU proposed to use an average and excess demand allocation method to distribute transmission-related costs between both the demand and energy components of service, in both its marginal and embedded cost of service studies.[1] Would it be reasonable to use the average and excess demand allocation method to allocate distribution mains in this case? If not, please explain why.**

Response:

a. Please see Attachment A for the workpaper underlying the derivation of the cost of mains based on the average installed costs for the twelve month period ending 12-31-2011. The information was derived from average main extension lengths by customer class derived from the GIS mapping system for the prior year (2011) projects.

b. No, Residential customers are typically served off of a 2 inch or 4 inch pipe size for the main, and Montana-Dakota does not have a customer class in which all customers are served off the same sized pipe for the main. Montana-Dakota's current standards would install a minimum 2" pipe size for the main.

c. Distribution mains function in a fashion similar to distribution electric lines that were allocated on a factor based on customers and the non-coincident peak for each class in the electric case. In the Company's opinion it would not be reasonable to use an average and excess demand allocation for distribution mains.

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1 P. 14 Heidell direct testimony and P. 5 Aberle direct testimony in docket no. D2010.8.82

	Residential Rate 60	Firm General Rates 70/72	Small Interruptible Rates 71/81	Large Interruptible Rates 82/85
Marginal Customer Costs (2011 Dollars)				
Main Extension - when required	$1,036.69	$1,555.56	$1,555.56	$4,470.41
Company Owned Service Line	$549.10	$965.00	$965.00	$4,183.40
Meter & Regulator	$145.29	$1,031.51	$5,587.40	$14,420.17
Total Investment	**$1,731.08**	**$3,552.07**	**$8,107.96**	**$23,073.98**

Main

	Avg Length (Ft.)	Main Size	Cost/ft.(2011)	Cost/Extension	Inflation 1.044
Residential (Rate 60)	100	2"	$9.93	$993	$1,036.69
Firm Commercial (Rate 70)	150	2"	$9.93	$1,490	$1,555.56
Small Interruptible (Rate 71/81)	150	2"	$9.93	$1,490	$1,555.56
Large Interruptible (Rate 82/85)	300	4"	$14.27	$4,282	$4,470.41

Service Line Complete

Service Line Complete (Stub and Service line)

Montana

	Avg Length - Ft.	Cost/ft.	Cost/S.L.
Residential Service Line Cost	85	$6.46	$549.10
Firm Commercial Service Line Cost	125	$7.72	$965.00
Small Interruptible Service Line Cost	125	$7.72	$965.00
Large Interruptible Service Line Cost	260	$16.09	$4,183.40

Meter & Regulator

	Meter & Reg	Installation cost	Total
Residential (Group 1)	61	85	$145.29
Firm Commercial (Group 2)	728	303	$1,031.51
Small Interruptible (Group 3)	4,022	1,565	$5,587.40
Large Interruptible (Specific situation)	9,264	5,156	$14,420.17

Response No. PSC-005a
Attachment A
Page 1 of 1

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-006

Regarding: Calculation of allocation factors
Witness: Aberle

a. **Please describe how MDU measures 'Peak Day@ Distribution' (allocation factor 5) for each of its customer classes. If some or all members of a particular customer class do not have meters please fully explain how MDU measures use for that class.**

b. **Please provide the supporting information and/or work papers MDU used to derive its cost for the 'average installed meter cost' used in its calculation of allocation factor 10. Please include the number of meters installed and the cost for each of those installed meters.**

c. **On page 7 of Exhibit No._(TAA-3), it appears only 8 of the 9 distribution plant additions were included in the calculation of 'Demand-Related Distribution Investment per Additional Mcfd of Distribution Capacity'. Was this intentional? If so, please explain.**

d. **Regarding the distribution plant additions referred to in part (c), please describe the nature of each project including all causal factors that contributed to the Company's decision to undertake each project and the criteria for determining the design capacity for each project.**

e. **Please estimate the cost savings for each of the distribution plant additions referred to in part (c) if the design capacities were reduced by 50%.**

Response:

a. Montana-Dakota's peak day related factors (Factor Nos. 2 and 5) are not based on measured peaks by customer class. The total peak day throughput based on border station deliveries is allocated to each customer class based on the use per peak day determined in the regression analysis discussed in Response No. PSC-007. The determination of the factors is provided in the Statement and Exhibit Workpapers, Statement L, page 23. An error has been discovered in the original calendar year peak day deliveries used to derive Factors 2 and 5. Please see Attachment A for the revised Allocation Factor No. 2, 1-Day Peak and Allocation Factor No. 5, Peak Day @ Distribution. A revised embedded class cost of service study (Statement L) is provided in electronic format on the enclosed CD.

b. Please see Statement and Exhibit workpapers, Statement L, Pages 26-27.

c. No, this is an error. Please see Attachment B for the revised Pages 1, 2, 6 & 7 of Exhibit No. (TAA-3) reflecting the correction to the marginal demand-related distribution investment per Mcfd.

d. Following is a description of each project utilized in the determination of the Distribution Plant Additions, Page 7 of Exhibit No. __ (TAA-3)

- Project 1 – Residential subdivision to serve 57 lots at developer's request. Approximately 8,000' of main which included 740' of 4" pipe for the main. Throughout the interior of the subdivision, smaller pipe was installed but the 4" pipe was utilized for less than 10% of this project, which allowed the Company to continue the trunk line for future development. If 2" pipe had been installed rather than 4"pipe, the savings would come from material only, since the labor and equipment costs would be very similar regardless of pipe size. Difference in cost would have been approximately $1,300, or 8.6%.
- Project 2 - 42 lot residential subdivision, installed at developer's request. The Company utilized 4", 2" and 1 ¼" pipe throughout project. Since the subdivision is in extreme west end of the distribution system, a larger trunk line was required to serve future customers in the area and to eventually provide a loop. The loop provides protection to customers in the event of a damaged line and helps with lower pressure areas. If 2" pipe had been installed in place of the 4"pipe, approximate difference in cost of $4,800, or 36%.
- Project 3 – 33 lot residential subdivision, installed at developer's request. Installed 4" pipe along the east edge only, allowing the Company to continue a feeder line in the area. 1 ¼" pipe installed within the subdivision. If 2" pipe had been installed in place of the 4" pipe, approximate difference of $2,400 or 12% of the project.
- Project 4 - 38 lot residential subdivision, installed at developer's request. This subdivision is in the extreme north east portion of the distribution system and the larger pipe was installed along the perimeter only, installing smaller pipe within the subdivision. There is a large industrial area to the east of this area making the installation of larger pipe prudent for future development. If 2" pipe has been installed versus 4" and 6" pipe approximate cost difference of $13,700 or 19% of the project.
- Project 5 – 96 lots within this phase of the residential subdivision. This subdivision is located in the extreme NW portion of the distribution system. 4100' of 4" main required to reach the subdivision. This pipe size allowed for future expansion throughout

the subdivision. If 2" pipe had been installed rather than the 4" pipe, approximate cost difference of $12,400 or 47%.

- Project 6 – 45 lot residential subdivision. Installed 4" main along north edge only, to continue a system trunkline rather than 6" pipe as depicted in the study resulting in incremental capacity of 530 Mcfd rather than 1,693 Mcfd. If 2" pipe had been installed rather than the 4"pipe, approximate cost difference of $4,932 or 18%.
- Project 7 – This was a reinforcement project initiated by Montana-Dakota. For design purposes, a 10% pressure drop is deemed acceptable. In the winter months, pressure drops on the west end of Billings were exceeding the design pressure drop calling for this reinforcement project. Installing the 4" main in key areas within the distribution system allowed the Company to provide a loop to the system, which alleviates the pressure drops. In case of damage to the system, the looping project allows the Company to improve reliability by providing two-way feed.
- Project 8 – The State of Montana was completing a road project which required that Montana-Dakota relocate existing main. The Company used this opportunity to replace the main with a larger size due to the growth on the west side of Billings. This 6" line comes immediately out of the West Border Station and is the primary station feeding the town of Billings. Installing the 6" main at the time of the road project was the most economical, allowing the Company to avoid permit fees, resurfacing costs, traffic control, etc.
- Project 9 – This new border station was required because pressures in the area were low enough that in the previous winter during extreme cold, customers within a subdivision momentarily lost service. Adding the station alleviated pressure dips in the south east portion of the subdivision.

e. The cost differential to install smaller size pipe is noted in Response No. PSC-006 d. above where applicable. The cost to provide the capacity in the future would be much higher because parallel facilities would need to be installed just to provide the incremental capacity afforded by upsizing the pipe at this time.

Factor No.	Description	Total Montana	Residential Demand	Small Firm General Demand	Large Firm General Demand	Small Interruptible Demand	Large Interruptible Demand
		93,245	48,732	10,098	20,435	2,479	11,501
2	1-Day Peak	100.000000%	52.262320%	10.829535%	21.915384%	2.658588%	12.334173%
	Revised	103,428	54,992	11,396	23,060	2,479	11,501
2	1-Day Peak	100.000000%	53.169355%	11.018293%	22.295703%	2.396836%	11.119813%
		85,504	48,225	10,068	20,290	2,007	4,914
5	Peak Day @ Distribution	100.000000%	56.400870%	11.774888%	23.729884%	2.347259%	5.747100%
	Revised	95,687	54,485	11,366	22,915	2,007	4,914
5	Peak Day @ Distribution	100.000000%	56.940859%	11.878312%	23.947872%	2.097464%	5.135494%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

Marginal Cost	Total	Residential Rate 60	Firm General Rates 70/72 Small Meters	Firm General Rates 70/72 Large Meters	Small Interruptible Rate 71/81	Large Interruptible Rate 82/85
(1)	(2)	(3)	(3)	(4)	(5)	(6)
I - Marginal Cost-Based Revenues						
Marginal Costs						
Commodity Cost ($/Dk) 1/		$3.917	$3.917	$3.917	$2.938	$2.938
Demand Cost ($/MCFD) 2/						
Distribution Level Service 2/		$209.11	$141.04	$25.04	$7.11	$3.05
Customer Cost ($/Month) 2/		$15.26	$22.97	$69.50	$230.08	$418.60
Billing Determinants 3/						
Dk Sales	10,129,873	6,097,461	1,119,203	2,694,623	218,586	0
Dk Transportation	4,884,226	0	0	0	686,293	4,197,933
Total Dk Throughput	15,014,099	6,097,461	1,119,203	2,694,623	904,879	4,197,933
Dk Throughput at Distribution	12,268,927	6,012,077	1,097,011	2,633,666	732,540	1,793,633
Peak Demand at Dist. (Mcfd)	85,504	48,225	10,068	20,290	2,007	4,914
Average No. of Customers	78,910	70,161	6,547	2,153	44	5
Average No. of Bills	946,920	841,932	78,564	25,836	528	60
Marginal Cost-Based Revenues						
Commodity (Sales Gas)	39,464,717	23,883,755	4,383,918	10,554,838	642,206	0
Demand (Distribution Level)	12,041,641	10,084,330	1,419,991	508,062	14,270	14,988
Customer	16,594,697	12,847,882	1,804,615	1,795,602	121,482	25,116
Total	$68,101,055	$46,815,967	$7,608,524	$12,858,502	$777,958	$40,104
II - Final Proposed Revenue Requirement 4/	$62,794,604					
III - Adjustment Factor	0.92207975					
IV - Revenue Requirements						
Proportioned to classes	$62,794,603	$43,168,055	$7,015,666	$11,856,564	$717,339	$36,979
Less Miscellaneous Revenue 5/	$416,112	$280,482	$37,585	$81,820	$7,553	$8,672
Net Revenue Requirement	$62,378,491	$42,887,573	$6,978,081	$11,774,744	$709,786	$28,307
V - Operating Revenue Before Increase 5/	$58,923,014	$35,729,916	$6,648,114	$14,608,669	$1,387,511	$548,804
VI - Required Increase	$3,455,477	$7,157,657	$329,967	($2,833,925)	($677,725)	($520,497)
VII Percentage Increase	5.86%	20.03%	4.96%	-19.40%	-48.84%	-94.84%

1/ Exhibit No. __(TAA-3) page 2
2/ Exhibit No. __(TAA-3) pages 6-12.
3/ Rule 38.5.164, Statement H, page 3.
4/ Rule 38.5.175, page 7.
5/ Rule 38.5.176, Schedule L-1, page 4

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

SUMMARY OF MARGINAL COSTS BY CUSTOMER CLASS

	Customer Class				
Marginal Cost	Residential Rate 60	Firm General Rates 70/72 Small Meters	Firm General Rates 70/72 Large Meters	Small Interruptible Rate 71/81	Large Interruptible Rate 82/85
(1)	(2)	(3)	(4)	(5)	(6)
Commodity Cost ($/Dk) 1/	$3.917	$3.917	$3.917	$2.938	$2.938
Demand Cost ($/MCFD) 2/ Distribution Level Service	$209.11	$141.04	$25.04	$7.11	$3.05
Customer Cost ($/Customer/Month) 3/	$15.26	$22.97	$69.50	$230.08	$418.60

1/ Exhibit No. __ (TAA-3), page 3.
2/ Exhibit No. __ (TAA-3), page 6.
3/ Exhibit No. __ (TAA-3), pages 8-12.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

ANNUALIZATION OF DISTRIBUTION DEMAND-RELATED MARGINAL COSTS

Line No.	Description	Rate 60	Rate 70 < 500 cu ft	Rate 70 > 500 cu ft	Rates 71/81	Rates 85/82
1	Distribution Demand-Related Marginal Cost ($/Mcfd) 1/	$1,557.16	$1,050.31	$186.57	$52.94	$22.78
2	General and Common Plant Allocation (Line 1 x 27.26%) 2/	424.48	286.31	50.86	14.43	6.21
3	Marginal Cost Including General Plant	1,981.64	1,336.62	237.43	67.37	28.99
4	Annual Levelized Real Carrying Charge (Percent of Investment) 3/	8.655%	8.655%	8.655%	8.655%	8.655%
5	Annual Levelized Amount (Line 3 x Line 4)	171.51	115.68	20.55	5.83	2.51
6	Demand-Related Operation & Maintenance Expense (Line 3 x .78%) 4/	15.46	10.43	1.85	0.53	0.23
7	Demand-Related Administrative & General Allocation (Line 3 x 0.41%) 5/	8.12	5.48	0.97	0.28	0.12
8	Annualized Investment Adjusted for General Plant, O&M and A&G Expenses (Line 5 + Line 6 + Line 7)	195.09	131.59	23.37	6.64	2.86
	Taxes Other Than Income Taxes (Excl. Revenue-Related)					
9	Property Taxes (Line 3 x 0.60%) 6/	11.89	8.02	1.42	0.40	0.17
10	Payroll Taxes ((Line 6 + Line 7) x 4.15%) 6/	0.98	0.66	0.12	0.03	0.01
11	Sub-Total Taxes Other	12.87	8.68	1.54	0.43	0.18
	Working Capital Requirement					
12	Materials and Supplies (Line 3 x .14%) 2/	2.77	1.87	0.33	0.09	0.04
13	Prepayments (Line 3 x 0.01%) 2/	0.20	0.13	0.02	0.01	0
14	Total Working Capital	2.97	2.00	0.35	0.10	0.04
15	Required Return on Working Capital 7/	12.197%	12.197%	12.197%	12.197%	12.197%
16	Working Capital Amount (Line 14 x Line 15)	0.36	0.24	0.04	0.01	0
17	Sub-Total (Line 8 + Line 11 + Line 16)	208.32	140.51	24.95	7.08	3.04
18	Revenue-Related Taxes (Line 17 x 0.38%) 6/	0.79	0.53	0.09	0.03	0.01
19	Total Demand-Related Marginal Cost of Distribution	$209.11	$141.04	$25.04	$7.11	$3.05

1/ Exhibit No. __(TAA-3), page 7 and page 13.
2/ Exhibit No. __(TAA-3), page 14.
3/ Exhibit No. __(TAA-3), page 16.
4/ Exhibit No. __(TAA-3), page 17.
5/ Exhibit No. __(TAA-3), page 24.
6/ Exhibit No. __(TAA-3), page 26.
7/ Exhibit No. __(TAA-3), page 15.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
MARGINAL COST STUDY

MARGINAL DEMAND-RELATED DISTRIBUTION INVESTMENT

Montana Demand-Related
Distribution Plant Additions

Project Number	Project Year	Incremental Capacity (Mcfd)	Investment in Gas Distribution System	Restated in 1/1/14 Dollars 1/
(1)	(2)	(3)	(4)	(5)
1	2011	415	$15,861	$16,180
2	2011	638	13,160	13,424
3	2011	800	19,620	20,014
4	2011	971	70,000	71,406
5	2011	1,613	26,350	26,879
6	2011	1,693	28,000	28,562
7	2011	3,000	145,000	147,912
8	2011	4,000	65,000	66,305
9	2011	12,000	64,000	65,285
	Total	25,130	$446,991	$455,967

Demand-Related Distribution Investment per Additional Mcfd of Distribution Capacity	$18.14

1/ Plant additions in Column (4) are restated in 1/1/14 dollars in Column (5) using the Producer Price Index for Metals and Metal Products (weighted 50%) and the Producer Price Index for Unit Labor Costs - Non Farm (weighted 50%).

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-007

Regarding: Calculation of allocation factors 2 and 5
Witness: Aberle

a. **Please provide, in electronic format, the complete regression analysis MDU used to calculate allocation factors 2 and 5. Please include all underlying data, supporting work papers, and documentation. Please also explain the method MDU used to determine weather-normalized volumes.**

b. **Please provide a brief explanation of the method used to calculate the 'Use per Degree Day per customer' and 'Daily Baseload per customer' values.**

c. **Over what period of time did MDU inspect to determine the annual peak day is January 31, 2011?**

d. **Please provide the daily load figures for each of MDU's customer classes over the time period that MDU inspected when determining the annual peak day.**

e. **Please explain how MDU measures the daily load for each of its customer classes. If sampling is used to estimate any class load, please fully describe the sampling process.**

Response:

a. Please see response PSC-006 a. and enclosed CD file named PSC-007 regarding the development of Factors 2 and 5. The normalized volumes were based on linear regression models developed for each class with weather sensitive volumes. The direct or linear relationship between a respective service class' gas use (a dependent variable) and actual heating degree days (an independent variable) was used to calculate a use per customer that reflects this historic relationship. The statistical functions used by the Company in its regression models formulated a baseload use (or constant) per customer, as well as a dekatherm use per degree day. The baseload (or non-temperature sensitive use) was calculated using the intercept function. The intercept function identifies the point at which a line will intersect the y-axis (or the dependent variable axis, i.e. gas use), when the independent variable (i.e. degree days) is 0 by using the two data sets' history. In other words, the intercept function identifies the use that would still exist if the average temperature was equal to or greater than 60 degrees. Please see the Statement and Exhibit Workpapers, Statement H, page 22. The Dk per Degree Days was calculated using the Slope function. The Slope function identifies the

linear trend of use to degree days. The result is the level of Dk use associated with one degree day. In other words, the slope function identifies the class or customer use that is affected by weather. The normalized volumes for the twelve months ended December 31, 2011 were developed, by applying the actual customer levels and normal degree days for each month of 2011 to this baseload and use per degree day.

b. Please see Response No. PSC-007 a.

c. Montana-Dakota reviewed the daily peak volumes for the period of January 1, 2011 through December 31, 2011.

d. Daily load figures are not available by class by day.

e. Please see Response No. PSC-006 a.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-008

Regarding: Natural gas load forecast
Witness: Aberle

Was the natural gas load forecast used by MDU in this docket calculated assuming MDU's current rates for natural gas? Please provide a detailed description of the method MDU uses to forecast its natural gas load.

Response:

Montana-Dakota did not utilize a gas load forecast in this docket. The actual consumption recorded for the twelve month period ending December 31, 2011 was adjusted to reflect normal weather, as described in Response No. PSC-007a, and further adjusted to reflect the annualization of customers to the December 2011 level. Non-weather sensitive interruptible throughput was based on a customer by customer analysis to determine adjustments necessary to normalize actual calendar year deliveries.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
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PSC-009

Regarding: Rate design
Witness: Aberle

a. **Please explain why MDU is requesting a basic service charge which uses a daily rate structure instead of a monthly rate structure.**

b. **If the PSC accepted MDU's proposal to use a daily rate to calculate MDU's basic service charge, would a customer bill also display the basic service charge as a total for the entire month?**

c. **Does MDU offer a budget billing option to its customers?**

d. **MDU's embedded cost of service study indicates that MDU is under-earning in both the demand and customer components of service for the residential class. Why is MDU proposing to increase only the basic service charge, which appears to be the basis for revenues of the customer component of service, in its proposed rate design? Should both the demand and customer components be moved to closer to their respective cost of service?**

Response:

a. The Basic Service Charge is proposed to be collected on a daily basis in order to avoid prorating the monthly charge when customers are in service less than 30 days, on average, or when a billing period is less than or more than the defined normal.

b. The number of billing days, the daily rate and the total calculated amount of the basic service charge would be displayed on the customer's bill.

c. Yes, Montana-Dakota offers a Balanced Billing program for residential and firm general service customers.

d. Montana-Dakota does not measure demand for gas service customers and the existing rate schedules do not contain a demand price component. Demand costs are effectively recovered through the energy charge to the extent the Basic Service Charge does reflect all identified customer costs.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-010

Regarding: Statement L, meter groups
Witness: Aberle

a. **The hard copy of Statement L attached to Ms. Aberle's testimony, p. L-27, calculates average weighted meter costs. Please clarify whether the costs shown on this page include regulator costs.**

b. **Please explain what distinguishes the meter groups for the residential class and what the numbered sizes refer to. For example, does the 250 size for Group 1 imply that the meter is rated at 250 cubic feet per hour?**

c. **Are the 650 size Group 1 meters and the Group 2 large diameter meters master meters that serve multiple residential units? If not, what accounts for the need for these larger meters?**

d. **Please provide information supporting the meter costs and expected economic lives.**

Response:

a. The average meter cost does include the cost for the regulator.

b. Montana-Dakota places a meter size into groups based on meter types and the capitalized cost of the meter including the installation cost for the meter type. The 250 size meters imply that 250 cubic feet per hour is the rating of the meter.

c. The larger 650 size Group 1 and 2 serve multiple residential units or can also serve a larger single family home. The on demand waters heaters can also contribute to the need for the larger size meter for a residential customer.

d. Please see Attachment A for the average meter costs workpaper supporting the Statement and Exhibit Workpapers, Statement L, page 27 average meters costs column. Expected life is a minimum of 30 years or less depending if there is a problem with accuracy or performance. Average life for residential meter is about 40 years and commercial meters about 45 years.

GROUP 1 METER INSTALLATION COSTS

Installation Cost for Residential Meter (group 1)

	load	hrs	rate	total
Meter Labor	1.47	0.4	$ 33.36	$13.34
Meter Test	1.47	0.083	$ 29.32	$2.43
Mileage	1	3	$ 0.70	$2.10
		Meter installation cost		$17.88

Installation Cost for Meter Bar

	load	hrs	rate	total
Meter Bar Labor	1.47	0.5	$ 33.36	$16.68
Mileage	1	3	$ 0.70	$2.10
		Meter installation cost		$18.78

Installation Cost for Regulator

	load	hrs	rate	total
Regulator Labor	1.47	0.4	$ 33.36	$13.34
Mileage	1	3	$ 0.70	$2.10
		Meter installation cost		$15.44

Rate 60/70
$217.80

Install Cost of ERT 3.25

Regular Bar Meter Set Installed

Meter Bar	$	45.66
Meter	$	61.34
Regulator	$	14.95
ERT		$40.50
Total		**$217.80**

Bar w/ Bend Adapter Installed

Meter Bar	$	40.00
Meter	$	58.00
Adaptor	$	48.00
Regulator	$	15.00
Total		**$213.10**

Rate 60/70
$305.93

Small Commercial Meter Set With Fittings

Meter AC 425	1	1	$	156.16	$156.16
ERT, Res	1	1	$	40.50	$40.50
Swivels 45 LT	1	2	$	3.44	$6.88
Regulator, Res.	1	1	$	14.95	$14.95
small fittings		7	$	1.00	$7.00
Labor	1.47	1.5		$33.36	$73.45
			Total		$298.94
		Less meter and regulator			$171.11
Meter test	1.47	0.083	$	30.63	$3.73
		ERT installation cost			3.25

Group 2 Meter installation Cost

Small Commercial Meter Set With Fittings

ERT, res	1	1	$	40.50	$40.50			
Meter AC 630	1	1	$	420.00	$420.00			
Swivels 45 LT	1	2	$	3.44	$6.88			
Regulator 243-8	1	1	$	169.08	$169.08	81	$723.90	$ 61,512.66
small fittings		7	$	1.00	$7.00			
Labor	1.47	1.5	$	33.36	$73.45			
			Total		$716.91			
		Less meter and regulator			$589.08			
Meter test	1.47	0.083	$	30.63	$3.73			
		ERT installation cost			$3.25			

Small Commercial Meter Set With Fittings

ERT, Com	1	1	$	68.50	$68.50			
Meter AL 800/1000/1600	1	1	$	736.28	$736.28			
Swivels	1	2	$	3.44	$6.88			
Regulator S 302	1	1	$	204.60	$204.60			
Ell 2" Screw		3	$	5.00	$15.00			
Nipples(small fittings)		3	$	1.00	$3.00			
Tee 2x1/2x2		1	$	7.00	$7.00	100	$1,130.45	$ 113,044.55
Small fittings		7	$	1.00	$7.00			
Labor	1.47	1.5	$	33.36	$73.45			
			Total		$1,121.71			
		Less meter and regulator			$940.88			
Meter test	1.47	0.083	$	30.63	$3.73			
		ERT installation cost			$5.00			

Small Commercial Rotary Meter Set

ERT, Res	1	1	$	40.50	$40.50			
Meter 2M\3M TC	1	1	$	1,235.00	$1,235.00			
Petes Plugs	1	4	$	5.50	$22.00			
Regulator S202\243-12	1	1	$	254.60	$254.60			
Valves 2" npt bypass		2	$	54.75	$109.50			
Valves 2" flange		1	$	152.41	$152.41			
Flanges 2"		8	$	18.49	$147.92			
Strainer	1	1	$	85.23	$85.23			
Small fittings		7	$	1.00	$7.00			
Weld ells 3"		3	$	18.38	$55.14			
Reducer 3" x 2"		1	$	88.00	$88.00			
Pipe 2"		6	$	7.70	$46.20			
Welding Supplies		14	$	3.41	$47.74	10	$2,965.85	$ 29,658.52
Labor	1.47	7		$30.63	$314.73			
Welder	1.47	7	$	33.08	$339.91			
			Total		$2,945.88	191	total	$ 204,215.73
		Less meter and regulator			$1,489.60			**Rate 70**
Meter test	1.47	0.333	$	30.63	$14.97			**Intermediate**
		ERT installation cost			$5.00			$ 1,069.19

Small Commercial Rotary Meter Set With Corrector

ERT, Com Remote	1	1	$	74.00	$74.00	
Meter 2M\3M CD	1	1	$	1,043.00	$1,043.00	
Petes plug	1	4	$	5.50	$22.00	
Regulator 301 D	1	1	$	363.64	$363.64	
289 H	1	1	$	182.28	$182.28	
Mini Max AT	1	1	$	1,400.00	$1,400.00	
Valves 2" Flange		1	$	152.41	$152.41	
Valves 2" screw		2	$	54.75	$109.50	
2" Strainer	1	1	$	85.23	$85.23	
Pipe 2"		6	$	7.70	$46.20	
Thermo well	1	1	$	50.00	$50.00	
Weld ells 2"		3	$	12.39	$37.17	
Weld Tee 2" bypass		2	$	29.76	$59.52	
Flange 2"		8	$	18.49	$147.92	
Reducer 3" x 2"		1	$	88.00	$88.00	
Welding supplies		14	$	3.41	$47.74	
Labor	1.47	7	$	30.63	$314.73	**Group 2**
Welder	1.47	7	$	33.08	$339.91	**Rate 71/81**
			Total		$4,563.25	**$4,583.22**
	Less meter and regulator relief & corrector				$2,988.92	
Meter test	1.47	0.333	$	30.63	$14.97	
		ERT installation cost			$5.00	

Group 3 Meter installation Cost

Large Commercial Rotary Meter Set w/ Corrector

ERT, res	1	1	$	40.50	$40.50	
Meter 5M\7M TC	1	1	$	1,729.00	$1,729.00	
Petes Plug	1	4	$	5.50	$22.00	
Regulator 299 H	1	1	$	628.90	$628.90	
Relief 289H	1	1	$	182.28	$182.28	
Mini Max PT	0	0	$	-	$0.00	
Valves 2" FL		1	$	152.41	$152.41	
Valves 3" FL		1	$	256.27	$256.27	
Valves 2" screw		2	$	54.75	$109.50	
3" Strainer	1	1	$	218.36	$218.36	
Pipe 3" x 5'		5	$	9.40	$47.00	
Thermo well	1	0	$	50.00	$0.00	
Weld ells 3"		3	$	18.38	$55.14	
Flange 2"		2	$	18.49	$36.98	
Flanges 3"		4	$	23.49	$93.96	
3" x 2" Reducer		1	$	88.00	$88.00	
Welding supplies		14	$	3.41	$47.74	**Large**
Labor	1.47	9	$	30.63	$404.66	**Group 2**
Welder	1.47	9	$	33.08	$437.02	**Rate 70**
			Total		$4,549.72	**w/ Correcter**
	Less meter and regulator& relief				$2,540.18	**$4,569.69**
Meter test	1.47	0.333	$	30.63	$14.97	
		ERT installation cost			$5.00	

Large Commercial Rotary Meter Set With Corrector

Meter 11M\16M CD	1	1	$	1,820.00	$1,820.00
Petes Plug	1	4	$	5.50	$22.00
Regulator 299 H	1	1	$	628.90	$628.90
Relief 289H	1	1	$	182.28	$182.28
Mini Max AT	1	1	$	1,400.00	$1,400.00
Valves 4" FL		1	$	356.65	$356.65
Valves 2" NPT		2	$	54.75	$109.50
4" Strainer	1	1	$	382.45	$382.45
Pipe 4" x 5'		5	$	14.99	$74.95
Thermo well	1	1	$	50.00	$50.00
Weld ells 4"		3	$	30.23	$90.69
Flange 2"		3	$	18.49	$55.47
Flanges 4"		6	$	29.42	$176.52
4" x 2" Reducer		1	$	115.43	$115.43
Welding supplies		14	$	3.41	$47.74
Labor	1.47	9	$	30.63	$404.66
Weldor	1.47	9	$	33.08	$437.02
				Total	$6,354.26
	Less meter and regulator& relief				$4,031.18
Meter test	1.47	0.333	$	30.63	$14.97
				ERT cost	$74.00
		ERT installation cost			$5.00

Large
Group 3
Rate 70/71/81
w/ Correcter
$6,448.23

Large Industrial Turbine Meter Set (estimate only, wo captures expense)

Meter AAT 18 175#	1	1	$	5,759.61	$5,759.61
Straightning Vanes	1	1	$	218.36	$218.36
Regulator 299 H	1	1	$	628.90	$628.90
Mini AT Turbo Corrector	1	1	$	5,750.00	$5,750.00
Relief Valve 2" 63 EG	1	1	$	1,930.00	$1,930.00
Valves 2" FL	1	4	$	152.41	$609.64
Valves 4" FL fig 143		2	$	356.65	$713.30
Strainer 4" y	1	1	$	382.45	$382.45
Pipe 4"	1	10	$	14.99	$149.90
Thermo well & valve kit	1	1	$	50.00	$50.00
Weld ells 2"		2	$	12.39	$24.78
Weld ells 4"		2	$	30.23	$60.46
Weld Tee 2"		2	$	29.76	$59.52
Weld Tee 4x4x2		2	$	36.42	$72.84
Flange 2"		8	$	18.49	$147.92
Flanges 4"		8	$	29.42	$235.36
4" x 2" Reducer		1	$	115.43	$115.43
Welding supplies		14	$	3.41	$47.74
Labor	1.47	16	$	30.63	$719.39
Welder	1.47	32	$	33.08	$1,553.86
				Total	$19,229.46
	Less meter, regulator, corrector, and relief				$12,329.51
Meter test	1.47	0.333	$	30.63	$14.97

Rate 82/85
w/ Correcter
$19,244.43

Meter Install costs

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-011

Regarding: Large and small interruptible transport customer loads
Witness: Aberle

a. **For each of the large interruptible transport customers shown in the electronic copy of Statement L (provided in data response PSC-00 l), under the tab labeled "MT Dist. Direct Alloc," provide the average daily throughput by month for the last 5 years and the actual daily throughput for 2011.**

b. **Does the inclusion of volumes for the small and large interruptible transport customers in the calculation of the Factor 2 and Factor 5 embedded cost study allocation factors (see the tab labeled "I Day Pk Deliveries Revised") indicate that these customers also purchase some amount of firm sales service? If not, please explain why these peak demand allocation factors include volumes from interruptible customers.**

c. **For the small interruptible transport customers, provide the aggregate average daily throughput by month for the last 5 years and the actual aggregate daily throughput for 2011.**

d. **Provide weighted Montana (seep. L-25 in Statement L attached to Ms. Aberle's testimony) monthly and peak day heating degree day data for the last 15 years.**

e. **Please explain the basis for assigning interruptible customers peak day volumes based on 100% load factors (see the tab labeled "I Day Pk Deliveries Revised").**

Response:

a. Please see the enclosed CD for the file named PSC-011 Transport Throughput.xlsx.

b. Allocating distribution demand costs to small and large interruptible customers based on a 100% load factor is done in order to recognize that while the interruptible customers are not contributing to the peak day demand costs there should be recognition of the demand placed on the system by this class of customers.

c. Please see the enclosed CD for the file name PSC-011 Transport Throughput.xlsx.

d. Please see the enclosed CD for the file name Response No. PSC-011.d, Attachment A, for the Montana weighted peak day degree days for the

period of 2002-2012. Degree day information prior to calendar year 2002 is unavailable.

e. Please see response b. above.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 19, 2012
DOCKET NO. D2012.9.100

PSC-013

Regarding: Rate schedules
Witness: Aberle

a. **Please explain the reason for the reduction in the Rate 71 maximum distribution delivery charge from $.742 per dk to $.734 per dk. Is this reduction tied to either the embedded or marginal cost study?**

b. **What is the reason for the difference in the maximum distribution delivery charges for Rate 71 and Rate 85; is it due to service priorities under interruptible tariff provisions or to other cost of service factors?**

c. **Please provide a brief explanation of the origins of Rate 93 and clarify whether these customers use MDU's distribution system.**

d. **Does the $0.04 per Mcf rate in Rate 93 tie to MDU's embedded or marginal costs of service? If so, please explain.**

e. **Please provide a real or hypothetical example of the calculation of the Maximum Allowable Investment for a firm gas service extension under Rate 120 and explain how the Project Estimated 3'd Year Annual Dk is calculated.**

Response:

a. The reduction in the maximum delivery charge is a result of the increased revenue that will be recovered through the proposed increase in the Basic Service Charge. Both the increase in the Basic Service Charge and a corresponding decrease in the distribution delivery charge are supported by the cost studies.

b. The cost to serve the large interruptible customers is less on a per unit basis as demonstrated in the embedded and the marginal cost of service studies. Small interruptible customers also have a higher priority of service than the large interruptible customers.

c. The Rate 93 tariff memorializes an agreement Montana-Dakota has with WBI Energy Transmission, Inc. (WBI) to provide meter reading services for two accounts that are royalty gas customers of WBI. The customers are not part of Montana-Dakota's distribution system and Montana-Dakota does not provide any service to the customers. WBI

reimburses Montana-Dakota for meter reading costs at a rate of $0.04 per Mcf. Montana- Dakota records the revenue from WBI as Miscellaneous Revenue.

d. No.

e. Please see Attachment A for a demonstration of the Maximum Allowable Investment (MAI) and contribution requirement for a main extension to serve 3 residential customers. In this example, it is assumed that the main extension will serve three customers with each of those customers connected over the three year period. The 3rd year projection is used in those instances where additional connections are either known or anticipated over a three year period. If connections beyond year 1 are not anticipated with certainty the MAI will be based on year 1 customers and if customers connect after year 1 the MAI is recalculated as provided for in the Gas Extension Rate 120 tariff.

MONTANA-DAKOTA UTILITIES CO.
GAS EXTENSION ANALYSIS
Montana

Estimated Revenue

First Year Expected Load	86.0	Dkt	Meters Installed in First Year	1
Second Year Additional Load	86.0	Dkt	Meters Installed in Second Year	1
Third Year Additional Load	86.0	Dk	Meters Installed in Third Year	1
For	12	months		

Third Year Distribution Delivery Rev	$290.51	3rd Year Basic Service Charge Revenue	$228.60
		Total Distribution Revenue	$519.11
		Total Customers	3

Estimated Capital Expenditure

Main		$ 1,058.00
Service Line		1,680.00
Miscellaneous		0.00
ES & GA	9.65%	264.22
Total Estimated Costs		$ 3,002.22

Maximum Allowable Investment

Maximum Allowable Investment	19.954%	$ 2,601.53	Annual Distribution Revenue by Year 3 Divided by LARF where LARR = Levelized Annual Revenue Requirement
Contribution Required (Adjusted for Taxes)		$479.06	
Contribution per customer		$159.69	