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

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

December 12, 2012

Mr. Robert Nelson
Montana Consumer Counsel
111 North Last Chance Gulch, Suite 1B
PO Box 201703
Helena, MT 59620-1703

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

Dear Mr. Nelson:

Montana-Dakota Utilities Co. electronically submits its responses to the Montana Consumer Counsel's data requests dated November 30, 2012. Responses to the following requests are attached:

MCC-001	MCC-034	MCC-069	MCC-087
MCC-002	MCC-035	MCC-070	MCC-088
MCC-003	MCC-039	MCC-071	MCC-089
MCC-008	MCC-048	MCC-072	MCC-090
MCC-011	MCC-049	MCC-074	MCC-091
MCC-012	MCC-050	MCC-079	MCC-092
MCC-014	MCC-051	MCC-080	MCC-093
MCC-015	MCC-052	MCC-082	MCC-094
MCC-017	MCC-053	MCC-083	MCC-097
MCC-019	MCC-061	MCC-084	
MCC-028	MCC-063	MCC-085	
MCC-031	MCC-065	MCC-086	

The attachments for response numbers MCC-050, MCC-052, MCC-072, MCC-091 and MCC-092 are being provided on a CD sent to each of the parties.

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachments
cc: Service List

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

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MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-001 RE: Adjustment No. 1 - Sales & Transportation Revenues
Witness - Mulkern

The testimony (page 4, line 23 through page 5, line 1) indicates this adjustment is exclusive of the unreflected gas cost adjustment and eliminates unbilled revenues.

a. Is the sole purpose of this adjustment to restate revenue per books to the level of revenues that reflects the latest purchased gas adjustment? If not, explain any other purposes for this adjustment.

b. Have there been any other changes in rates between the beginning of the test year and today? If so, explain any such changes.

c. Is it correct that the $(13,880,459) is to reflect the lower cost of gas as proposed in Statement G, Adjustment No. 5? If not explain why not.

Response:

a. The purpose of Adjustment No.1 is to restate the 2011 per books revenue to reflect revenue at currently approved rates and the August 1, 2012, Gas Cost Tracking Adjustment adjusted for annual gas costs, excluding the Surcharge Adjustment.

b. No, there have been no rate changes since the beginning of the test year.

c. The adjustment to the cost of gas of $13,880,459 (Adjustment No. 5) includes changes in volumes for weather normalization and annualization as well as using an annual cost of gas for 2012.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-002 RE: Adjustment No. 1 - Sales & Transportation Revenues
Witness - Mulkern

a. Explain why the unbilled revenues are eliminated in this adjustment and provide the impact on sales and transportation revenues, by class, of this elimination.

b. Explain why the exclusion of these unbilled revenues does not result in less than a full year of revenue for this test year.

c. Provide a schedule that shows the level of unbilled revenue, by class, at the end of 2009, 2010 and 2011.

Response:

a. The revenues reported for 2011 were on a calendar basis. The unbilled revenue amount reflects the change in the unbilled amount (estimated revenue from deliveries to customers during the month and not yet billed) from the previous year and is required to state the revenues on a calendar basis. Adjustment No. 1 restates the billed volumes for 2011 at current rates and compares the calculated revenue to the per books calendar revenue.

b. The revenues at current rates reflect the volumes billed to customers for the twelve months ending December 31, 2011 and constitutes a twelve month period of volumes and revenue.

c. Unbilled revenue is not available by rate class. The total unbilled revenue, which is the change in the unbilled amount from the previous year, for the years ending 2009, 2010 and 2011 were:

2009	($2,120,953)
2010	(848,729)
2011	(1,254,664)

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-003 RE: Adjustment No. 1 - Sales & Transportation Revenues
Witness - Mulkern

a. Provide a detailed explanation as to why this adjustment is exclusive of the unreflected gas cost adjustment.

b. Explain and document what the impact on this adjustment is as a result of it being exclusive of the unreflected gas cost adjustment.

Response:

a. The unreflected gas cost adjustment is excluded from the revenue and cost of gas as it is a true-up of gas costs from a prior period.

b. The impact of the exclusion is zero as the unreflected gas cost adjustment is also excluded from the cost of gas.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-008 RE: Adjustment No. 4 - Other Operating Revenues
Witness - Mulkern

Provide all work papers, analyses, memos and other supporting documentation that support the portion of this adjustment related to the gain/(loss) on the Disposal of Property.

Response:

Please see the Statements and Exhibit Workpapers, Statement H, page 61 through 62.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-011 RE: Adjustment No. 5 - Cost of Gas
Witness - Mulkern

a. Provide a copy of the August 2012 PGA referenced in footnote 3 on Rule 38.5.157, Statement G, page 3 of 15.

b. Provide all supporting documentation for the distribution loss factor of 0.72% in footnote 2 on Rule 38.5.157, Statement G, page 3 of 15.

Response:

a. Please see the Statements and Exhibit Workpapers, Statement G, pages 39 and 40.
b. The distribution loss factor of 0.72% is the same as established in Docket No. D2002.5.59 and used in Docket No. D2004.4.50.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-012 RE: Adjustment No. 6 - Labor Expense
WITNESS - Mulkern

Provide a work paper that shows the breakdown of the labor expense adjustment into its component parts, i.e., the 3% increase for union employees, the 2.5% increase for non-union employees, the adjustment for incentive compensation to reflect a three year average, and amortization of severance amounts paid in 2009.

Response:

Please see the Statement and Exhibit Workpapers, Statement G, page 41 and 42 for the detail of the labor expense adjustment by component parts.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-014 RE: Adjustment No. 6 - Labor Expense
Witness - Mulkern

The footnote at Rule 38.5.157, Statement G, page 4 of 15 does not mention the "incentive compensation adjusted to reflect a three average" (Mulkern Direct Testimony, page 6, lines 9-10). Should the footnote include this reference or is the Direct Testimony misstated?

Response:

Yes, the footnote on Rule 38.5.157, Statement G, page 4 of 15 should state that incentive compensation is adjusted to reflect a three year average.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-015 RE: Adjustment No. 6 - Labor Expense
Witness - Mulkern

Referring to Statement Workpapers, page G-41, footnote 2, please explain why you added the "amortization of severance - 3 years" of $506,340 to amounts that already include severance.

Response:

As noted in the statement workpapers, page G-41, the total severance amount of $1,519,021 is excluded from the 2009 bonus accrual. That amount is then amortized over three years, equaling $506,340 and added back into the three year average of bonuses.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-017 RE: Adjustment No. 6 - Labor Expense
Witness - Mulkern

Provide a schedule that shows actual 2010 labor expense for the gas utility and for Montana gas operations in the same format and detail as shown on Rule 38.5.157, Statement G, page 4 of 15.

Response:

Please see the table below.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA
LABOR EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2010

	Per Books	
	Gas Utility	Montana
Other Gas Supply	$209,023	$60,444
Distribution	11,878,856	3,385,508
Customer Accounting	3,441,891	1,062,023
Customer Service	240,654	34,923
Sales	315,389	105,821
A&G	3,648,645	1,048,430
Total	$19,734,458	$5,697,149

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-019 RE: Adjustment No. 6 - Labor Expense
Witness - Mulkern

a. Please explain why the labor adjustment of 4.74% that is shown in the Statement Work Papers, page G-41 includes the electric utility.

b. Referring to footnote 1 on the same page, please fill in the "x" with a page number(s).

Response:

a. Montana-Dakota developed the labor increase percentage based on total utility wages in order to determine the combined union and non-union increase as gas O&M labor is not available by union and non-union. The percentage increase is then applied to Montana gas operations.
b. Please see Attachment A.

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

	Gas		Electric		Total		
	2010	2011	2010	2011	2010	2011	Pro Forma 1/
5110	$18,724,960	$18,944,172	$20,960,871	$21,657,050	$39,685,831	$40,601,222	$41,701,320
5120	1,061,662	1,541,831	1,814,993	2,051,931	2,876,655	3,593,762	3,691,136
5130	574,124	862,190	797,038	842,927	1,371,162	1,705,117	
5131	1,654,477	988,797	1,927,040	1,109,292	3,581,517	2,098,089	
5140	63,586	87,204	11,802	46,390	75,388	133,594	137,213
5150	31,985	17,885	60,557	30,162	92,542	48,047	49,349
5193	208,078	173,549	234,855	199,060	442,933	372,609	382,705
Total	22,318,872	22,615,628	25,807,156	25,936,812	48,126,028	48,552,440	45,961,723
Change		1.33%		0.50%			
Incentive Compensation	(2,228,601)	(1,850,987)	(2,724,078)	(1,952,219)	(4,952,679)	(3,803,206)	
	20,090,271	20,764,641	23,083,078	23,984,593	43,173,349	44,749,234	45,961,723
% Change excluding Incentive Comp		3.36%		3.91%		3.65%	2.71%
3 year average restated Incentive Comp: 2/					4,890,327	4,890,327	4,890,327
With 3 year average Incentive Comp:					$48,063,676	$49,639,561	$50,852,050
% Change with average Incentive Comp							4.74%

1/ Reflects an increase of 3% for union and an increase of 2.5% for non-union employees as referenced in Total Utility Wages page X - page 42.
2/ Average bonuses including severence.

	2009 3/	2010	2011	Average
Gas	$2,058,896	$2,228,601	$1,850,987	$2,046,161
Electric	2,337,182	2,724,078	1,952,219	2,337,826
Total	$4,396,078	$4,952,679	$3,803,206	$4,383,987

Amortization of severance - 3 years	506,340	506,340
3 year average Incentive Comp	$4,890,327	

3/ Excludes $1,519,021 of severance pay recorded in Incentive Comp in 2009.

Response No. MCC-019
Attachment A
Page 1 of 1

G-41

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-028 **RE: Adjustment No. 7 - Benefits Expense Supplemental Insurance portion**
Witness - Mulkern

a. Is the adjustment to $0 the elimination of any SISP expenses from the revenue requirement in this case? If not, please explain the nature and purpose of this adjustment.

b. Is there any SISP included anywhere else in the revenue requirement in this case? If so, where?

Response:

a. Yes, SISP expense is eliminated along with all of the SISP related tax adjustments.
b. No.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-031 RE: Adjustment No. 9 - Company consumption

Provide all work papers, analyses, memos and other documentation that support the "annualized" amount $56,986,140 as show on Statement Work Papers, page G-53.

Response:

Please see Rule 38.5.164, Statement H, page 5 and Statement and Exhibit Workpapers, Statement H, pages 4 through 18.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-034 RE: Adjustment No. 12 - Insurance expense
Witness - Mulkern

Provide a complete list of insurance policies - show insurer, the type of coverage and the expense included in the revenue requirement in this case.

Response:

Please see Statement Workpapers, Statement E, pages E-4 through E-12.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-035 **RE: Adjustment No. 12 - Insurance expense**
Witness - Mulkern

a. Provide all work papers, analyses, memos and other documentation that support the gas utility insurance expense of $1,013,243.

b. Provide all work papers, analyses, memos and other documentation that support the allocation/assignment of $258,134 of the gas utility amount to Montana.

Response:

a. Please see Statement Workpapers, Statement G, page G-2.
b. Please see Statement Workpapers, Statement E, page E-4.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-039 RE: Adjustment No. 14 - Regulatory Commission Expense
Witness - Mulkern

Provide the dates that the last three base rate cases were filed by MDU in Montana related to the gas operation.

Response:

The last three general gas cases that were filed in Montana were:

Docket No. D2005.9.418 - filed September 30, 2005 (Withdrawn January 26, 2006).
Docket No. D2004.4.50 - filed April 1, 2004.
Docket No. D2002.5.59 - filed May 17, 2002.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-048 RE: Adjustment No. 18 - MPSC and MCC taxes
Witness - Mulkern

a. Are the rates for the MCC and the MPSC shown on Rule 38.5.174, Statement K, page 4 of 4 the latest known such tax rates of which MDU is aware? If not, provide the most recent known rate(s).

b. Do the rates change on October 1 of each year? If yes, provide the rates effective as of October 1, 2012.

Response:

a. The rates used in the calculation of the PSC and MCC taxes were effective October 1, 2011. On September 27, 2012, the Montana Commission issued Final Orders in Docket Nos. D2012.9.97 and D2012.9.98 setting forth new tax rates to be effective October 1, 2012.

b. Yes, effective October 1, 2012 the MCC tax rate is 0.07 percent and the PSC tax rate is 0.23 percent.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-049 RE: Statement J, page 9 of 20, Adjustment No. 20
Witness - Mulkern

Provide all work papers, analyses, memos and other documentation that support this adjustment to deferred taxes.

Response:

Please see Rule 38.5.169 Statement J, page 18.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-050 RE: Commission orders
Witness - Goodin

For each jurisdiction where the Company provides electric or gas retail utility service, provide a copy of the most recent general rate case decision for the electric and gas operations in each of the states.

Response:

Please see Attachment A on the enclosed CD for the Orders from the following cases. Due to the voluminous nature of this response, only one copy is being provided to the requesting party.

Montana Electric Docket No. D2010.8.82
North Dakota Electric Case No. PU-10-124
South Dakota Electric Docket No. F-3576
Wyoming Electric Docket No. 20004-81-ER-09

Montana Gas Docket No. D2004.4.50
North Dakota Gas Case No. PU-04-97
South Dakota Gas Docket No. NG04-004
South Dakota East River Gas Docket No. NG05-002
Wyoming Gas Docket No. 30013-GR-02-127

Attachment A

REC'D
AUG-5 2011
REGULATORY AFFAIRS

Service Date: August 2, 2011

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

* * * * *

IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO., Application for Authority To Establish Increased Rates for Electric Service	)))	REGULATORY DIVISION DOCKET NO. D2010.8.82 ORDER NO. 7115d
IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	))))	REGULATORY DIVISION DOCKET NO. D2008.5.53 ORDER NO. 7010a
IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	))))	REGULATORY DIVISION DOCKET NO. D2009.6.87 ORDER NO. 7011a
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	))))	REGULATORY DIVISION DOCKET NO. D2009.12.153 ORDER NO. 7055a
IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	))))	REGULATORY DIVISION DOCKET NO. D2010.6.66 ORDER NO. 7094a
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	))))	REGULATORY DIVISION DOCKET NO. D2010.11.109 ORDER NO. 7125a

FINAL ORDER

Appearances

For the Applicant:

John Alke, Attorney at Law, Hughes, Kellner, Sullivan & Alke, PLLP, 40 W. Lawrence, Suite A, Helena, Montana, 59624

For the Intervenors:

Mary Wright, Attorney at Law, Montana Consumer Counsel, 111 North Last Chance Gulch Suite 1B, Helena, Montana, 59620-1703

Thorvald A. Nelson, Attorney at Law, Holland & Hart, 8390 East Crescent Parkway, Suite 400, Greenwood Village, Colorado 80111, on behalf of Encore Operating LP, ConocoPhillips, and Burlington Resources

Before:

Travis Kavulla, Chairman
Gail Gutsche, Vice Chair
W.A. (Bill) Gallagher, Commissioner
Brad Molnar, Commissioner
John Vincent, Commissioner

Commission Staff:

Leroy Beeby, Rate Analyst
Eric Eck, Revenue Requirements Bureau Chief
Scott Fabel, Rate Analyst
Sarah Norcott, Attorney, Legal Division
James C. Paine, Attorney, Legal Division
Will Rosquist, Rate Design Bureau Chief

Procedural History

1. On August 12, 2010, Montana-Dakota Utilities Co. (MDU) filed with the Montana Public Service Commission (Commission or PSC) an application for authority to increase its electric service rates in Montana by $5,502,341. MDU proposed that the increase be recovered from its customers by increasing annual customer class rates as follows: Residential rates by $1,869,589 (a 14.5 percent increase), Small General Service rates by $1,016,434 (a 13 percent increase), Large General Service rates by $2,492,644 (a 12.3 percent increase), Municipal Pumping rates by $55,297 (a 14.5 percent increase), and Lighting rates by $68,377 (an 8.6 percent increase).

2. Concurrent with its general electric rate increase application, MDU requested an interim increase in electric revenues of $3,125,808. MDU's interim request represented a uniform percentage rate increase of 7.43 percent.

3. On August 18, 2010, the Commission issued a Notice of Application and Intervention Deadline. Encore Operating LP, ConocoPhillips, and Burlington Resources (collectively

referred to as Encore) and Montana Consumer Counsel (MCC) petitioned for and were granted intervention.

4. The Commission issued Procedural Order No. 7115 on October 8, 2011.

5. On December 3, 2010, MDU submitted a letter that revised its filing to reflect changes resulting from the federal Small Business Jobs Act. The Act contained a 50 percent bonus tax depreciation for 2010, which applied to MDU's 2010 plant additions and reduced the revenue requirement originally filed by MDU by $562,511, to $4,939,830.

6. Intervenor pre-filed testimony was submitted by Encore on December 17 and December 20, 2010, and by MCC on December 17 and December 23, 2010.

7. On January 27, 2011, the Commission issued a Notice of Public Hearing.

8. On January 31, 2011, MDU filed its rebuttal testimony.

9. On February 8, 2011, the Commission issued Interim Order 7115b, granting MDU interim rate relief of $2,640,725 to be allocated to customer classes on a uniform percentage basis.

10. On February 23, 2011, a joint request from MDU, MCC and Encore to vacate the noticed February 28, 2011, hearing was received by the Commission.

11. On May 9, 2011, MDU, MCC and Encore submitted an all-party Stipulation that, if accepted by the Commission, would resolve all contested issues in the case.

12. On May 12, 2011, the Commission issued a Notice of Public Hearing regarding public witness hearings to be held in Sidney, Montana, and Miles City, Montana. On June 1, 2011, a public witness hearing was held in Sidney, Montana. On June 2, 2011, a public witness hearing was held in Miles City, Montana.

13. On May 17, 2011, MDU filed a Motion in Limine (Motion) seeking an order from the Commission which admits into evidence all pre-filed testimony and exhibits in the docket without the need for each witness to be physically present at the hearing. The Motion stated that MCC and Encore agreed to support such an order. After a duly noticed business meeting, the Commission granted the Motion with the condition that certain witnesses, to be identified by the Commission and its staff, would be available by telephone and it issued Order No. 7115c on June 20, 2011.

14. On May 31, 2011, the Commission issued a Notice of Public Hearing regarding the public hearing to be held in Helena, Montana. On June 29, 2011, the public hearing was held in Helena, Montana, as noticed.

Summary of Prefiled Testimony on Revenue Requirements Issues

MDU Direct Testimony

David L. Goodin

15. Goodin, president and chief executive officer of MDU, provided an overview of the utility's electric operations and explained that the major reasons for MDU's rate increase application were: (1) increased investment in facilities, including expansion of wind generation in the Cedar Hills and Diamond Willow projects - Goodin said MDU's gross investment in Montana electrical operations has increased by over $58 million from the end of 2006 to the pro forma levels included in the case; (2) a decline in MDU's total company wholesale sales margin from $9.8 million in 2006 to $600,000 in 2009; and (3) recovery of the deferred generation costs associated with the proposed Big Stone II, Gascoyne and Milton Young III generation projects.

Andrea L. Stomberg

16. Stomberg, MDU's vice president of Electric Supply, listed the following MDU capital investments that were included in the application: a $4 million new Montana substation that was built in 2007; a $3.4 million interconnection for the Cedar Hills wind farm; over $12 million in substation upgrades; $4.6 million in generation efficiency projects; $10.1 million in generation-related environmental projects; $2.3 million in generation-related risk reduction projects; $7.5 million in generation operation sustaining projects; an estimated $3.56 million for the Heskett Station Unit 1 maintenance and upgrade project; and significant investments in new wind generation and the Glen Ullin waste heat recovery unit.

17. Regarding MDU's proposal to recover from Montana ratepayers approximately $3.4 million, or close to 25 percent, of MDU's development costs associated with the canceled Big Stone II coal plant, Stomberg said MDU's costs were prudently incurred to develop a generating resource even though the plant will not be built. She explained that MDU pursued the Big Stone II project with other project owners after determining it would be a prudent long-term generating resource, but abandoned it when it was clear that, due to changed circumstances, it was not likely to be built. According to Stomberg, MDU also seeks to recover costs it incurred to evaluate two other baseload projects that were not built: the Gascoyne coal plant in North Dakota ($2.1

million) that was abandoned in favor of the ill-fated Big Stone II project and the Milton R. Young III coal plant ($332,000).

18. Stomberg stated that MDU constantly evaluates potential new sources of power to serve its customers and that both the Gascoyne and Milton R. Young III plants were opportunities to achieve economies with regional power plants. Stomberg asserted the plant development costs were a necessary cost associated with the development of MDU's next generating facility and should be recovered from customers.

19. Stomberg explained that, after requesting proposals, MDU secured a purchased power agreement that along with existing resources will meet customer needs through 2015.

J. Stephen Gaske

20. Gaske, senior vice president of Concentric Energy Advisors, Inc., provided testimony on the cost of common equity based primarily on his Discounted Cash Flow (DCF) analysis of a group of proxy companies that have similar risks as that of MDU's Montana electric utility. He described his analyses and concluded with recommending a return on equity (ROE) for MDU of 11.5 percent. This, he said, was within the range of his analyses of between 10.9 and 13.4 percent.

Garret Senger

21. Senger, MDU's controller and chief accounting officer, sponsored MDU's exhibits of the balance sheet for December 31, 2009, and June 30, 2010, and income statement for periods ending December 31, 2009, and the 6 months ending June 30, 2010. Senger also testified regarding the overall cost of capital, capital structure and overall debt and preferred equity costs. Senger stated that the overall rate of return sought by MDU is 8.778 percent. According to Senger, the debt costs in this application reflect a 40-basis-point reduction in borrowing costs from the cost of debt agreed to in the settlement of MDU's last rate case. He explained that MDU's requested 11 percent ROE within the overall requested rate of return is supported by Gaske's testimony, but that the requested return also recognizes the current economic environment and is a 50-basis-point reduction from Gaske's recommended ROE of 11.5 percent.

Darcy J. Neigum

22. Neigum, MDU's systems operations and planning manager, stated that the expiration in 2006 of a long-term power contract with Basin Electric along with the 2005 startup of the Midwest ISO energy market and the subsequent ancillary services market significantly reduced

MDU's opportunities for wholesale sales of excess electricity. According to Neigum, going forward MDU expects to see continued decreased wholesale sales and margins compared to historical levels. For 2010, he said MDU forecasted wholesale sales of 122,768 MWh, an annual margin of $667,752 with an average margin per sale of $5.37 per MWh.

23. Neigum discussed MDU's new generating resource additions since 2007. They include: the 19.5-MW Diamond Willow wind project, which commenced commercial operation in February 2008 and is already included in rates; the 5.3-MW Glen Ullin #6 heat recovery generating station, which commenced commercial operation in June 2010, and cost $16.7 million; the 10.5-MW expansion to Diamond Willow, which commenced commercial operation in June 2010, and is estimated to cost $24.9 million; and the 19.5-MW Cedar Hills wind project, which commenced commercial operation in June 2010, and cost $46.6 million.

24. Neigum said that MDU will meet Montana's 2010 Renewable Portfolio Standard (RPS), which requires that 10 percent of the electricity to serve Montana customers comes from renewable sources. The Montana RPS requirement increases to 15 percent in 2015; Neigum said MDU's addition of the Diamond Willow expansion means MDU is on its way to satisfying the 2015 requirement.

Stephanie L. Bosch

25. Bosch, MDU's regulatory analyst supervisor, discussed the development of the pro forma sales volume that formed the basis for Adjustment No. 1 to operating revenues.

Rita A. Mulkern

26. Mulkern, MDU's regulatory analysis manager, sponsored electric utility income statement exhibits and explained and supported with workpapers the adjustments that MDU made to the actual expenses in developing the test period cost of service. She also sponsored exhibits showing the calculation of MDU's revenue requirements for the utility. Mulkern explained MDU's proposals for changes to the fuel and power cost tracking adjustment. MDU proposed to eliminate the wholesale sales margin sharing adjustment and, instead, credit 85 percent of all wholesale margins as a credit in the fuel and power cost tracking adjustment. MDU also proposed to include Midwest ISO regional market administration charges in the fuel and power supply cost tracking adjustment.

27. Mulkern provided MDU's responses to the issues the Commission directed MDU to address in the PSC's final order in the last rate case: MDU's treatment of sales for resale and the

merits of decoupling. Regarding MDU's treatment of sales for resale, Mulkern pointed to Neigum's testimony on the decline in wholesale sales margin and MDU's proposal to eliminate the current wholesale sales margin sharing adjustment and replace it with a credit in the fuel and power cost tracking adjustment. Regarding decoupling, Mulkern testified that MDU does not recommend implementing a decoupling mechanism at this time.

AUS Consultants

28. AUS Consultants performed depreciation studies on both the MDU-Utilities Common Plant and MDU-Electric Division based on a year ending December 31, 2008.

29. The proposed rates, if applied for common plant for December 2008, would result in a depreciation expense of $1,677,496 rather than the present (2008) expense of $2,410,513, a decrease in depreciation expense of $733,017. This is a change in the composite rates from 5.63 percent to 3.92 percent.

30. For the same period for MDU's Electric Division, the study suggests an annual depreciation expense of $23,812,407, rather than $22,087,830, which is an increase of $1,724,577 from the 2008 rates. This is a change in the composite rates from 3.04 percent to 3.27 percent.

MCC Response Testimony

Albert Clark

31. Clark, a consultant for MCC, concluded that MDU's revenue increase request of $5,502,581 (subsequently reduced to $4,939,830) is excessive. He recommended a revenue increase of no more than $583,696. Additionally, Clark suggested if the Commission rejected the proposed margin sharing arrangement with a base of $0, the level of the allowed revenue increase should be reduced by an additional amount to account for a revenue credit for off-system sales revenues at the representative level of sales included as the base.

32. Clark recommended rejecting MDU's post-test-year adjustments that are based on MDU's 2010 operating budget. Clark's proposal recognizes actual increases and decreases experienced after the close of the test year and the most recent 12 months of actual data. According to Clark, his change represents a known and measurable level of cost as opposed to a speculative budget amount as used by MDU.

33. Clark made the following adjustments to MDU's pro forma results of operations: increase MCC and PSC taxes by $54,642; increase test year miscellaneous revenues by $19,585;

reduce the 401-K expense by $30,660; reduce postage expense by $4,460; reduce insurance expense by $16,458; reduce subcontract labor by $486,877; reduce labor expense by $169,393; increase post-retirement benefit expense by $29,382; increase medical/dental expense by $20,844; reduce worker compensation expense by $8,556; reduce uncollectible expense by $726; reduce advertising expense by $6,304; reduce the Montana electric allocation by $27,653 to reflect Clark's proposed change in the allocation of the North Dakota Coal Conversion Tax; reduce test-year expenses for the Montana electric operation by $5,879 to reflect use of the capacity allocation factor as related to production at the Lewis & Clark station and to the transmission function; reduce test year property taxes by $58,204; and reduce the Supplemental Income Security Program (SISP) expense by $353,660.

34. Clark proposed an adjustment to reflect the depreciation rates that MCC witness Jacob Pous determined to be appropriate. The revised depreciation rates have an impact on depreciation expense and the accumulated provision for depreciation.

35. Clark proposed adjustments to MDU's rate base. First, he recommended the amount of post-test year plant that should be included in rate base is $2,788,976 of post-test-year plant additions rather than MDU's proposed $7,541,539. Clark argued that no post-test-year plant should be included in rate base because, in his opinion, MDU did not show that the plant is non-income producing and because his analysis determined that some of the plant MDU proposed for inclusion in rate base had not been in service within 12 months after the close of the historical test year and was therefore ineligible. Clark noted his proposed reduction in plant affects depreciation expense, the depreciation reserve and property taxes.

36. Clark also proposed rate base reductions of $1,422,816 related to the accumulated provision for depreciation; $580,005 related to including accumulated deferred income taxes in rate base; and $137,108 related to reallocating the Diamond Willow deferred income taxes on the same hybrid basis as MDU proposed for allocating the plant's costs.

37. Clark's final adjustment to rate base (and an accompanying adjustment to expense) was related to MDU's proposal to include deferred generation costs in its revenue requirement. MDU claimed total costs of $15,296,364, of which $3,788,440 was allocated to Montana electric operations. MDU requested the cost to be amortized over 10 years and that the first year average unamortized balance be included in rate base. Clark objected in part to the total costs claimed and objected in total to the rate base inclusion. He contended there is no justification for

ratepayers to pay a return on capital for projects that never did, and never will, produce a plant that is used and useful.

38. Clark proposed to allow the amortization of the expenditures over a 10-year period with one adjustment that would provide for a return *of* the capital to stockholders, but not a return *on* it. Clark proposed removing the $2,387,019 in Allowance for Funds Used During Construction (AFUDC) from the total amount to be amortized, allocated down to Montana electric operations, and reducing the claimed amortization expense by $68,099.

39. Clark accepted MDU's proposal to reflect bonus depreciation for 2010 plant additions, but only to the extent that 2010 plant was included in rate base. Clark calculated that approximately $410,000 of the claimed revenue requirement reduction was related to the Diamond Willow expansion and the Cedar Hills wind farm. Clark stated that the remaining $153,000 of MDU's proposal was related to its claimed level of other post-test year plant investment. Since he proposed to remove the majority of these post-test year investments, the portion related to plant not included in rate base should not be reflected in the revenue requirement. He proposed to disallow approximately 63 percent of MDU's proposed 2010 plant investment, and would then restore 63 percent of the $153,000 to the revenue requirement.

40. Clark's last adjustment to the pro forma income statement was to synchronize the interest expense with the capital structure and the rate base plus non-rate base construction work in progress. The effect of the adjustment was to decrease interest expense by $308,204, which, in turn, increased current income tax expense by $121,394.

41. Clark recommended against approval of MDU's proposed margin-sharing mechanism unless a larger share of the margins flows to ratepayers and MDU's fuel and purchased power adjustment mechanism is approved with a similar sharing arrangement as proposed by Wilson.

42. Clark recommended the Commission reject MDU's proposed new Renewable Resource Cost Recovery Rider Rate 56 and Transmission Cost Recovery Rider Rate 57. Clark opposed the rate schedules because he said they both anticipate single-issue rate adjustments; MDU offered no explanation of their use; it appears they could result in blanket preapproval for investments in unspecified future projects; and there is no reason for the Commission to agree to these rate schedules and examine the results of their applicability later.

Jacob Pous

43. Pous, a principal in the firm of Diversified Utility Consultants, Inc., filed testimony on behalf of the MCC in response to the depreciation study submitted by MDU. The MDU study was based on overall plant as of the end of December 31, 2008, and resulted in a proposed $22,087,830 total company annual depreciation expense. The proposal in the study represented an increase of $1,724,577 compared to the depreciation expense that would occur utilizing current rates. Pous limited his analysis to Production plant accounts. He noted that the $1.7 million increase in depreciation expense in MDU's study is actually a $2,706,497 increase for production plant and a $981,920 reduction to plant other than production plant.

44. Pous identified three main production plant issues. Regarding production plant life, he recommended life spans that reflect either MDU's expected retirements during the planning horizon of its Integrated Resource Plan or a 60-year minimum life span, which he said had the net effect of an approximate $3.5 million reduction to total company depreciation expense. Regarding interim retirements, Pous recommended a retirement ratio approach based on company-specific history, which he said would result in a $1.2 million net reduction to total company depreciation expense. Regarding production plant net salvage, Pous recommended relying on more recent decommissioning cost estimates than MDU did to arrive at an approximate $2.2 million reduction in annual depreciation expense.

45. According to Pous, the combined impact of his recommendations is a $6.2 million reduction to total company production plant depreciation expense (prior to the allocation to the Montana retail jurisdiction).

John Wilson

46. Wilson, president of J.W. Wilson & Associates, provided testimony on behalf of MCC on the issues of rate of return and capital structure. Wilson performed a DCF analysis, a Capital Asset Pricing Model (CAPM) analysis and a comparable earnings analysis. He recommended an ROE range between 8.5 percent and 10 percent. Wilson proposed a 9.5-percent ROE to calculate a recommended return on rate base. Wilson claimed his 9.5-percent ROE acknowledges that MDU has provided and is expected to continue to provide adequate service to its Montana customers and also recognizes the modest level of business risk for electric utility service and MDU's comparatively high common equity ratio. Based on a 9.5 percent ROE allowance, MDU's allowed return on its electric utility rate base would be 8.0 percent:

	Ratio	Cost	Allowed Return
Long Term Debt	43.239%	6.845%	2.960%
Short Term Debt	3.211%	2.535%	0.081%
Preferred Stock	2.397%	4.592%	0.110%
Common Equity	51.153%	9.500%	4.860%
		Overall Return	**8.011%**

47. Wilson used the actual capital structure in his calculation of rate of return but stated that a 50-percent common equity ratio is at the high end of the reasonable range for electric utility ratemaking.

Encore Response Testimony

Michael P. Gorman

48. Gorman, a consultant and managing principal with Brubaker and Associates, Inc., testified on capital structure and rate of return issues. He did not object to MDU's proposed capital structure. To derive his ROE recommendation, he used a constant growth DCF model, a sustainable growth DCF model, a multi-stage growth DCF model, a risk premium analysis, and a CAPM analysis. Gorman stated that these analyses estimate a fair ROE based on observable market information for a group of publicly traded electric utility companies that approximate MDU's investment risk. Gorman recommended an ROE of 9.6 percent with a range of between 9.4 percent and 9.8 percent. He recommended an overall rate of return of 8.06 percent.

49. Gorman also responded to the analysis performed by Gaske of MDU. He stated that MDU proposed an ROE of 11.5 percent based on Gaske's use of DCF analysis and the inclusion of flotation costs. Gorman stated that Gaske's estimates were flawed in that the growth rates used by Gaske do not represent long-term sustainable growth, but forecast growth rates for the next five years and Gaske's internal steady-state growth rates were much lower than the three- to five-year growth estimates and illustrates the non-sustainability of the short-term analyst growth rates. Gorman also stated that Gaske's flotation cost ROE adder was not based on MDU-specific equity issuance cost and as result the flotation cost adder is not a legitimate cost to include in MDU's cost of service.

David E. Peterson

50. Peterson, a consultant in the firm Chesapeake Regulatory Consultants, Inc., addressed revenue requirement issues, excluding the issues of capital structure and cost of capital.

51. Peterson stated MDU claims to have used a 12-month test period ended December 31, 2009, but its rate base presentation included forecasted plant additions through December 2010. He recommended the Commission reject MDU's post-test period adjustments. By removing post-test year plant additions, excluding the new wind resource assets, he reduced MDU's Montana rate base by $1,379,443.

52. Peterson adjusted MDU's rate base for Diamond Willow Expansion and the Cedar Hills wind projects and the first-year operating costs associated with running those two facilities. His adjustment used 32.8 percent energy and 67.2 percent demand jurisdictional allocation factors for MDU's wind investments testified to by Encore witness Rosenberg. The adjustment reduced rate base by $1,218,005.

53. Peterson objected to several of MDU's proposed rate base allowances as being outside the 2009 test period. His proposed adjustments in the categories of materials and supplies, fuel stores, prepaid insurance, unamortized loss on reacquired debt, and customer advances for construction.

54. Peterson said that the effect of his recommended rate base adjustments is to reduce MDU's electric rate base by $6,131,118, resulting in a rate base of $81,120,268.

55. Peterson recommended the following adjustments to MDU's pro forma operating income: adjust depreciation, property tax and income tax to exclude the effects of post-test year plant additions ($412,417); Diamond Willow re-allocation ($70,710); remove incentive compensation expense ($662,040); adjust depreciation expense ($2,880); shorten the amortization period for decommissioning of retired plant costs from ten to three years ($40,000); reduce advertising costs ($6,304), reflect consolidated tax savings in Montana rates ($556,404); and interest synchronization.

56. In addition, he disagreed with MDU's cost recovery proposal for the canceled Big Stone II, Gascoyne and Milton R. Young III generation projects. Peterson recommended the abandoned projects' cost be shared between MDU and ratepayers by excluding the accrued AFUDC, amounting to $2,387,019 on a total company basis from cost recovery, amortizing recoverable costs over a 40-year period, and excluding the unamortized recoverable costs from rate base. The effect of his proposed sharing mechanism on MDU's proposed revenue requirement is to reduce MDU's proposed annual amortization allowance by $298,899 and rate base by $3,598,854.

57. Peterson concluded that MDU understated its earnings potential under present rates by $1,571,308. He contended that MDU's request for a $5.5 million rate increase is excessive and that a rate increase of $483,958 would allow MDU to achieve Encore's recommended 8.06 percent overall rate of return.

MDU Rebuttal Testimony

Rita A. Mulkern

58. Mulkern disagreed with MCC witness Clark's general criticism of MDU's use of the 2010 operating budget. She contended MDU did not use the budget on a wholesale basis; rather the budget was used as a guide to determining increases or decreases in expenses affecting the test period. She also stated that Clark was inconsistent in deriving his revenue and expense levels because, in some cases, he used the 12 months ending October 31, 2010 expense levels, but, in others, he annualized year-to-date 2010 expenses.

59. Regarding Clark's adjustments to the KVAR penalty revenue, Mulkern contended that MDU's use of a three-year average was appropriate and that Clark had not objected to it in the last rate case when the three-year average was higher than the per-books amount. She said if the Commission decides that the two-year historical and one year budget information is appropriate, then that time period should be used in future cases. She argued the makeup of the three-year time period should not change in order to pick the lowest three-year period in each case. Mulkern made the same point regarding Clark's incentive compensation adjustment.

60. Mulkern claimed Clark understated MDU's insurance expense amount because he did not take into account the known and measurable changes that occurred in insurance premiums effective November 2009, January 2010 and April 2010.

61. Mulkern said Clark erred in his calculation of subcontract labor by calculating it as a credit of $331,437 instead of an expense of $331,437. When corrected, she said the adjustment would be an increase of $175,997 rather than a decrease of $486,777.

62. Regarding Clark's SISP expense adjustment, Mulkern argued Clark's position in this case is inconsistent with his position in previous MDU cases. Mulkern contended Clark changes his position on including or excluding SISP expense depending on whether it increases or reduces the revenue requirement.

63. Mulkern disputed Clark's adjustment to remove the deferred generation balance from rate base because she said Clark also should have eliminated the associated accumulated deferred

income tax balance from rate base in order not to overstate the adjustment. If the Commission accepted Clark's proposal, she said this correction would result in an increase in rate base of $673,342.

64. Mulkern said MDU does not object to Clark's adjustments to post-test period plant additions, but contended Clark's calculation of ad valorem taxes when restated for the plant additions should have included construction work in progress not yet classified, the AFUDC interest and depreciation on Coyote, and the reallocation adjustment for the wind generation.

65. Mulkern stated that with respect to the sharing of the fuel and purchased power tracking adjustment amounts, MDU believes its proposal to share 85 percent of all margins is more beneficial to customers than to establish a base with sharing over (under) a base as proposed by Clark.

66. Mulkern disagreed with MCC witness Wilson's contention that the MISO market administrative charges should not be included in the fuel and power tracking adjustment. She argued that market administrative charges are directly related to MDU's fuel and purchased power and, prior to MISO, were included in the energy cost of purchased power.

67. Regarding Encore witness Peterson's adjustments based on his interpretation of the test year in this case, Mulkern argued that Peterson had incorrectly interpreted the Commission's administrative rule and previous direction regarding the "known and measurable" standard. Mulkern contended MDU's plant additions and related adjustments met the known and measurable standard applied by this Commission. In this case, she said, MDU maintained test year relationships and included only those plant additions that were non-revenue producing.

68. She disputed Peterson's use of a strictly historical rate base that effectively disallowed MDU's recovery of the full investment in the Glen Ullin plant. She said Peterson failed to recognize the full investment in generation which has been providing electricity to customers since July 2009.

69. Mulkern contended Peterson's adjustment to prepaid insurance should be rejected because, she argued, Peterson ignored both the known and measurable standard and the matching principle.

70. Regarding Peterson's opposition to MDU's use of a three-year historical average of incentive compensation, Mulkern said MDU has consistently used that average in the development of an adjustment to labor expense in its rate cases in order to smooth out the year-

to-year fluctuations that occur. Mulkern disagreed with Peterson's argument that since the budgeted incentive compensation for 2010 was less than the three-year historical average, the use of the average was wrong.

71. Mulkern called Peterson's proposal to amortize the deferred generation costs over a 40-year period unreasonable. Referring to Peterson's testimony about "dragging out" for 10 years the amortization of the unamortized cost of the decommissioning of retired plants, Mulkern said there is no reason to drag out the recovery of deferred generation costs over 40 years. She also said Peterson made the same error as Clark in that he removed the unamortized deferred generation balance from rate base but failed to remove the associated accumulated deferred income taxes.

72. Mulkern disagreed with Peterson's proposal to amortize the unamortized balance of decommissioning costs on retired generation plants over three years rather than the five years proposed by MDU. MDU prefers a five-year period because it does not know if it will be filing a general rate case within the next three years and a five-year amortization would provide more flexibility in returning the unamortized balance to customers.

Alvin J. Feist

73. Feist, the tax planning director of MDU Resources Group, Inc., disputed Peterson's consolidated tax savings adjustment. Feist explained that under the stand-alone methodology that MDU uses to calculate taxes, the tax benefit/burden must be given to the member of the consolidated group that is responsible for generating the income or paying the expenses giving rise to a deduction or a tax burden. Feist said MDU has long used the stand-alone method for allocating consolidated tax liability in rate cases in Montana, North and South Dakota and Wyoming. He said the Federal Energy Regulatory Commission (FERC) has also supported the use of the stand-alone method of allocating income taxes among members of a consolidated group when a jurisdictional company is part of a group filing a consolidated income tax return. Feist cited specific FERC opinions and language that approved the stand-alone methodology. Feist cited a circuit court decision that sustained the FERC's application of the stand-alone methodology. Feist also said the stand-alone method conforms to generally accepted accounting principles, referring to the Accounting Standards Codification (ASC) regarding accounting for income taxes. According to Feist, the ASC has determined that the method proposed by Peterson is not consistent with its broad principles.

74. Feist disagreed with Peterson's argument that MDU realized tax savings by filing a consolidated return. He said tax benefits associated with the net operating losses of affiliates should not be considered as "tax savings." Feist provided an example of the timing nature of a tax loss by a non-regulated affiliate. The affiliate had a tax loss in Year 1 of $50,000 and taxable income in Year 2 of $50,000. If the affiliate was not a member of a consolidated return, it would be able to carryover its loss to Year 2 and offset its taxable income in Year 2, resulting in zero tax payable in Years 1 and 2. However, he said, Peterson's proposal would convert the timing nature of this benefit into a permanent tax loss to the non-regulated affiliate.

75. According to Feist, proper ratemaking policy is to keep regulated and non-regulated entities separate to the extent possible. He argued that there is no evidence that MDU's customers are bearing the expenses resulting in the tax deductions at any of the affiliated companies. He said the Commission would not allow MDU's customers to be burdened with the expenses of the affiliated companies and the Commission should likewise recognize that it would be inconsistent for MDU's customers to be allocated the tax benefits that were realized as a result of the expenses incurred by the affiliated companies.

76. Feist did not agree with Peterson's contention that ratepayers are paying for tax losses of MDU's unregulated affiliates. He said the cash benefit received by the affiliates as a result of these tax losses is not being paid by the MDU customers, but essentially is being received from the government. Feist said if the Commission reverses its past position on the stand-alone method, this change in policy would retroactively penalize MDU Resources for organizational decisions which were made in reliance on the past policy of this Commission.

77. Feist contended that Peterson ignored the 2008 MDU tax loss when he computed his five-year average and that this position is contrary to the treatment Peterson argued should be given to losses of non-regulated affiliates. He said that, under Peterson's proposal, MDU would share in the benefit of any tax losses for non-regulated affiliates, but the affiliates would not be allowed to share in the benefit of the 2008 tax loss generated by MDU. Feist indicated that Peterson's calculation should be revised to reflect the 2008 MDU tax loss and that revising Peterson's calculation results in a Montana current tax adjustment of a positive $1,047,988. MDU's requested recovery of Montana electric allocated income taxes would need to be increased by this amount, Feist said.

78. Feist argued the correct income tax allowance is determined using a stand-alone method, which results in no adjustment to the amount reflected in MDU's filing.

Anne Jones

79. Jones, MDU's human resources director, disagreed with Peterson's proposal to eliminate all incentive compensation amounts from Montana rates. According to Jones, incentive compensation should remain in MDU's cost of service because the incentive plan is designed for employees and senior management to focus on customer service metrics, safety and controlling operating and maintenance costs. She also stated that meeting an earnings threshold before payout is in customers' best interest and is common in the utility industry. According to Jones, if the Commission disallowed incentive compensation based on performance, the only viable alternative is to increase base pay to remain competitive in the labor market and retain a viable, qualified work force. She contended base pay is the most expensive way to compensate employees because other benefits such as pension and 401K contributions are dependent on base salary.

Garret Senger

80. Senger disagreed with Clark's and Peterson's recommendation to disallow AFUDC for the deferred generation costs. He said the AFUDC costs were prudently incurred to minimize long-term costs to the customers, MDU expended capital for those projects, and accruing AFUDC is a cost of the project. Senger contended that MDU followed the FERC-prescribed formula for applying AFUDC. He added that disallowing recovery of AFUDC as proposed has the potential to increase the long-term overall cost of debt and capital.

81. Regarding the issue raised by MCC witness Pous about the decommissioning rates, Senger responded that MDU is currently recording the authorized rates for decommissioning costs and has not proposed to change those rates in this case. He said MDU recognizes the need to update its decommissioning study and is in the process of developing a new study.

Earl M. Robinson

82. Robinson, a director of AUS Consultants who prepared MDU's 2008 depreciation study, disputed several aspects of the testimony of MCC witness Pous. He said Pous was selective in his rejection of MDU's increase in depreciation expense for Production plant while apparently accepting MDU's reduction for Other Plant. He claimed Pous ignored MDU-specific data and therefore his recommendation is unsupported.

83. Robinson claimed that Pous' estimates of potential life spans, the level of interim retirements that he estimated to occur during the property's life, and extrapolation of the commodity scrap values to the company's plant are irrational and inappropriate and led to what Robinson termed Pous' radical reductions to not only MDU's proposed generation plant depreciation rates, but also to its current level of annual depreciation rates.

84. Robinson disagreed with Pous' opinion that MDU used artificially short service lives for its production plant. He pointed to significant additional investments that have been made to the initial construction of the Heskett and Lewis and Clark plants from years earlier that have extended their life spans to a range of 57 to 66 years. Robinson said it is only through continued extensive investments that generation plants are able to attain the average 60 years proposed by Pous as an initial life for steam production plants. According to Robinson, Pous' proposal of a very long initial service life estimate inappropriately defers cost recovery to a future customer instead of recovering the costs over the life of the property consistent with a customer's use of and benefit from the property and related investments.

85. Robinson also took exception to Pous' assertion that MDU's 2009 IRP does not identify production plant retirements in a manner consistent with average service lives in the depreciation study. Robinson stated that the depreciation study and the IRP serve different purposes.

86. Robinson disagreed with Pous' position that an actuarial approach to estimate the average service life is inappropriate. He said that either the actuarial approach or life-span approach can be used. He stated that the analysis method used by MDU is appropriate and that Pous used an alternate mixture of inputs that resulted in a lower depreciation recommendation. Robinson stated that Pous argued against using a full mortality method stating that a majority of companies use a life span approach. Robinson stated that in his sample group, at least 50 percent used an actuarial, semi-actuarial or judgment approach. Robinson stated there is no one standard for the calculation of remaining plant life and that Pous' mix-and-match approach is invalid.

87. Regarding the issue of interim retirements, Robinson asserted that his Iowa Survival Curve/life analysis approach is appropriate and that Pous' suggested constant interim retirement rate based upon the prior 30 plus historical years is incorrect. Robinson's argument was that Pous' calculated average retirement was backward looking and gave no consideration to the increasing level of interim retirement rates as property continues to age.

88. Robinson stated that Pous' criticisms of the revision of the interim retirement curve and of the change in the curve scale between the 2002 and 2008 MDU depreciation studies are incorrect. He said a different scale has no impact on the depreciation study results and that the bottom line is that the high level of retirements has continued during the more recent period. Robinson asserted the higher retirement levels have historically continued over numerous years and there is every reason to believe that this pattern will continue into the future. Robinson stated that it is obvious that MDU's now proposed Iowa 50-R1 life and curve is clearly a superior representation of the applicable interim retirements as compared to the prior estimated 80-L0 life and curve.

89. Regarding production plant net salvage, Robinson took note of Pous' criticism of the use of the 1984 Stone and Webster fossil fuel decommissioning study and of MDU's position that the study provided a reasonable estimate of decommissioning costs. Robinson stated that MDU is presently using the authorized decommissioning rates and is not proposing any changes to decommissioning costs in this case.

J. Steven Gaske

90. Gaske responded to Wilson's and Gorman's ROE recommendations. He said his primary objection to Gorman's analysis is that he gave no consideration to his Constant Growth DCF results, which indicated an average required return for the proxy group of 11.19 percent and a median return requirement of 10.94 percent. Gaske argued that Gorman's analysis confirmed the reasonableness of his ROE recommendation.

91. According to Gaske, the most significant flaw in Wilson's analysis was the implausibility of many of its results. For example, he said, there were several instances where Wilson estimated that the required ROE was negative. Gaske contended another flaw in Wilson's analysis was the use of the entire group of 54 companies that Value Line classifies as electric utilities, plus MDU Resources Group, in his proxy group. Gaske said many of these companies are not comparable to MDU's electric utility operations and to use them as an input into the calculation of an appropriate ROE for MDU is inappropriate.

92. Gaske said he disagreed with Gorman and Wilson in other areas of their analyses, including: (1) growth rates used in their respective DCF analyses; (2) dividend yield adjustments; (3) the use of a CAPM analysis; and (4) the appropriateness and application of a

flotation cost adjustment. Furthermore, he disagreed with Gorman on the approaches used in their respective risk premium analyses and the risks faced by MDU's electric operations.

93. Gaske concluded by stating Gorman's and Wilson's recommended ROEs are inadequate because the they are based on flawed analyses and that when those analyses are corrected or refined, they support Gaske's rate of return recommendation.

Summary of Prefiled Testimony on Cost of Service & Rate Design Issues

MDU Direct Testimony

Tamie Aberle

94. Tamie Aberle, MDU's pricing and tariff manager, presented the results of MDU's embedded class cost of service study and addressed the effect of MDU's revenue requirement proposal on electric rates and customer class revenue responsibilities. She also described MDU's proposed changes to non-price tariff terms and conditions and addressed the reserved issues from Docket No. D2007.7.79 pertaining to inverted block rate structures and smart metering.

95. Aberle sponsored Statement L, which contains the details of MDU's embedded cost of service (ECOS) study. The ECOS study is based on the 12 month test period ended December 31, 2009 adjusted to reflect pro forma adjustments as sponsored by Mulkern.

96. To determine what costs to assign to each customer class, Aberle began by classifying the functionalized costs by FERC account for all rate base and income statement items as demand-, energy-, or customer-related. She directly assigned to appropriate customer classes the plant, expense, and revenue items that are identified in the FERC accounts as directly related to a specific class of customers. She allocated remaining costs using the allocation factors shown in Statement L on the basis of cost responsibility.

97. Aberle allocated investments in production and transmission plant items with an Average and Excess Demand (AED) allocator, based on a combination of the classes' average demand and non-coincident peak demand. Aberle testified that MDU analyzed each distribution plant account and allocated costs therein based on the cause for investment. Station equipment and the associated land and land rights were allocated based on the non-coincident peak demand of each class. Other distribution plant items were classified as customer- and demand-related based on an analysis of the minimum and normal system design for a typical distribution system,

with the minimum system representing the percentage of the plant accounts assigned to the customer component and the remainder classified as demand-related. That analysis indicated that the minimum investment necessary to connect a customer constitutes 82 percent of Accounts 364 (Poles, Towers & Fixtures), 365 (Overhead Conductors), 366 and 367 (Underground Conduit and Underground Conductors and Devices). She allocated customer-related distribution costs to each rate class based on the number of customers served in each rate class, and allocated the remaining demand-related distribution costs to each rate class based on the maximum demand of each rate class.

98. Aberle classified line transformers as customer- and demand-related. She used a minimum intercept method to determine the customer-related component. She explained that the minimum intercept method seeks to identify the portion of the transformer investment associated with a hypothetical zero-load condition. She calculated the zero intercept to be $1,446 and multiplied this amount by the number of transformers, which resulted in a customer component of 76 percent. She classified the remaining 24 percent of transformer costs as demand-related. She allocated the customer- and demand-related transformer costs according to weighted customer transformers and non-coincident secondary demand factors, respectively.

99. She classified the four remaining distribution cost accounts (services, meters, installation on customer premises and street lights and signal systems) as customer-related. She allocated services and meters costs to customer classes based on weighted customer factors. She directly assigned costs for installation on customer premises to the outdoor lighting class. Similarly, she directly assigned investment in street light and signal systems to the municipal lighting class.

100. With respect to the allocation of income statement items, Aberle explained that she directly assigned revenues to each customer class based on the revenues produced by each class. Any other revenues that she could not directly assign to a particular rate class she allocated based on the source of the revenue. She classified fuel, purchased power, and variable production expenses as energy-related and allocated them based on the energy requirements of each class. She classified other production expenses and purchased capacity costs as demand-related and allocated them using the AED allocator used to allocate production plant costs. She classified transmission operation and maintenance (O&M) costs as demand-related and allocated them

with the AED allocator. She said she allocated the remaining O&M expenses based on cost causation.

101. Aberle primarily used the ECOS study as a guide to apportion the proposed revenue increase to customer classes. The class revenue changes needed to bring each of the rate classes to the overall rate of return ranged from a 110 percent increase for Irrigation Rate 25 to a 29 percent decrease for Outdoor Lighting Service Rate 52. She did not propose reducing rates for the Outdoor Lighting Rate 52, but she did not allocate any of the revenue increase to that class. In allocating the revenue increase to each class, Aberle imposed a 14.5-percent cap in order to mitigate the increase to any one rate class. Aberle said the proposed rates move toward cost-based rates but do not fully reflect MDU's estimated marginal and embedded costs. Aberle's proposed class revenue increases are shown below.

Proposed interim and final rate level increases

Class	Interim	Final
Residential	7.43%	14.5%
Small general service	7.43%	13.0%
Large general service	7.43%	12.3%
Municipal pumping	7.43%	14.5%
Lighting	7.43%	8.6%
Overall	**7.43%**	**13.0%**

102. Aberle proposed increasing the base rate component (or Basic Service Charge) to $0.25 per day, or $7.60 per month, which is an increase of $2.60 per month over the current rate. She contended that amount is below the $20.92/month customer component supported by the ECOS and the $23.78/month customer cost component shown by the marginal cost study. She said MDU proposes a daily basic service charge in order to avoid prorating the monthly charge.

103. Aberle derived residential class energy rates by reducing the class's total revenue responsibility by the proposed basic service charge revenues, the seasonal differential and the projected base fuel and purchased power component for secondary service. She divided the remaining revenues by pro forma Rate 10 kwh sales to determine the rate per kwh. This produced a rate of $0.07548/kwh during summer months and $0.05148/kwh during winter months. A Base Fuel charge of $0.02084/kwh would be added to both of these rates to

determine the total energy rate. Aberle stated that she used the same process used to calculate the proposed rate components for each of the other rate schedules.

104. Aberle testified that MDU continues to offer optional time-of-day rate schedules consisting of Residential TOD 16, Small General Service TOD Rate 26 and Large General Service TOD Rate 31. These rates are designed to provide customers with an incentive to shift load to the off-peak period.

105. Aberle explained that MDU proposes to offer a new Option Residential Electric Thermal Energy Storage Rate 13 to residential customers with electric space heating that also use a thermal storage system during the off-peak hours of 10 p.m. to 8 a.m. The proposed rate for this rate schedule is a discount of $0.025 per kwh from residential rate 10.

106. She testified that MDU also proposes to offer a new General Electric Space Heating Service Rate 32, which would offer General Service customers with electric space heating an optional rate that recognizes that space heating load occurs during a period outside of the system peak. The rate would discount demand charges during the heating season October through May. The energy charges and summer season demand charge for Rate 32 would be the same as those under Large General Service Rate 30. The space heating load served under Rate 32 would be metered separately from the customer's other electric requirements.

107. Aberle explained that the proposed electric service rate schedules each contain four separate adjustment mechanisms:

a. Universal System Benefits Charge (Rate 55): the existing adjustment mechanism established to recover funds to support the Universal System Benefits program.

b. Renewable Resource Cost Recovery Rider (Rate 56): a proposed adjustment to recover costs for future investment in renewable resources. The renewable resources in the revenue requirement in this rate case (Diamond Willow wind, Cedar Hills wind and the waste heat recovery unit) would not be part of the adjustment.

c. Transmission Cost Recovery Rider (Rate 57): a proposed adjustment to recover transmission investments and federally regulated transmission related costs charged to MDU that are not part of the rates established in this rate case. The request is to establish the mechanism for future use in recovering applicable expenditures and an adjustment is not proposed to be charged at this time.

d. Fuel and Purchased Power Adjustment (Rate 58): mechanism currently established to recover the cost of fuel and purchased power.

108. Aberle addressed the reserved issue of inverted block rates from PSC Order No. 6846f, Docket No. D2007.7.79. She said that while MDU provided information in Docket No. D2009.4.56 for Residential rate schedule 10 reflecting an inverted block rate based on various assumptions, that same exercise has not been repeated in this rate case. She asserted that the fuel charge component of the energy charge is the component that would most appropriately be charged on an inverted basis because it is the true variable component that would be avoided through customer response to a price signal. She recommended making the fuel and purchased power component a separate line item on customer bills. She added that MDU does not have the ability to bill on an inverted basis at this time but indicated that MDU's new billing system would be capable of billing the fuel and purchased power charge on an inverted basis in the future.

109. Aberle also provided information on MDU's Automated Meter Reading (AMR) program as required in Order No. 6846f. She testified that MDU's AMR system is more than a meter reading system because of the communication network and use of Itron Corporation's Meter Data Management System (MDM). The MDM system is a first step in providing customers with more real time information and enhanced pricing options. She said that the AMR system is operational from the meter reading and billing perspective, with meter data collected from approximately 75 percent of the automated meters in place, and the remaining 25 percent of the automated meters being mobile read. Interval data is transmitted through the fixed network system, but the MDM system necessary to aggregate and store the interval data is not yet functional. MDU is working to enable the MDM system. She said MDU remains committed to initiating a load control program and recently refreshed the estimated cost to install and implement a program in conjunction with Honeywell Utility Solutions. Under this program, MDU would have the ability to cycle a participating customer's central air conditioner with the use of a programmable thermostat installed within a customer's home. She expects the program to get under way in the second quarter of 2011. She added that MDU will evaluate an expanded portfolio of conservation programs, including the load control program, as part of the 2011 Integrated Resource Planning process.

James Heidell

110. James Heidell, vice president of NERA Economic Consulting, presented MDU's marginal cost of service (MCOS) study.

111. Heidell stated that his study followed the commonly-used approach of cost functionalizing costs, classifying them, and allocating them to customer classes. He testified that his MCOS study reflects an estimate of marginal costs for 2012 to comply with ARM 38.5.176, which requires an estimate of costs for the study year two years beyond January 1 of the year in which the study is filed. His objective was to estimate long-run marginal costs, where long-run is a five- to ten-year horizon. He separately estimated marginal costs for generation, transmission lines, transmission substations, and distribution services. In the case of marginal generation costs, he used MDU's chronological dispatch model to estimate marginal energy costs over an eight year period, 2012-2019. He reported that MDU had less information on long-term projections of marginal transmission and distribution costs. So, to estimate these costs, he used a combination of historical costs and current actual or estimated construction costs. When using costs from different years, he adjusted them to 2012 dollars based upon an assumed inflation factor or the Handy Whitman index.

112. Heidell derived MDU's marginal generation cost by first preparing a forecast of levelized marginal energy and capacity costs over a period of 2012 through 2019. He calculated marginal energy costs using the PROSYM hourly chronological production cost model. Specifically, he used cost differences between a base case scenario and a scenario with 20 MW of incremental load to develop marginal costs for eight time periods: on and off-peak periods in winter (December – February), spring (March – May), summer (June – August), and fall (September – November).

113. He asserted that MDU's production cost model determines the least-cost dispatch of the mix of resources available to meet MDU's load based on assumptions including unit availability, heat rates, fuel costs, and ramp rates. The base case scenario reflected key assumptions about the future, including MDU's retail load, estimates of future fuel prices, and characteristics of existing generation units and power contracts. The incremental load scenario used the same assumptions about fuel costs and existing generation units and power contracts. He used a combustion turbine to ensure incremental peak loads were met, but noted that the incremental load is also served by available generation resources and market purchases defined in the base case.

114. Heidell incorporated greenhouse gas externality costs through additional PROSYM modeling. He used a PROSYM report on the percent of hours that a fuel group is on the margin

during each month for the peak and off-peak periods to assign a marginal generation unit to each time period and calculate emissions per MWh based on the plant's heat rate and the emission rate for the fuel. He calculated the marginal cost of CO_2 emissions for each month and each period based upon the weighted average time that each fuel is on the margin. He calculated these costs under two CO_2 emissions cost scenarios: $30/ton and $50/ton in 2012, with both scenarios assuming a 2.5 percent annual escalation rate (2012-2019).

115. Heidell calculated levelized marginal generation capacity costs for two time periods. For the first period, 2012-2014, he based marginal capacity cost on recently acquired summer peaking contracts. For the second period, 2015-2019, he based marginal capacity cost on the levelized cost of building a 75-MW gas-fired combustion turbine. He then levelized the costs over the full 2012-2019 period. He increased the resulting marginal capacity cost by 15 percent to reflect reserve requirements, and made adjustments for property taxes, G&A and revenue taxes.

116. Heidell also determined the marginal cost for reactive power supply based on the cost of a line capacitor project. The cost of the capacitor was unitized by dividing the capacity of the unit with adders for O&M and G&A expenses. The reactive power marginal cost is expressed in $/KVAR and assigned to rate classes that have KVAR penalty charges for customers with power factors outside of the tariff range.

117. Heidell based transmission line marginal costs (MCs) on the cost of new transmission to integrate gas-fired generation projects and recent transmission investments. He determined marginal transmission costs using two components. The first component reflects the cost of new lines to integrate new generation. The second component captures other transmission line investments, presumably for load growth and reliability, based on historical costs over the past nine years. He summed these two costs and adjusted the result for O&M, G&A, property tax, and other tax adders to compute his marginal transmission cost.

118. Heidell calculated distribution substation MCs using an estimate of the cost of constructing two projects: the Sheridan substation (at $40/KW) and the Miles City substation (at $14/KW). He based his marginal substation cost on an average of the cost of these two projects. He levelized the capital costs using a fixed charge rate and applied adders for O&M, G&A, and other taxes. He classified marginal substation cost as 100-percent capacity related and allocated

costs to each class based upon the non-coincident peaks of the Montana customer classes using Aberle's ECOS AED allocator.

119. Heidell calculated distribution MCs using the cost for distribution lines, transformers, service lines, and metering. He calculated the marginal cost of distribution lines by estimating the per-mile cost of constructing new distribution circuits in Montana. Then he converted that cost to a cost per customer using data on the number of circuits, circuit miles, and customers on the Montana system. He classified these costs as demand- and customer-related based on Aberle's ECOS minimum system study, which classified 82 percent of the distribution costs as customer-related.

120. Heidell calculated marginal line transformer costs based on the estimated cost of a new transformer. The cost is class specific and reflects a weighting of the size of the transformer used by each customer class. Line transformers were classified as demand- and customer-related, with the customer proportion based on a linear regression of line transformer size as a function of cost where the intercept of the regression line is the customer proportion. He calculated the customer portion for each class based upon the average number of customers on a line transformer.

121. Heidell stated that MDU staff provided him with the marginal cost for service lines, which apply only to residential and small commercial customers. He testified that larger commercial and industrial customers taking service at primary voltage have their own underground service line and do not require this service. Heidell estimated the marginal cost of metering based on five year averages of historical costs associated with meter reading, billing, and sales expense.

122. Heidell explained that his MCOS study used the same energy, demand, and customer allocation factors Aberle used in her ECOS study, noting that the demand and energy allocation factors reflect applicable voltage level losses. He also explained that MCOS studies do not allocate all costs, like an ECOS study, but only those associated with an increment or decrement of load. He stated that marginal costs may be either greater than or less than average costs. In fact, he noted that his MCOS study indicates that total system marginal costs, not including externalities, are about 35 percent higher than the embedded cost revenue requirement. Heidell did not find this surprising because replacement costs are usually higher than historical costs and

the MCOS study does not adjust equipment costs to reflect that used equipment typically has less value than new equipment because part of its economic life has been used up.

123. In order to annualize capital investments within his MCOS study, Heidell calculated nominal levelized fixed charge rates (LFCR) based on the capital structure and cost of capital used in the ECOS and applicable book life assumptions. LFCRs for generation, transmission and distribution investments were calculated as the annual equivalent cost of an associated capital cost divided by the initial cost. The LCFRs incorporated the annual debt and return on equity assuming the annual book depreciation for each type of investment, tax depreciation, normalization of taxes, and income taxes.

124. Heidell multiplied his marginal unit cost estimates by loss-adjusted energy and demand allocation factors at the customer class level to determine total MCs at the class level, inclusive of losses. These allocation factors were adjusted by the same demand and energy loss factors used in the ECOS. Heidell stated that if the PSC uses marginal unit costs to guide rate design, they should be adjusted for the class loss factors used in the ECOS study.

125. Heidell's MCOS study produced a marginal generation energy cost (w/o externalities) equal to $0.0436/kwh. The study also indicated that during coincident peak hours, marginal generation demand costs equal $9.10/KW-month, marginal transmission demand costs are $4.88/KW-month, and marginal substation demand costs are $1.47/KW-month. He explained that he allocated marginal generation energy costs to customer classes based on loss adjusted sales and marginal generation, transmission, and substation demand costs according to Aberle's AED allocator. He allocated distribution demand-related costs based on class non-coincident peaks. The table below compares the results of Heidell's MCOS study to Aberle's ECOS study:

Comparison of class-level embedded and marginal costs

Rate Class	Embedded Total (2010)	Marginal Total (2012)	Marginal / Embedded
Residential Rate 10	$15,079,800	$19,542,054	30%
Small General Rate 20	8,620,814	11,730,215	36%
Irrigation Power Rate 25	349,820	467,187	34%
Large General Primary Rate 30	2,531,408	3,407,459	35%
Large General Secondary Rate 30	8,802,824	11,931,252	36%
Large General Service TOD Rate 31	687,031	933,215	36%
Contract Services Rate 35	10,277,786	14,581,157	42%
Municipal Pumping Rate 48	552,608	739,822	34%
Private Lighting Rate 52	227,369	246,828	9%
Street Lighting Company Owned Rate 41	471,893	499,788	6%
Street Lighting Municipal Owned Rate 41	81,025	101,863	26%
Total	$47,682,378	$64,180,840	35%

Encore Response Testimony

Alan Rosenberg

126. Alan Rosenberg addressed MDU's embedded and marginal cost of service studies and rate design proposals, particularly for Large General Electric Service (Rate 30).

127. Rosenberg disputed several aspects of Aberle's ECOS study. He asserted that Aberle miscalculated Factor 3, which allocates fixed wind costs, by incorrectly computing a weighted average of each class's energy (kwh) and demand (KW). He stated that because kwh and KW are not like units, Aberle's weighted average produces a meaningless figure.

128. Rosenberg contended that Aberle arbitrarily classified 80 percent of the fixed costs of wind as energy-related and the remaining 20 percent as demand-related, without providing any supporting analysis. He testified that all fixed generation costs are customarily classified as demand-related, but admitted that wind generation differs from conventional generation because it has no fuel costs, is not dispatchable, and is intermittent. However, he stated that these differences in no way imply that 80 percent of wind fixed costs are energy-related. Rosenberg contended that a more appropriate classification of fixed wind would reflect the fuel and purchased power costs that additional wind generation is expected to save, plus wind generation tax credits, as a percent of the cost of additional wind generation. Using this approach, he estimated that 32.8 percent of wind costs should be classified as energy-related, and the balance classified as demand-related. He asserted that using his 32.8/67.2 split instead of MDU's 80/20

split for classifying energy and demand costs would reduce Montana's share of fixed wind generation costs from 28.22 percent to 26.17 percent, and reduce Montana's revenue requirement by approximately $386,407.

129. Rosenberg disagreed with Aberle that her AED allocator method is widely accepted, contending instead that it is in relative disuse and that the PSC has not specifically endorsed it. He also asserted that none of the parties to the settlement in Docket No. 2007.7.79 endorsed the method. Rosenberg expressed concern that the AED allocator classified 75 percent of costs as energy-related. He asserted that in light of MDU's expected growth and need for additional capacity (exacerbated by the termination of the Big Stone project), the AED's emphasis on energy and de-emphasis on demand conveys the wrong price signal to customers and unduly penalizes classes that control their peaks.

130. Rosenberg testified that the AED method over-emphasizes energy because Aberle used a low system peak value. He noted that while Aberle used a 474 MW system peak, MDU witness Stomberg testified that MDU's 2010 summer peak is forecast to be 525 MW and MDU's IRP forecast a 2010 summer peak of 539.5 MW. He concluded that Aberle's 474 MW peak is unrealistic and distorts cost responsibility and cost causation. He added that he calculated a 127 MW Montana coincident peak using the hourly loads supplied in data response EC-113, while Aberle used 114.9 MW as Montana's coincident peak.

131. Rosenberg developed an AED allocator that: 1) attributed 24.26 percent of the system summer peak demand to Montana (similar to Aberle); 2) corrected Aberle's mathematical errors in her Factor 3 calculation; 3) assumed a Montana coincident peak demand of 127,365 KW; and 4) assumed a 32.8/67.2 energy/demand classification for wind. With his revised AED allocator, 41,410 KW would be allocated on class excess demand (compared with Aberle's 28,982 KW), 67.5 percent of conventional generation and transmission fixed costs would be allocated on energy, and over 78 percent of wind costs would be allocated on an energy basis.

132. Rosenberg opposed using the AED allocation method in this case, asserting that the method ignores class-level coincident peak demands and leads to price signals that frustrate efficiency. He contended that some type of coincident peak allocation method would be more appropriate. He said he would accept the use of a 12 CP method (as recommended by Mulkern) for the allocation of transmission plant costs, but objected to weighting all months equally because the peak in some months will not approach the system peak, and will have hardly any

influence on capacity requirements. He recommended a three summer (July-September)/two winter (January-December) coincident peak method to allocate demand-related costs, which would reduce Montana's share of demand-related generation costs from 24.765 percent to 24.356 percent. He presented modified ECOS study results that incorporate his recommended 5CP methods. Rosenberg contended these results more accurately reflect cost causation than the AED studies.

133. Rosenberg contended that MDU witness Heidell made two significant errors in his MCOS study. First, he asserted that Heidell overestimated marginal costs by using questionable and uncertain forecasts far into the future. Second, he argued that Heidell inappropriately multiplied marginal generation and transmission demand-related costs by the AED "demands" from Aberle's ECOS study.

134. Rosenberg asserted that Heidell's annualized $41.88/MWh marginal energy cost is well above the average MISO Day Ahead Price of $27.61 per MWh (for period 11/09-10/10). Rosenberg contended that the MISO Day Ahead Price must serve as a ceiling for MDU's marginal costs because if MDU's marginal costs were higher it would be more economical to buy from the market.

135. Rosenberg said Heidell's decision to estimate marginal energy costs over an eight year period reflects a misinterpretation of ARM 38.5.176. According to Rosenberg, that rule actually requires the MCOS study be computed in dollars two years beyond January 1st of the year the filing is submitted. In other words, in this case the rule requires costs stated in 2012 dollars, but does not specify 2012 as the year in which costs must be measured, as Heidell appeared to believe.

136. Rosenberg testified that instead of using actual data or estimates for the near future, Heidell used estimates of production costs for the period of 2012-2019 in his MCOS study. Rosenberg found these estimates unreasonable. He noted that Heidell's model produced an average variable production cost of $32.01/MWh, which is 36 percent greater than MDU's test year average variable production cost. He said Heidell estimated even higher production costs in the outer years of his study. Rosenberg maintained that forecasting costs that far out in the future unnecessarily adds uncertainty. He asserted that that the PROSYM model Heidell used to estimate production costs is capable of estimating costs for a one or two year time horizon and it is not necessary to run the model over an 8-year time horizon. He contended that no

authoritative text on ratemaking that he is aware of recommends estimating marginal energy based on long range forecasts and, hence, Heidell's approach is not consistent with economic theory.

137. Rosenberg stated that even if Heidell's marginal energy cost estimates were theoretically defensible, using inflated marginal costs would disrupt the goal of setting rates based on cost causation because artificially exaggerating the energy component diminishes the role of demand and sends poor price signals. Rosenberg also testified that Heidell's two MCOS studies with CO_2 externality costs result in highly speculative prices that are unlikely to materialize into real costs by 2012. Rosenberg said that including these hypothetical costs exacerbates the problem of inflated energy costs.

138. Rosenberg modified Heidell's MCOS study by using $25.57 per MWh as the marginal cost of energy and calculating generation capacity costs using each class's coincident peak demand.

139. Rosenberg emphasized the importance of setting rates based on actual cost. He said that confronting customers with price signals that convey the consequences of their consumption decisions in turn provides correct signals to the utility about the need for new investment and furthers the goals of stability, conservation and efficiency. He agreed with Aberle's decision to rely on the ECOS study for revenue allocation, although he did not agree with some of the particulars of her study. He also agreed that if MDU is granted a 13 percent overall revenue increase, no class should get a revenue decrease. However, he said that if the PSC grants MDU an increase that is significantly less, for example less than 7 percent, than if the cost study indicates decreases are warranted for some classes they should be implemented.

140. Rosenberg disagreed with Aberle's 14.5 percent cap on revenue increases for any class, noting that 14.5 percent is barely 1.1 times the system average of 13.0 percent, and caps are usually in the order of 1.5 to 2.0 times the system average. He asserted that if the system average increase is granted at 13.05 percent, the cap should be 1.75 times that, or 22.83 percent. For a system increase between 5 percent and 7 percent he recommended a cap 2.0 times the system average. For a system increase of 4.5 percent or less he recommended a 10 percent cap.

141. Rosenberg proposed class revenue requirements that assume the PSC grants MDU full revenue relief and that reflect Aberle's ECOS study with his corrected AED allocator. His proposals also reflect the following: 1) any class that requires a decrease from current rates to be

brought to COS is not allocated any portion of the increase; 2) Rate 35 is adjusted to COS with the exception that it does not receive a decrease as long as the system increase is 13.05 percent; 3) revenues from all classes other than Rate 35 are increased as necessary to bring them to COS, but not by more than 22.83 percent; 4) any revenue shortfall from applying the cap is reallocated to all classes that are not capped in proportion to their COS; and 5) if all classes, other than the ones capped at 22.83 percent, are in need of a decrease in order to reach COS, the shortfall is allocated to all those classes in proportion to their COS, so as to minimize any distortion.

142. Rosenberg testified that his preferred allocation method for MDU in this rate case would be based on multiple coincident peaks. Rosenberg's recommended spread of the increase based on his preferred study is shown in Ex. AER-8. Rosenberg stated that should the PSC not follow his recommendation of relying solely on the ECOS study, he would recommend the PSC use the MCOS study to allocate the production revenue requirement, but still use the ECOS study to allocate the transmission and distribution revenue requirement. The results of this type of allocation are summarized in Ex. AER-9. Rosenberg cited a recent PSC docket for a NWE case (Docket No. D2009.9.129) in which all of the major parties in the case agreed that an ECOS analysis is the most appropriate benchmark for determining class responsibility and revenue requirements for transmission, distribution, and customer costs. Rosenberg supported that approach, noting that the *NARUC Electric Utility Cost Allocation Manual* states "...the determination of marginal costs for these [transmission, distribution, and customer costs] functions, and especially distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort." For comparison purposes, Rosenberg provided class revenues based solely on a MCOS study in Ex. AER-10.

143. Rosenberg testified that he has concerns with MDU's proposed rate design for Large General Service Rate 30 in particular. Rosenberg stated that, according to the ECOS study, about one-third of the total cost for Large General Service is comprised of energy-related costs, predominantly fuel and purchased power. But, according to Rosenberg, Aberle advocated collecting about three-quarters of the revenue through the fuel charge plus the energy charge. Rosenberg disagreed with this approach because: 1) it penalizes customers with high load factors that use energy at a relatively constant rate;, 2) it does not incent customers to control peak demands, and 3) it means MDU would recover much of its fixed costs with variable charges, so

if Large General Service usage turns out to be significantly greater than test year levels, MDU will over-earn.

144. Rosenberg offered a different rate design for Rate 30. First, he set customer charges for the Primary and Secondary customers at $185/month and $70/month, respectively. He noted that although these proposed charges are 1½ to 2 times that proposed by Aberle, the customer charges would still only recover about 2 percent of the total revenue target. Next, he set the energy rate for the Primary class at $0.0100 per kwh, which means that the energy rate, plus the base Fuel and Purchased Power charge, will be above the average marginal energy cost. He stated that although the total energy rate would be more than the embedded energy cost with his rate design, the difference would be smaller than it would be with Aberle's proposal. He also eliminated the seasonal differential in the energy charge, retained Aberle's $1.00 differential in the demand charge between winter and summer months, and included a differential in the demand charge for Primary and Secondary customers in the amount of $0.23/KW per month to reflect higher losses for lower voltage customers and the additional facilities that are used to provide Secondary service but not Primary service. He provided his preferred rate design for Rate 30 and also provided an alternative rate design that assumed no increase in Rate 30 class revenues.

145. Rosenberg recommended rejecting MDU's proposed transmission cost recovery rider (Rate 57) and renewable resource rider (Rate 56) because they are vague, unnecessary, bad regulatory policy, and poorly designed. He believes the riders are vague because Rate 56 does not specify what qualifies as a renewable resource or how the costs of that investment will be calculated, and Rate 57 states that it includes facilities constructed to improve capacity or reliability, but it does not explain whether that is a necessary condition or a sufficient condition, or contain guidelines for determining the purpose of the new transmission facility. Rosenberg believes the proposed riders appear to be crafted to adjust automatically, much like a fuel and purchased power adjustment mechanism (Rate 58). Rosenberg stated that Rate 58 is an exception to traditional regulation because of three distinguishing characteristics: 1) fuel costs are material, representing over 30 percent of the requested revenue requirement in the test year, 2) fuel costs can be highly variable, and 3) fuel costs, to a large extent, can be outside the control of the utility. He asserted that MDU has not shown that the costs associated with the proposed riders are substantial, highly variable, and outside MDU's control. Therefore, he finds the riders

unnecessary. He asserted that the riders make for bad regulatory policy because stakeholders cannot challenge the legitimacy, need, or accuracy of the costs in question, and because the riders focus on one single element of the cost structure while ignoring other changes in costs, investment, and revenue. Rosenberg stated that the riders are structured to recover costs through a uniform cents-per-kwh charge applicable to all retail energy sold, without taking into account that the retail classes have different load factors, different coincidence factors, and different loss factors. Rosenberg also expressed concern that neither transmission nor renewable resource costs are energy-related, yet will be recovered on the basis of energy consumption.

MCC Response Testimony

John W. Wilson

146. John Wilson addressed MDU's cost of service study. He contended that MDU's ECOS study contains faulty classification and allocation procedures that result in residential and small business customers being charged more than their fair share of MDU's revenue requirements. He disputed MDU's use of the AED cost allocation method for generation and transmission costs, and the minimum system approach for classifying distribution costs.

147. Aberle's ECOS study uses an AED allocation method to classify and allocate generation costs. Wilson disputed the reasonableness of the AED allocation method for generation costs because it uses NCP demand rather than CP demand, and results in a cost allocation that closely resembles an allocation based solely on monthly coincident peak demands, without giving any consideration to energy consumption. He contended that generation plant investment levels are related to energy consumption and monthly coincident peak demands, but not individual class NCP load. Because MDU's ECOS study results in an allocation that so closely resembles an allocation based solely on monthly coincident peak demands, Wilson asserted that the study distributes benefits so that classes with peaks coincident with the system (such as high load factor industrials) are assigned a smaller share of total system costs, and classes with high diversity (such as the residential class) are assigned a larger portion of the total costs. He contended that MDU's approach fails to properly classify generation costs on the basis of both demand and energy.

148. Wilson asserted that in allocating generation costs it is increasingly recognized that hours other than the peak hour are critical from a system planning perspective, and regulators and utilities have moved toward multiple peak allocation methods as well as the classification of

generation plant costs between energy and demand responsibility. Wilson said two methods that classify generation costs as both demand and energy-related are the Average and Peak method and the Equivalent Peaker method. The Average and Peak method combines each class's average demand with its peak demand to develop a class allocator. He said that with this allocator the system load factor determines the percentage of plant costs considered energy-related and the remainder (1-load factor) is considered demand-related and allocated in proportion to each class's CP demand. The Equivalent Peaker method uses the ratio of the cost of peaking capacity per unit of load (KW) to the utility's total capacity cost per unit of load to determine the percentage of generation plant costs classified as demand, with the remainder classified as energy.

149. Wilson contended that a large portion of MDU's base load and renewable generation plant investment is driven by energy requirements, and recommended an allocation method that incorporates a balanced energy and demand weighting into the classification of generation costs. He said that in this case, MDU's cost allocation would have been more reasonable if its generation plant allocator had used 12-CP demand instead of excess demand to allocate the portion of the generation plant costs that were not classified as energy. The 12-CP method is based on the combination of the twelve monthly system coincident peaks, rather than on the basis of contribution to the single highest hourly demand during the year. It attempts to capture some of the relevant cost-causative attributes of the monthly loads that a utility must serve and recognizes that generation and transmission capacity is installed not only to meet coincident peak demand, but also to maintain system reliability during all months of the year. Wilson used the 12-CP method in his suggested modification of MDU's COS study.

150. Wilson raised similar concerns with MDU's use of the AED allocator to classify and allocate transmission costs. He asserted that utilities use base load plants and associated transmission grids to produce, coordinate, and deliver energy around-the-clock as well as to satisfy customers' average level of demand. He testified that a portion of MDU's high capital costs are justified by energy consumption and not by the coincident or non-coincident demands of the various classes.

151. Wilson contended that transmission costs should also be classified as both demand and energy, and asserted that a cost-minimizing utility maintains a mix of generating resources to meet varying demands and reduce overall production costs, thereby lowering the cost of both

capacity and energy. Ideally, a utility will use its transmission grid to achieve optimal dispatch and reduce energy costs, and Wilson believes the classification of transmission costs should recognize that. Wilson stated that the same is true for large transmission level substations. The transmission substations are typically needed on integrated systems that efficiently tie remote base load and wind-powered plants to network load centers, but their costs are not primarily attributable to the cost of peak demand. Wilson testified that transmission investment and expense is clearly related to both the transport and network integration of less costly energy from base load plants to support both demand and energy needs, and as such, should be assigned to both energy and demand classifications. Wilson believes that if MDU should use the AED allocator in its classification and allocation of costs, it would be more appropriate to use 12-CP demand within the allocator as opposed to NCP demand.

152. To illustrate the resemblance between MDU's AED allocation method and an allocation based solely on monthly coincident peak demands, Wilson provided the following table, which shows the percentage of costs allocated to each major class under MDU's AED allocator, a coincident peak demand allocator and an energy-only allocator:

Share of costs allocated to customer classes with different allocators

Class	Average and Excess %	Coincident Demand %	Energy %
Residential	26.91%	26.37%	23.52%
Small General Service	18.51%	19.33%	16.03%
Large General Service	51.65%	51.39%	57.99%

153. Wilson also contested how MDU classified and allocated distribution costs. In particular, Wilson faulted MDU's decision to classify nearly 80 percent of its distribution costs as customer-related, and none as energy-related. MDU used a "minimum distribution system" (MDS) method to determine the customer-related portion of distribution plant costs, which it then allocated to customer classes on the basis of the number of customers in each rate class. Since the residential rate class has the largest number of customers, it gets assigned a high percentage of distribution plant costs.

154. The MDS methodology involves estimating the cost of a theoretical system of minimum-sized plant capable of serving a minimum (i.e. near zero) load, but still connecting all customers. But Wilson contended that MDU used contemporary standard equipment and conventional system construction designed to meet today's actual and anticipated loads in

costing out its estimate of a minimum-size system, resulting in substantial costs that are clearly load related. As an example, Wilson pointed to MDU's response to data request PSC-001, wherein MDU indicated that they had used expensive pad mounted transformer equipment to estimate minimum distribution system costs. Consequently, MDU considered 76 percent of the costs in Account 368-Transformers customer-related. Wilson contended that 57 percent of those costs would be customer-related if less costly line transformers were used. According to Wilson the total cost of a theoretical minimum system designed to serve a near zero load would be no more than 10-25 percent of actual distribution costs.

155. Wilson contended that investments in distribution lines and related equipment contribute to an integrated power delivery network, and, therefore, are not customer-specific investments that are causally attributable to customer counts. To support his view he cited from Bonbright's *Principles of Public Utility Rates*, which reports a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system, likely because such calculations fail to consider the density of customers in an area. Bonbright also cites a regression analysis (Lessels, 1980), in which no statistical association was found between distribution costs and number of customers. Wilson commented that while NCP demand is an appropriate cost allocator for distribution facilities that are installed to meet lower voltages in local areas, a 12-CP method is likely to be a more appropriate choice to allocate primary distribution costs that are driven by more broadly based regional requirements.

156. Wilson summarized his alternative cost of service study in Ex. JWW-10. He classified generation and transmission costs as 50 percent energy-related and 50 percent demand-related, and allocated the energy portion in proportion to class energy loads and the demand-related costs in proportion to average monthly coincident peak demands (12 CP). Similarly, he classified distribution costs 50 percent energy-related and 50 percent demand-related, and allocated the energy-related costs in proportion to class energy loads and the demand-related costs in proportion to non-coincident peak demand. He also made several other changes in his COS study, including 1) reallocating revenue credits (sales for resale and margin sharing) and A&G expenses on the basis of retail revenues and 2) allocated materials and supplies on the basis of total plant rather than on the basis of only production, transmission and distribution.

157. Wilson testified that if a COS study has correctly attributed the proper portion of total costs to each rate class, an appropriate rate structure would result in equal rates of return for each

class. Wilson contended MDU's COS study has under-allocated costs to high load factor customers, and has over-allocated costs to smaller, lower load factor customers. Wilson stated that if MDU's plant costs are reallocated to more properly reflect energy responsibility for plant investment the calculated rates of return for customer classes change substantially, and the results indicate that residential customer rates produce returns that are well above the system average:

Indicated rates of return (before adjustments)

Rate Class	MDU's COS Study	Wilson's COS Study
Total Company	5.157%	5.157%
Residential	4.127%	8.791%
Small General	4.859%	5.729%
Large General	5.904%	3.148%
Mun. Pumping	-0.328%	-0.995%
Lighting	9.077%	9.667%

158. Wilson questioned the efficiency of MDU's proposed rate design. He noted that small general service (Rate 20) and residential (Rate 10) customers would pay higher rates in the summer months than in the winter months, while large general service (Rate 30) and contract (Rate 35) customers would pay the same energy rates in all months. For example, large general service customers taking service at primary voltage would pay $0.045/kwh in summer months, but small general service subscribers, also taking voltage at primary voltage, would pay $0.067/kwh. Residential customers, who do not have demand charges, would pay $0.096/kwh. Wilson questioned the reasonableness of these widely varying prices.

159. Wilson criticized MDU's proposal to increase monthly charges for all customer classes while reducing the per kwh energy charge for large general service customers in the summer months. He said that increasing customer charges and reducing peak season energy charges is not a sensible rate design change for a utility that is concerned about improving price signals to promote efficient energy consumption because per customer charges play no role in efficiency. He added that MDU's rate design proposals send customers inconsistent price signals for incremental energy consumption. As an example he noted that residential customers would be told that incremental cost of an additional kwh is 9.6¢ in summer months, while large contract service customers would be told the cost of an additional kwh is 3.9¢. Wilson contended that, in fact, at any particular time the incremental cost an additional kwh is exactly the same regardless

of which customer's load is varying. Wilson believes incremental energy rates are the strongest energy conservation tool available to utilities because they allow customers to directly respond to the price signals they are receiving with regard to the cost of an increase or decrease in kwh consumption. Wilson stated customers cannot respond to per-customer charges and capacity charges that are more or less fixed in the short term.

160. Wilson summarized his recommendations as follows: 1) residential rates should not be raised because MDU is already collecting all costs associated with serving these customers; 2) flat monthly customer charges should not be raised for any customer class, because they do not contribute to efficient energy consumption decisions; 3) any increase in rates for non-residential classes should be imposed through energy charges; and 4) to the extent that seasonal energy rate differentials are appropriate, they should be adopted for all customer classes, and the summer energy charge reductions that MDU proposes for large general service customers should not be approved.

161. Wilson concluded by addressing MDU's proposed tracker (Rate 58) and rider rates (Riders 56 and 57). He stated that trackers and cost adjustment riders offer only one advantage – they provide prompt and more frequent adjustment of electric utility rate levels in response to changes in the costs on which they are focused than is possible in complete rate investigations. In contrast, he identified several disadvantages including: 1) rate adjustments may go in one direction while the utility's total costs are moving in the other direction, since the adjustments are based upon consideration of only some rather than all of the utility's costs; 2) partial cost adjustment procedures may be biased to register changes in those cost elements that are most subject to increase, without registering offsetting factors, such as productivity improvements, that reduce total costs; and 3) trackers may tend to weaken or distort incentives for a utility to supply electricity at a minimum cost because of the opportunity to change rate levels very quickly in response to certain cost changes between rate cases, and pass gains or losses on to ratepayers rather than shareholders.

162. Regarding Rate 58, MDU proposed adding MISO administration charges to fuel and purchased power costs and to change the split of wholesale sales margins by reducing the base value to zero and by allocating 15 percent (rather than 10 percent) to the benefit of MDU shareholders. Wilson believes there is no more reason to include MISO administrative charges than any other administrative costs in the tracker, and believes that doing so would eliminate

MDU's financial incentive to attempt to minimize these costs. He recommended rejecting MDU's proposed changes to Rate 58 and maintaining the balanced 90/10 split for both margin sharing and changes in fuel and purchased power costs.

163. Wilson finds the proposed new riders for transmission and renewable resource cost recovery (Rates 56 and 57) unusual and troubling from a traditional regulatory perspective. The proposed new riders would allow transmission and renewable resource cost increases without traditional general rate case consideration and would allow for immediate rate adjustments. He said such adjustments would not take account for associated cost offsets that may occur because of these investments. Likewise, transmission investment, which is often closely integrated with a substitute for generation costs, would be passed onto consumers in rate adjustments without considering related generation cost offsets. Wilson recommended rejecting these proposed new riders.

MDU Rebuttal Testimony

Tamie Aberle

164. Aberle agreed with Rosenberg that generation-related costs should be classified as demand-related, but disagreed with his proposal to allocate costs based on a 5-month coincident peak demand allocator (January, July, August, September, and December). Aberle asserted that the AED allocation factor is more reasonable because, while a portion of MDU's generating facilities are associated primarily with serving peak demands, the majority of the generating capacity is baseload associated with serving average demands throughout the year. She contended that in MDU's last electric rate case Encore's consultant proposed and endorsed the AED method for allocating generation and transmission costs.

165. She disagreed with Wilson's approach of classifying 50 percent of generation costs as energy-related and 50 percent demand-related, and allocating the energy-related costs on the basis of energy sales. She contended that the AED approach recognizes the energy use of each class without recovering demand-related costs through an energy component.

166. With respect to transmission function costs, Aberle acknowledged that classifying those costs as demand-related using a 12-CP allocator, as Rosenberg recommends, is an acceptable alternative to MDU's AED method. She disagreed with Wilson, who recommended classifying transmission costs 50 percent energy-related and 50 percent demand-related. She asserted that

transmission costs are fixed and it is not appropriate to recover them through a variable component.

167. Similarly, Aberle objected to Wilson's proposal to classify 50 percent of distribution function costs as energy-related and 50 percent demand-related. She maintained that there is no basis for classifying distribution costs as energy-related or allocating those costs on the basis of energy use. In support of her position, she points to NARUC's *Electric Utility Cost Allocation Manual*, which states:

> ...all costs of services can be identified as energy-related, demand-related or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.[1/]

168. Aberle testified that MDU followed the preferred classification of distribution plant and distribution expenses discussed in the NARUC manual.

169. On page 6 of her rebuttal testimony, Aberle compares the effect of Rosenberg's and Wilson's recommended cost of service approaches to MDU's. The table below summarizes her comparison:

	Revenue @ current rates [1]	Cost of Service		
		MDU [2]	MCC [3]	Encore [4]
Residential Service	12,898,287	15,079,800	12,893,150	17,701,947
Small General Service	7,825,066	8,970,634	8,677,518	9,483,160
Large General Service	20,283,319	22,299,049	24,766,134	19,509,514
Municipal Pumping	381,466	552,608	588,311	543,278
Lighting	791,659	780,287	757,236	489,492
Total Montana Electric	42,179,797	47,682,378	47,682,349	47,727,391

1 Statement H

2 Statement L

3 Wilson cost of service workpapers

4 Rosenberg Exhibit AER-8

170. Aberle observed that Wilson's cost of service approach shifts revenue responsibility away from smaller energy use residential and small general service customers to the large energy

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[1/] *Electric Utility Cost Allocation Manual*. National Association of Regulatory Utility Commissioners, January 1992.

use large general service and contract service customers. In contrast, Rosenberg's approach shifts revenue responsibility away from the large general service and contract customers to the residential and small general service customers. She added that Wilson's classification approach shifts about $19 million in cost responsibility from demand and customer components to energy components, compared to MDU's cost of service methods, and results in classifying about 70 percent of MDU's revenue requirement as energy-related. She contended that this result is illogical given the capital intensive nature of the electric system's infrastructure and the obligation to provide safe, reliable service. She also testified that Wilson's cost of service methods shift about $6 million in rate base from the residential and small general service customer classes primarily to large general service classes, resulting in a negative rate base customer component for the Residential, Small General Service and Irrigation service classes. She said that outcome is not credible because those classes represent 98 percent of all MDU's Montana customers. Aberle concludes that the PSC should consider MDU's cost of service study a reasonable approach to determining class revenue responsibilities and establishing pricing components.

171. Aberle acknowledged that MDU's ECOS model contained an error in the calculation of the allocation factor applied to wind generation costs. The error resulted in slightly under-weighting the demand component in the AED allocation method.

172. With respect to rate design, Aberle testified that Rosenberg's recommendation to cap class revenue increases at 22.83 percent should be rejected as too large. She characterized MDU's 14.5-percent cap as a more balanced and gradual move toward cost of service. Aberle also disagreed with Wilson's recommendations that the PSC not increase customer charges. She contended that fixed costs should be recovered from customers in the customer charge or base rate in order to minimize intra-class subsidies. She added that reduced energy use due to conservation should not lead to unrecovered fixed costs.

173. Finally, Aberle renewed her support for the Renewable Resource Cost Recovery and Transmission Recovery riders. She maintained that the purpose of these riders is to allow the Company a way to recover primarily capital costs that are outside the Company's complete control without going through the expensive and lengthy rate case process.

James Heidell

174. Heidell filed rebuttal testimony addressing Rosenberg's concerns regarding MDU's marginal cost of service study. Heidell also updated MDU's marginal cost study with respect to distribution capacity costs.

175. Heidell agreed with Rosenberg that coincident peak demands are typically used in marginal cost studies to allocate demand-related generation, transmission, and substation costs. He acknowledged that it is appropriate to allocate demand-related generation and transmission costs differently in marginal and embedded cost studies, because their focuses are different. Marginal cost studies focus on the long-run marginal cost of a change in demand and efficient use of generation and transmission resources. Embedded cost studies focus on a number of objectives, including efficiency and equity.

176. In his original marginal cost study, Heidell allocated generation and transmission costs using the AED allocators MDU developed for its embedded cost of service study. In his rebuttal testimony he contended that allocating those costs using coincident peak demands has the effect of changing total marginal demand-related costs and total system marginal costs, and changes the amount of costs allocated to each rate class. However, these changes have no effect on MDU's proposed rates because MDU does not rely on the results of its marginal cost study to design rates in this case. He added that because marginal costs are independent of MDU's revenue requirement, allocating demand-related generation and transmission marginal costs using coincident peak demands does not affect the revenue requirement in this case.

177. Heidell explained that MDU prepared a marginal cost study in this case to satisfy PSC administrative rules and to inform rate design. He stated that if the PSC were to use the marginal cost study to establish rate class revenue responsibilities it would first be necessary to reconcile the marginal costs to the embedded costs, since it is typical for long-run system marginal costs to exceed the revenue requirement. He noted that, commonly, this is done through an equal percentage adjustment.

178. With respect to marginal distribution costs, Heidell explained that the discovery process revealed outdated distribution cost data. Current data reflects higher per-mile costs for underground and overhead circuits and more accurate customer counts. He stated that updating distribution cost data has minor impacts on the overall cost study results, a 0.4 percent increase

in total marginal costs. He stated that this change in his marginal cost study does not affect MDU's revenue requirement or rate design proposals.

179. Heidell provided several tables summarizing his modified marginal cost study on pages 8-10 of his testimony. The tables show that the above described modifications slightly increase the total marginal cost of serving the residential and small business rate classes and slightly reduce the total marginal cost of serving large commercial and industrial rate classes.

180. Heidell disagreed with Rosenberg's recommendation to use five monthly coincident peaks (three summer and two winter months) to allocate demand-related generation and transmission marginal costs. Heidell recommended using 12 monthly coincident peaks (12-CP) for transmission and transmission substation costs and the system coincident peak (1-CP) for generation costs. He testified that 1-CP should be used for generation because that approach is consistent with MDU's expectation that it will remain a summer peaking utility.

181. Heidell acknowledged that MDU's 2009 system peak demand appears to be atypical. However, he rejected the idea of trying to adjust that system peak using a load factor approach, as suggested by Rosenberg, because the data needed to adjust each rate class's peak were not readily available. He asserted approaches to weather-adjusting coincident peak demands should be studied for future cases if the PSC intends to rely on marginal costs for determining class revenue responsibility.

182. Heidell testified that allocating demand-related transmission and substation costs on the basis of 12-CP demand is reasonable given that 2009 was an atypical year and MISO uses a 12-CP allocator.

183. Heidell agreed with Rosenberg that the PSC could practically determine class revenue responsibility for transmission and distribution function costs based on embedded costs and generation function costs based on marginal costs, noting that there are virtually an infinite number of ways to spread the revenue requirement. However, he contended that Rosenberg's revenue allocation proposal does not promote efficiency because when marginal costs are reconciled to the revenue requirement, marginal cost-based prices are diluted. The result is a mix of embedded and marginal cost logic that obscures both short-run and long-run marginal costs.

184. Heidell defended his marginal energy cost estimates and disputed Rosenberg's contention that the definition of long-run marginal cost is incompatible with marginal energy

cost. According to Heidell, in the electric utility industry long-run marginal energy costs are typically calculated over multiple years for various applications, such as avoided cost analyses and general rate cases. These cost estimates are needed to evaluate trade-offs between different types of generation investments and the cost-effectiveness of conservation. His long-run marginal energy costs reflect the change in hourly dispatch costs due to an hourly increment in load over an eight year period. He asserted that it is appropriate to consider multiple years when estimating marginal energy costs if the context is a study of long-run marginal costs. He added that it would be inconsistent to mix short-term marginal energy costs with long-term marginal generation capacity, transmission, and distribution costs. He contended that his approach to estimating marginal energy costs is reflected in NARUC's *Electric Utility Cost Allocation Manual.*

185. Heidell disputed Rosenberg's testimony that designing rates based on long-run marginal energy costs would frustrate energy conservation. While Rosenberg suggested that investment in electric cars would be frustrated by prices reflecting long-run marginal energy cost, Heidell countered that consumers that are deciding whether to make long-term investments in electric cars or other conservation should consider long-term marginal energy costs. He adds that, in theory, designing rates based on long-run marginal costs provides customers with an appropriate price signal for evaluating investments that involve a trade-off of higher initial costs with lower reoccurring costs.

186. Heidell also disagreed with Rosenberg that designing rates to reflect long-run marginal energy costs would cause customers to pay twice due to the fuel and purchased power adjustment clause. Heidell pointed out that incorporating marginal costs into rate design influences how the revenue requirement is recovered but does not change either the total revenue requirement or the share of the revenue requirement allocated to each class. He also noted that the fuel and purchased power adjustment clause only recovers the difference between actual fuel costs and the expected fuel costs reflected in the revenue requirement.

187. Finally, Heidell explained that MDU provided marginal cost studies that include CO2 externality costs for informational purposes and the Company did not recommend using those studies to establish customer class revenue responsibility or rate design. However, Heidell disagreed with Rosenberg that using those marginal cost studies would increase rates. He reiterated that the marginal cost study does not impact the revenue requirement. He said that if

the PSC used those marginal cost studies in designing rates, energy rate components could increase but other rate components would decrease so that the total revenue would remain the same. He noted that adjusting rate components can affect individual customers within a rate class.

Darcy J. Neigum

188. Neigum said the 80-percent energy, 20-percent demand classification factor split that was originally assigned by MDU to its wind projects remains valid. He said that, based on actual operating data, MDU anticipates that both Diamond Willow and Cedar Hills will be assigned at least a 20 percent capacity allocation factor by MISO when it completes its generator-by-generator analysis.

189. Neigum did not agree with Rosenberg's calculation of a 32.8-percent energy, 67.2-percent demand split because, depending on the forecast for future energy and fuel prices and the amount of accumulated depreciation, Rosenberg's methodology could vary significantly over time and is not an accurate means to allocate the demand allocation split for wind investments.

190. According to Neigum, Rosenberg estimated the fuel savings associated with the Diamond Willow expansion and Cedar Hills but did not account for the fuel savings associated with the original Diamond Willow project. Thus, Neigum said the energy savings amount used by Rosenberg does not match up with the total revenue requirement that he used in his calculation.

191. Regarding MDU's proposed transmission cost recovery rider and Renewable Resource Rider, Neigum disagreed with Wilson's argument that the proposed riders do not have any offsets for likely reductions in other investment costs that are displaced by facilities whose costs are tracked. He noted that in the case of the Mandan Junction Substation there is no other substation that will be retired when Mandan Junction is placed into service. Neigum said the Diamond Willow and Cedar Hills wind projects are used to meet customer energy requirements that MDU would otherwise have purchased from the MISO Energy Market or generated from available MDU generation. He said the offsetting benefits of the renewable investments are passed through to the customer under the fuel and purchased power tracking adjustment or directly under the Renewable Resource Rider. Neigum asserted that transmission investments and tariff costs can provide direct benefits to customers in the form of congestion relief which

reduces the amount of fuel and purchased power that MDU would otherwise have to purchase. The corresponding savings flow back through the fuel and purchased power tracking adjustment.

192. Neigum did not agree with Wilson's contention that the cost trackers proposed by MDU in this docket are not optimal because they weaken and distort the incentives for cost minimization and they fail to recognize offsets to the costs being tracked. He contended the proposed riders would aid in avoiding single issue rate cases and they are only used with qualifying projects and costs as a temporary cost recovery mechanism until the next general rate case.

Encore Cross-Intervenor Response Testimony

Alan Rosenberg

193. Rosenberg objected to Wilson's "corrected" allocated cost of service study as having no basis in cost causation principles and as an unsupportable, transparent effort by Wilson to arrive at the conclusion that the residential customer class should not share in any rate increase. Rosenberg disagreed with Wilson's rejection of MDU's AED cost allocation method. He criticized Wilson's rationale for rejecting the AED method because its results are similar to those obtained by the CP demand allocation method. Rosenberg argued that if a widely accepted cost allocation method produces similar results to another reputable method, then it should be viewed as corroboration of the cost allocation method's results, not as a reason for rejection. Rosenberg contended that Wilson used incomplete and faulty information when presenting a comparison of cost allocation factors. Rosenberg countered with his own comparison of various allocators (AED, 5 CP, Wilson's, and pure energy) that showed the results of Wilson's method are very similar to those of the pure energy allocator.

194. Rosenberg pointed out that Wilson identified the "Average and Peak" and the "Equivalent Peaker" methods as methods that could be used to allocate generation plant costs, but Wilson did not use either of those allocation methods in his "corrected" study. Instead, according to Rosenberg, Wilson arbitrarily allocated generation plant by allocating 50 percent of plant on an energy basis and 50 percent on the average of the 12 coincident peaks. Rosenberg said Wilson justified his 50/50 demand/energy split by citing the legitimate capital substitution theory of cost classification and allocation; however, Rosenberg argued that Wilson oversimplified the concept by focusing on one aspect of the theory that says a utility substitutes capital costs in order to save fuel costs. Rosenberg contended that a utility actually seeks to

minimize its total costs – capital and fuel – and, therefore, the justification Wilson cited for his allocation of 50 percent of generation fixed costs on energy could be easily extended to allocate 50 percent of fuel costs on a demand basis. Rosenberg said Wilson's capital substitution argument also ignored the concept of a "break-even point," which is the point at which the fuel savings of a baseload plant just begin to offset the additional capital cost. He added that the capital substitution method assumes that high load factor customers should be allocated a larger portion of the baseload plant than warranted just on the basis of peak demand, but, correspondingly, those customers should be allocated a lower than system average fuel cost per kwh.

195. Rosenberg contended that Wilson's advocacy of his 50/50 methodology for cost allocation among customer classes is inconsistent with his acceptance of the 12-CP method for jurisdictional cost allocation. Regarding Wilson's allocation of demand-related generation fixed costs on a 12-CP basis, Rosenberg argued that his own recommendation to use a 5-CP method is preferable from the cost-causation standpoint.

196. Regarding transmission plants, Rosenberg objected to Wilson's proposal to allocate 50 percent of transmission costs on an energy basis as unreasonable since no portion of transmission costs is influenced by energy usage and because Wilson failed to provide support for his argument that transmission plants must be built to connect to baseload plants.

197. Rosenberg argued that Wilson provided scant justification for his proposal to classify distribution plant as 50 percent energy/50 percent demand-related. According to Rosenberg, distribution plant costs are not energy-related at all, but rather are customer- and demand-related. Rosenberg contended that Wilson is wrong to argue that the customer component should be zero and he disagreed with Wilson's objections to MDU's use of the widely accepted minimum-size method to estimate the portion of distribution plant costs that are customer-related.

198. Rosenberg claimed that Wilson's proposal to allocate A&G expenses based on retail revenues was unsupported and inappropriate because there are more relevant factors than revenues and MDU's approach is more consistent with regulatory guidelines.

199. Rosenberg presented a cost of service study he prepared that he said reflects Wilson's testimony on a customer component for distribution plant and is based on Wilson's Ex. JWW-10 with some modifications to eliminate what Rosenberg alleged to be errors by Wilson. (See Ex. AER-13.) According to Rosenberg, a comparison of this study's results to MDU's cost study in

this docket implies that rates for the Large General Service class are too high in both studies. Rosenberg ran the same study model again, but with generation plant allocated 100 percent to demand, which Rosenberg said is more conventional than Wilson's 50/50 method. (See Ex. AER-14.) Rosenberg argued that this cost of service study is reasonable and produces the most favorable results for residential and small general service customers, while showing that large customers should receive a smaller than average increase and should receive decreases if the result of this proceeding is a small enough overall rate increase. Rosenberg presented yet one more variation on Wilson's cost study model, which he termed a proxy cap-sub study (Ex. AER-15), that allocated 15 percent of generation fixed costs on the basis of total energy consumption as a proxy for allocating 50 percent on the basis of energy up to the break-even point. He said this study produced results similar to those in Ex. AER-14.

200. Regarding revenue distribution and Wilson's opinion that equal rates of return for each class should result from a cost of service study that correctly apportions total costs to each rate class, Rosenberg agreed, but noted that deference should be given to cost studies that are based on widely accepted methods and that the recommendations he made in his direct testimony for moderating rate increases are reasonable.

201. Rosenberg disagreed with Wilson's rate design proposals. First, regarding Wilson's recommendation that customer charges not be increased, he argued the result would be to unfairly overcharge large customers via demand and/or energy charges for any under-recovery of customer-related costs. He added that, even if one accepts Wilson's argument that under-recovery of the customer charge is needed to raise energy charges up to a sufficient level, the evidence in this docket implies that energy charges for the Large General Service class should be significantly reduced, not increased. For the same reason, Rosenberg disagreed with Wilson's recommendation that non-residential energy charges be increased if rate increases are in order for those customer classes. Finally, Rosenberg opposed Wilson's recommendation that the Commission not approve MDU's proposal to reduce summer energy charges for Large General Service customers. In response to Wilson's argument that the MDU proposal is unfair because the marginal cost at any specific time does not differ among customer classes, Rosenberg argued that classes with more concentrated usage in the higher cost periods have higher average marginal costs and, because the residential class does not pay demand charges, its energy charge must be set at a level to recover both demand- and energy-related costs. Rosenberg reiterated his

position that the current summer rates, and to a lesser degree the winter rates, for the large customers in the Rate 30 and Rate 35 classes are too high in relation to marginal cost and should be reduced.

Summary of Stipulation

202. MDU, MCC and Encore submitted a Stipulation that all parties agreed to as a fair and equitable resolution of the issues in this docket and several pending Fuel and Purchased Power Tracking dockets. A copy of the Stipulation without its appendices is attached to this Order as Attachment A. The terms of the proposed Stipulation are summarized as follows:

a. MDU will be granted an overall rate increase of $2,627,771 (a decrease of approximately $13,000 from current interim rates under Interim Order No. 7115b).

b. The parties present their agreed-upon revenue requirement to the Commission without attribution of any kind, and without a specified cost of equity capital, capital structure, or weighted cost of capital.

c. The annual rate increase will be allocated between customer classes and rate schedules as follows:

Customer Classes	Current Revenues	Proposed Revenue Change	Percent Change
Residential- Rate 10	$12,898,287	$644,914	5.00%
Total Small General	7,825,066	461,679	5.90%
Total Large General Rate 30	10,459,270	899,497	8.60%
TOD Large General Rate 31	655,025	58,952	9.00%
Rate 35	9,169,024	485,958	5.30%
Lighting – Rate 41	471,532	42,438	9.00%
Municipal Pumping – Rate 48	381,466	34,332	9.00%
Outdoor Lighting – Rate 52	320,127		0.00%
Total Montana Electric	$42,179,797	$2,627,770	6.23%

The reasonableness of the proposed revenue increase is dependent upon the above allocation of that revenue requirement being adopted by the Commission in its final order in this docket.

d. MDU will withdraw its proposal to modify the provisions of its Fuel and Purchased Power Cost Tracking Adjustment (Rate 58), other than to change the unit rate and base fuel cost in accordance with the existing adjustment mechanism. The resale margin level to be used in the adjustment mechanism shall be $101,000, the actual 2010 level.

e. MDU will withdraw its proposals for a Renewable Resource Cost Recovery Rider (proposed Rate 56) and a Transmission Cost Recovery Rider (proposed Rate 57).

f. MDU will be allowed to amortize over a period of 15 years, beginning with calendar year 2011, the Montana allocated share ($3,788,267) of the deferred generation costs associated with the development and subsequent abandonment of three proposed generation resources: Big Stone II, the Gascoyne Project, and Milton R. Young III. However, the unamortized portion of these deferred generation costs will not be included in rate base.

g. The Commission should issue final rate orders in the pending Fuel and Purchased Power Cost Tracking Adjustments under both Rate 35 and 58.

Commission Discussion and Findings of Fact

203. At the hearing on June 29, 2011, the parties made available several witnesses to support the Stipulation and for questioning by Commissioners and staff. The witnesses who testified were David Goodin, Darcy Neigum, Tammy Aberle, and Rita Mulkern for MDU; Alan Rosenberg for Encore; and John Wilson for MCC.

204. The majority of the hearing testimony was provided by Goodin who reiterated the major reasons for the rate increase application by MDU and why, in his opinion, it was a fair request (Tr. 22-24). He also noted that the Stipulation is "just and reasonable, reflecting the true cost of service to provide to our customers today." (Tr. 26)

205. Goodin also responded to several questions from Commission staff concerning the deferred generation costs to be allocated to Montana customers. Goodin testified that the Big Stone II project was, in the company's opinion, a "worthwhile project" and that MDU should be allowed to recover all its costs for the failed projects because the costs were "reasonable and prudently incurred" by MDU. (Tr. 29 and 31)

206. After review of the evidence in this matter, the Commission finds the Stipulation provides a reasonable settlement of the issues in this case. The Stipulation recognizes MDU's current revenues are insufficient but it provides for a considerably smaller revenue increase than the utility requested. MDU's Application (as revised in December 2010) requested an annual revenue increase of $4,939,830 for its electric utility. The Stipulation provides instead an increase of $2,627,771, which is a reduction of $2,312,059 from MDU's requested increase and will result in rates that are slightly less than the interim rates currently in effect. The

Stipulation's proposed allocation of the revenue requirement among the various customer classes is also reasonable.

207. As part of the Stipulation, MDU withdrew its proposals for two new cost recovery riders (proposed Rate 56 and Rate 57), which were opposed by both MCC and Encore.

208. The Stipulation allows MDU to amortize over 15 years (but not rate-base) the Montana-allocated share of its deferred generation costs. MDU had requested a 10-year amortization and rate-base inclusion of the deferred generation costs. The MCC disagreed with the rate-base inclusion but agreed with the 10-year amortization of the deferred generation costs. It is important to note that extension of the amortization period from 10 to 15 years will lessen the yearly customer rate impact of the cost recovery. In addition, by allowing MDU to recover its generation resource planning costs but not allowing for a return on those costs through rate-basing them, the Stipulation provides for appropriate risk sharing between MDU and its customers for generation resource planning activities and does not discourage MDU from undertaking those activities.

209. The Commission agrees with the parties' proposal in the Stipulation to approve on a final basis the Fuel and Purchased Power Cost tracking adjustments that have already been implemented on an interim basis in Dockets D2008.5.53, D2009.6.87, D2009.12.153, D2010.6.66, and D2010.11.109.

210. MDU unintentionally omitted from Appendix 1 of the Stipulation two proposed tariff schedules, Rate 13 (Optional Residential Electric Thermal Energy Storage) and Rate 100 (General Provisions). At hearing, neither Encore nor MCC objected to including Rates 13 and 100 in Appendix 1. The Commission approves including Rates 13 and 100 as proposed by MDU in Appendix 1.

211. The revenue requirement in the Stipulation is approximately $13,000 less annually than the revenue requirement contained in Interim Order No. 7115b. Normally, the difference would be rebated to customers with interest. In this case, however, the Commission finds that the amount that would be rebated -- estimated to be about $5,000 for the partial year the interim rates have been in effect – is immaterial and no rebate is required. In lieu of a rebate, the Commission directs MDU to remit $5,000 to the state Department of Revenue for deposit in the low-income energy assistance fund administered by the state Department of Health and Human Services to be used for the benefit of customers in MDU's electric service territory.

212. Any findings of fact that are properly conclusions of law are hereby adopted as such.

Conclusions of Law

1. MDU furnishes electric service for consumers in the State of Montana, and as such is a "public utility" under regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

2. The Montana Public Service Commission properly exercises jurisdiction over MDU's rates and operations. Section 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

3. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. Section 69-3-303, MCA, and Title 2, Chapter 4, MCA.

4. The rate levels, revenue allocations, and rate design proposed in the all-party Stipulation is in the public interest, and will result in just and reasonable rates as required by Section 69-3-201, MCA.

5. Any conclusions of law that are properly findings of fact are hereby adopted as such.

Order

1. The Commission approves the Stipulation submitted by MDU, MCC and Encore in its entirety as a reasonable settlement of the contested issues in this case.

2. The Commission authorizes as final the rates set forth in the tariffs appended to the Stipulation as Appendix 1, including Rates 13 and 100, effective for service rendered on and after XX, 2011.

3. MDU must file tariffs in compliance with this Order within 30 days of the service date of this Order.

4. As noted in Finding of Fact No. 211, MDU is not ordered to rebate the difference between the rates approved in the Interim Order and this Final Order. Rather, MDU must remit $5,000 to the state Department of Revenue for deposit in the low-income energy assistance fund administered by the state Department of Health and Human Services to be used for the benefit of customers in MDU's electric service territory.

DONE IN OPEN SESSION at Helena, Montana, on this 26th day of July, 2011 by a vote of 3 to 2.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

TRAVIS KAVULLA, Chairman

GAIL GUTSCHE, Vice Chair

W. A. GALLAGHER, Commissioner
(Dissenting)

BRAD MOLNAR, Commissioner
(Dissenting)

JOHN VINCENT, Commissioner

ATTEST:

Aleisha Solem
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.

ATTACHMENT A

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

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REGULATORY DIVISION PUBLIC SERVICE COMMISSION

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 Electric Service	REGULATORY DIVISION DOCKET NO. D2010.8.82
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	DOCKET NO. D2008.5.53
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	DOCKET NO. D2009.6.87
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	DOCKET NO. D2010.6.66
IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	DOCKET NO. D2009.12.153
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	DOCKET NO. D2010.11.109

STIPULATION

COME NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota), the Montana Consumer Counsel (MCC), and, collectively, Encore Operating LP, ConocoPhillips, and Burlington Resources ("Encore and ConocoPhillips"), and agree and stipulate as follows:

1. On August 12, 2010, Montana-Dakota filed with the Commission an Application for authority to implement a general rate increase in the rates it is authorized to charge for electric service in Montana. The requested general rate increase was docketed as PSC Docket D2010.8.82.

2. The requested general rate increase, if granted in its entirety, would raise an additional $5,502,341 in annual revenues. Montana-Dakota also requested authority to modify its existing rate design. Included in the Application were requests for additional affirmative relief. Montana-Dakota proposed a Renewable Resource Cost Recovery Rider (proposed Rate 56), a Transmission Cost Recovery Rider (proposed Rate 57), and a modification of the Fuel and Purchased Power Tracking Adjustment (Rate 58). It also proposed the establishment of three new rate schedules (proposed Rates 13, 32, and 100), and the abolition of seven existing rate schedules (Rates 101, 102, 109, 114, 117, 122 and 130). All of the proposed changes in rate forms were set forth in proposed tariff sheets using legislative annotation and submitted as part of Appendix B to the Application.

3. The MCC intervened in the docket, opposing a rate increase of the magnitude requested by Montana-Dakota, the manner in which Montana-Dakota proposed to allocate its revenue deficiency between customer classes, the proposed new rate riders, and some of the proposed changes in rate design.

4. Encore and ConocoPhillips intervened in the docket, opposing a rate increase of the magnitude requested by Montana-Dakota, the manner in which Montana-Dakota proposed to allocate its revenue deficiency between customer classes, the proposed new rate riders, and some of the proposed changes in rate design.

5. The pre-filed testimony of the MCC expert witnesses was filed in this docket on December 17 and December 23, 2010. In that pre-filed testimony, the MCC concedes that Montana-Dakota has a revenue deficiency in the rates it is currently authorized to charge its Montana customers for electric service, but recommends an authorized rate increase of $583,696. The MCC also recommended rejection of the proposed new rate riders, and proposed an alternative allocation of the revenue deficiency between customer classes.

6. The pre-filed testimony of the Encore and ConocoPhillip's expert witnesses was filed in this docket on December 17, 2010. In that pre-filed testimony, Encore and ConocoPhillips concede that Montana-Dakota has a revenue deficiency in the rates it is currently authorized to charge its Montana customers for electric service, but recommends an authorized rate increase of $483,958. Encore also recommended rejection of the proposed new rate riders, and proposed an alternative allocation of the revenue deficiency between customer classes.

7. The revenue requirement presented by Montana-Dakota in this case included a weighted cost of capital of 8.778%, using the Company's actual capital structure and a cost of equity of 11.00%. The revenue requirements presented by the MCC, Encore and ConocoPhillips in this case included weighted costs of capital of between 72 and 78 Basis Points less than that developed by the Company. The MCC advocated that the cost of equity be set at 9.5%, while Encore and ConocoPhillips advocated that it be set at 9.6%.

8. On January 28, 2011, Montana-Dakota filed extensive rebuttal testimony in which it challenged the positions taken by the MCC, Encore and ConocoPhillips in this docket, including some of the mathematical calculations which were part of that advocacy.

9. The Commission, on February 8, 2011 issued in this docket its Interim Rate Order 7155b. The Interim Rate Order authorized, during the pendency of this proceeding, an interim rate increase in the annual amount of $2,640,725. The interim rate increase is being collected through a separate line item on the bill reflecting a 6.28% increase in the amount billed for each rate component under each rate schedule, with the exception of the Fuel and Purchased Power Cost Tracking Adjustment.

10. For settlement purposes, a fair and equitable resolution of the issues in PSC Docket D2010.8.82 between Montana-Dakota, the MCC, Encore and ConocoPhillips, one which would result in the establishment of just and reasonable rates, would be as follows, and as further described in paragraphs 11 through 12 below:

A. Montana-Dakota should be authorized, in a final rate order entered in PSC Docket D2010.8.82, to a overall annual increase in the rates it is authorized to charge for electric service in Montana in the amount of $2,627,771 (a decrease of approximately $13,000 from current interim rates under Interim Rate Order 7155b), provided, the rate increase is spread between rate classes in conformity with Paragraph 10.C below.

B. Because of the substantial divergence between the respective parties, as set forth in their pre-filed testimony, in both their rate making methodologies, and the end results of those rate making methodologies, the parties present their agreed upon revenue requirement to the Commission without attribution of any kind, except as set forth in Paragraph 11, and without a specified cost of equity capital, capital structure, or weighted cost of capital.

C. The annual rate increase specified in Paragraph 10.A above should be allocated between customer classes and rate schedules as set forth in this subparagraph:

Customer Classes	Current Revenues	Proposed Revenue Change	Percent Change
Residential - Rate 10	$12,898,287	$644,914	5.00%
Total Small General	7,825,066	461,679	5.90%
Total Large General Rate 30	10,459.270	899,497	8.60%
TOD Large General Rate 31	655,025	58,952	9.00%
Rate 35	9,169,024	485,958	5.30%
Lighting - Rate 41	471,532	42,438	9.00%
Municipal Pumping - Rate 48	381,466	34,332	9.00%
Outdoor Lighting - Rate 52	320,127	–	0.00%
Total Montana Electric	$42,179,797	$2,627.770	6.23%

The reasonableness of the proposed additional revenues set forth in Paragraph 10.A is dependent upon the interclass allocation of that revenue requirement, as set forth in this subparagraph, being adopted by the Commission in its final order in this docket.

D. In order to achieve the settlement of issues set forth in this Stipulation, Montana-Dakota will withdraw its proposal to modify the provisions of its Fuel and Purchased Power Cost Tracking Adjustment (Rate 58), other than to change the unit rate and base fuel cost in accordance with the existing adjustment mechanism. The resale margin level to be used in the adjustment mechanism shall be $101,000, the actual 2010 level.

E. In order to achieve the settlement of issues set forth in this Stipulation, Montana-Dakota will withdraw its proposal for a Renewable Resource Cost Recovery Rider (proposed Rate 56) and a Transmission Cost Recovery Rider (proposed Rate 57).

11. Montana-Dakota shall be allowed to amortize over a period of fifteen years, beginning with calendar year 2011, the Montana allocated share ($3,788,267) of the deferred generation costs associated with the development and subsequent abandonment of three proposed generation resources: Big Stone II, the Gascoyne Project, and Milton R. Young III.

However, the unamortized portion of these deferred generation costs will not be included in rate base.

12. Attached to this Stipulation as Appendix 1 are proposed tariffs implementing the various provisions of this Stipulation. If there is any conflict been the terms of this Stipulation and the proposed tariffs, the proposed tariffs control.

13. On November 30, 2009, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 35. The Application adjusted rates prospectively for the period January 1, 2010, through December 31, 2010, to capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Order 7055 to implement the rate change for the scheduled adjustment period.

14. On November 24, 2010, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 35. The Application adjusts rates prospectively for the period January 1, 2011, through December 31, 2011, to capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Order 7125 to implement the rate change for the scheduled adjustment period. Order 7125 effectively supercedes Order 7055 under the Rate 35 tracking adjustment mechanism.

15. On June 22, 2009, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 58. The Application adjusted rates prospectively for the period July 1, 2009 through June 30, 2010 to

capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Orders 7010 and 7011 to implement the rate change for the scheduled adjustment periods.

16. On June 22, 2010, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 58. The Application adjusted rates prospectively for the period July 1, 2010 through June 30, 2011 to capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Order 7094 to implement the rate change for the scheduled adjustment period. Order 7094 effectively supercedes Orders 7010 and 7011 under the Rate 58 tracking adjustment mechanism.

17. The parties agree that the Commission should issue final rate orders in the pending Fuel and Purchased Power Cost Tracking Adjustments under both Rate 35 and 58.

18. The Commission, after the completion of contested case proceedings in these dockets, should be moved in its discretion to issue a final order approving, adopting, and implementing the terms of this Stipulation and authorizing as final rates the tariffs set forth in Appendix 1, and finalizing the interim Fuel and Purchased Power Cost Tracking Adjustments pending in PSC Dockets D2008.8.53, D2009.6.87, D2010.6.66, D2009.12.153 and D2010.11.109.

19. The parties to this Stipulation present it to the Commission as a reasonable settlement of the issues raised in these dockets. No party's position in PSC Docket D2010.8.82 is accepted by the other parties by virtue of their entry into this Stipulation, nor does it indicate their acceptance, agreement, or concession to any rate making principle, cost

of service determination, or legal principle embodied, or arguably embodied, in this Stipulation.

20. The various provisions of this Stipulation are inseparable from the whole of the agreement between the parties to the Stipulation. The reasonableness of the proposed settlement set forth in this Stipulation is dependent upon its adoption, in its entirety, by the Commission. If the Commission decides not to adopt, in its entirety, the proposed settlement set forth in this Stipulation, then the entire Stipulation is null and void, no party to the Stipulation is bound by any provision of it, and it shall have no force or effect whatsoever.

21. The provisions of Paragraph 20 do not apply to the provisions of Paragraphs 13 through 19, as they relate to the Applications for Fuel and Purchased Power Cost Adjustment Cost Tracking Adjustments. Those provisions are separable from the other provisions of this Stipulation, and can be independently implemented by the Commission.

Dated this 26 day of May, 2011.

HUGHES, KELLNER, SULLIVAN & ALKE, PLLP

John Alke

John Alke
40 W. Lawrence, Suite A
P.O. Box 1166
Helena, MT 59624-1166

ATTORNEYS FOR MONTANA-DAKOTA UTILITIES

Dated this 9th day of May, 2011.

MONTANA CONSUMER COUNSEL

Mary Wright
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P.O. Box 201703
Helena, MT 5962-1703

Dated this 9th day of May, 2011.

HOLLAND & HART, LLP

Thorvald A. Nelson
8390 E. Crescent Parkway, Suite 400
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ATTORNEYS FOR ENCORE OPERATING LP;
CONOCOPHILLIPS; AND BURLINGTON RESOURCES

CERTIFICATE OF SERVICE

I hereby certify that a copy of **FINAL ORDER** issued in Docket Nos. D2010.8.82, D2008.5.53, D2009.6.87, D2009.12.153, D2010.6.66, and D2010.11.109 in the matter of Montana-Dakota Utilities Co. has today been served on all parties listed on the Commission's most recent service list, created 8/18/10, by mailing a copy thereof to each party by first class mail, postage prepaid.

Date: August 2, 2011

Donna Turkowski
For The Commission

Intervenors:

Burlington Resources

ConocoPhillips

Encore Operating LP

Montana Consumer Counsel

Utility - Docket Service List

D2010.8.82

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STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Electric Rate Increase
Application

Case No. PU-10-124

ORDER ON SETTLEMENT

June 8, 2011

Appearances

Commissioners Tony Clark, Brian P. Kalk, and Kevin Cramer.

Daniel S. Kuntz, Associate General Counsel, MDU Resources Group, Inc., 918 East Divide Avenue, Bismarck, North Dakota, Attorneys for the Applicant MDU Resources Group.

Annette Bendish, Legal Counsel, Public Service Commission, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota, Public Service Commission Advocacy Staff through July 31, 2010.

Richard J. Savelkoul, Attorney, Felhaber Larson Fenlon & Vogt, 444 Cedar Street, Suite 2100, St. Paul, Minnesota, Public Service Commission Advocacy Staff from October 12, 2010.

Illona A. Jeffcoat-Sacco, General Counsel and Mark E. Gruman, Legal Counsel, Public Service Commission, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota, Public Service Commission Advisors.

Scott Skokos, Missouri Valley Resource Council, Suite 8, 103 - 1/2 South Third Street, Bismarck, North Dakota, for Intervenor Missouri Valley Resource Council.

James D. Roaché, 707 First Street Southwest, Crosby, North Dakota, Intervenor, appearing *pro se*.

Al Wahl, Administrative Law Judge, Office of Administrative Hearings, 1701 North Ninth Street, Bismarck, North Dakota 58501-1882, as hearing officer.

Preliminary Statement

On April 19, 2010, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU) filed an application with the North Dakota Public Service Commission (Commission) seeking an annual revenue increase of $15,396,303 or 14 percent of total revenues.

On May 12, 2010, the Commission suspended the tariff revisions filed in MDU's Application.

On June 16, 2010 Advocacy Staff filed a Partial Settlement Agreement between MDU and Advocacy Staff relating to overall rate of return on MDU's rate base, including the return on equity component, for use in this proceeding. This Settlement Agreement was also received as MDU Exhibit 2.

Also on June 16, 2010, the Commission issued an Order on Interim Rates approving MDU's proposed interim rate increase.

Also on June 16, 2010, the Commission issued a Notice of Hearing and Notice of Public Input Sessions, scheduling public input sessions for July 12 and 13, 2010, and a formal hearing to begin November 8, 2010. The Notice specified the following issues to be considered:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

On July 6, 2010, MDU filed an amendment to its application eliminating from the application the Big Stone II generation development costs that were addressed in Case No. PU-09-733.

On July 12, 2010, and July 13, 2010, public input sessions were held via interactive television in Bismarck, Dickinson, and Williston, North Dakota.

On August 24, 2010, the Commission issued an Order granting the Petition to Intervene of James D. Roaché.

On October 4, 2010, the Administrative Law Judge issued an Order granting the Petition to Intervene of Harvey A. Christian as a customer of MDU.

On October 25, 2010, the Administrative Law Judge issued an Order granting the Petition to Intervene of Missouri Valley Resource Council (MVRC).

On November 1, 2010, Scott Skokos filed a Petition to Practice Law Before the North Dakota Public Service Commission in Case No. PU-10-124 for permission to represent MVRC. On November 2, 2010, Scott Skokos filed an amended Petition to Practice Law Before the North Dakota Public Service Commission, and on November 5, 2010, Mr. Skokos filed a Second Amended Petition to Practice Before the North Dakota Public Service Commission.

On November 5, 2010, Harvey A. Christian advised the Administrative Law Judge that he was abandoning his intervention.

On November 8, 2010, in response to the petitions of Mr. Skokos, the Administrative Law Judge issued an Order Granting Petition to Practice before Commission.

On November 8, 2010, during the hearing, a second Partial Settlement Agreement between MDU and Advocacy Staff was received as MDU Exhibit No. 3.

The Commission held a hearing on the application on November 8, 9, 10, and 12, 2010, in the Commission Hearing Room.

On March 14, 2011, MDU filed a third partially executed settlement agreement executed by MDU and Advisory Staff. Attached to the March 14, 2011 settlement agreement was an Additional Wind Investment Analysis prepared by MDU.

On March 15, 2011, MVRC filed a copy of the Settlement Agreement executed by MVRC.

On March 24, 2011, the Commission issued a Notice of Hearing and Notice of Intent to Consider Information Not Presented at a Hearing. The Notice indicated that the Commission could consider the Investment Analysis submitted by MDU as an attachment to the Settlement Agreement filed the same day. The Notice set a hearing on May 5, 2011, and specified the following issue to be considered:

> Whether the Settlement Agreement should be approved and adopted by the Commission for the determination of MDU's application to increase it's rates for electric utility service?

On May 5, 2011, the Commission held a formal hearing to consider the third Settlement Agreement.

Also on May 5, 2011, a fully executed copy of the third settlement agreement was received as MDU Exhibit 29.

Discussion

MDU originally proposed to increase its rates for electric utility service to provide $15,396,303 additional annual revenue, or a 14 percent increase over current rates. The proposed increase was based on a 2010 test year, a 9.09 percent return on MDU's rate base, including a 12 percent return on the equity component. MDU identified the primary drivers of the need for a rate increase as increased investment in facilities, including Cedar Hills and Diamond Willow wind generation projects, and a significant loss of wholesale margins.

The interim rate increase implemented by MDU provides $7,617,000 additional annual revenue until final rates are approved by the Commission. The interim rate increased revenue from each customer class by approximately 7 percent and collected the increased revenue using an increased per KWh use charge.

MDU's July 2010 application amended its rate increase application, eliminating from the application the Big Stone II generation development costs that were settled in another case, Case No. PU-09-731. The July 2010 application amendment reduces MDU's proposed rate increase from $15,396,303 to $13,300,000.

In the June 2010 settlement agreement, MDU and Advocacy Staff recommend a 10.75 percent return on the equity component of cost of capital. They also recommend an earnings sharing mechanism by which MDU would refund to customers revenues corresponding to 50 percent of earnings above a 10.75 percent return on equity. The settlement of these matters would reduce MDU's proposed rate increase from $13,300,000 to $11,519,000.

The November 2010 settlement agreement between MDU and Advocacy Staff proposed an 8.736 percent overall rate of return on MDU's rate base and also proposed resolutions for issues regarding:

- Margin sales and sales for resale,
- Aircraft,
- Customer deposits,
- Maintenance costs for the Big Stone and Coyote generating facilities,
- Transmission WAPA costs,
- Storm damages,
- Deferred generation costs, treatment of costs associated with refinancing certain debt at lower interest rate,

- Labor costs,
- Accounting system and jurisdictional allocation process,
- Minimum standard rate case filing requirements, and
- Corporate allocation and affiliate transactions.

The November 2010 settlement would further reduce MDU's proposed rate increase from $11,519,000 to $10,299,000. Intervenor MVRC and Intervenor Jim Roaché did not sign this settlement.

MDU testimony at the November 8, 2010 hearing reflected additional adjustments of investment and expenses related to the wind generation projects. These adjustments would reduce MDU's proposed rate increase from $10,299,000 to $8,825,000.

The March 2011 settlement agreement between MDU, MVRC, and Advocacy Staff, along with the June 15, 2010 and November 8, 2010 settlement agreements, proposes the resolution of all contested issues in the rate proceeding. Intervenor Jim Roaché did not sign this settlement. The settlement recommends that MDU be allowed to file rates for electric utility service to provide an annual test year revenue increase of $7,614,000 or 6.9 percent. The settlement agreement proposes the resolution of additional issues regarding:

- Cedar Hills and Diamond Willow wind projects,
- Employee compensation,
- Board of Director's fees and expenses,
- Renewable energy credits,
- Rate design,
- Time-of-day rates, and
- Customer bill form.

The rate increase would be an approximately equal percent increase to each customer rate class. The rate impact for an individual customer in the residential rate class would vary dependent upon the customer's electric usage.

Having considered this matter, the Commission finds the June 2010, November 2010, and the March 2011 Settlement Agreements are reasonable and should be approved. The Commission finds the return on rate base and the return on equity component proposed by the March 2011 Settlement Agreement is reasonable, however, the environment in which utilities operate continues to change and the Commission intends to investigate the factors affecting return levels for North Dakota utilities and investigate market and regulatory changes that affect those factors.

MDU testified that it has an unfunded pension liability that may need to be addressed in a future rate proceeding. Given that possibility, the Commission provides

the following thoughts so that the company can make decisions that align its interests with its customer service obligations.

1. A utility's rates must be just and reasonable. N.D.C.C. § 49-05-06. Just and reasonable rates must reflect only prudent costs. Prudent costs are those necessary and sufficient for efficient utility service. Those costs include the cost to attract and maintain a skilled workforce and costs associated with compliance with federal pension law.
2. Pension costs are affected by many factors. Some of these factors are within the utility's influence, including how it compensates its employees (e.g. salary levels; and the mix of salary, pension contributions and other benefits, including when and why it chose to move from defined benefit to defined contribution).
3. Other factors affecting pension costs are not within the utility's influence. These factors include the nation's economy, labor markets, stock market values and federal pension law.
4. The dividing line between factors within and outside the company's influence is not always clear. That lack of clarity complicates, but in no way eliminates, the Commission's obligation to ensure that the ratepayers bear only reasonable pension costs.
5. While just and reasonable rates may include only prudent costs, prudence does not guarantee cost recovery. There is no constitutional guarantee that a commission will include all prudent costs in rates. See Duquesne Light Co. v. Barasch, 488 U.S. 299, 307-16 (1989). It is lawful for a utility to bear some business uncertainties associated with prudent actions, because the utility's superior knowledge means it is in the best position to expose itself to these risks and manage them.
6. The Commission will apply these principles in reviewing any future utility request to reflect pension costs in rates. On making any such request, a utility should be prepared to:
   a. explain all causes of the unfunded liability;
   b. distinguish those factors over which it has influence, from those factors which are outside its influence;
   c. explain how it managed those factors over which it had influence;
   d. for those factors over which it did not have influence, explain how it anticipated those factors, what actions it took, both in advance and after the fact, to mitigate their effect; and
   e. explain to the commission its understanding of best practices in managing pension costs and how its actions compared to those best practices.

Having considered this matter, the Commission issues the following:

Order

1. The Settlement Agreements filed June 16, 2010, November 8, 2010 and March 15, 2011, a copy of each of which is attached to this Order, excluding the Additional Wind Investment Analysis that was attached to the March 15, 2011 Settlement Agreement, are made a part of this Order and are APPROVED.

2. MDU is authorized to implement an increase in its electric rates sufficient to produce a total annual revenue increase of not more than $7,614,000 in accordance with the rate design provided in the March 11, 2011 Settlement Agreement.

3. MDU shall file compliance tariffs consistent with this Order and the Settlement Agreements at least 30 days prior to the effective date of the rates.

PUBLIC SERVICE COMMISSION

Voting - Nay		
Kevin Cramer	**Tony Clark**	**Brian P. Kalk**
Commissioner	**Chairman**	**Commissioner**

MDU EXHIBIT 2

Public Service Commission
State of North Dakota

COMMISSIONERS

Kevin Cramer
Tony Clark
Brian P. Kalk

Executive Secretary
Darrell Nitschke

600 E. Boulevard Ave. Dept 408
Bismarck, North Dakota 58505-0480
Web: www.nd.gov/psc
E-mail: ndpsc@nd.gov
Phone 701-328-2400
Toll Free 1-877-245-6685
Fax 701-328-2410
TDD 800-366-6888 or 711

June 16, 2010

Darrell Nitschke
Executive Secretary
600 East Boulevard, Dept 408
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Electric Rate Increase
Application
Case No. PU-10-124

Dear Mr. Nitschke:

Enclosed is a Partial Settlement Agreement reached between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. and the North Dakota Public Service Commission Advocacy Staff in the above proceedings.

The Parties ask the Commission to approve the Settlement Agreement and are available to provide any additional information the Commission may require.

Please contact us with any questions.

Sincerely,

Annette Bendish
Counsel for Advocacy Staff

Enclosure

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a
Division of MDU Resources Group, Inc.
Electric Rate Increase Application

Case No. PU-10-124

PARTIAL SETTLEMENT

This Partial Settlement is entered into this 15th day of June, 2010, by and between the North Dakota Public Service Commission advocacy staff ("Staff") and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("Montana-Dakota"), (collectively, the "Parties"). This Partial Settlement sets forth the positions and recommendations of the Parties relating to the overall rate of return on the Company's rate base ("ROR"), including the return on equity ("ROE") component, for ratemaking purposes for the Company in the above-captioned proceeding. The Parties' recommendations are consistent with the public interest and will result in just and reasonable rates for the Company's retail electric operations in North Dakota.

TERMS OF SETTLEMENT

Reduced Return on Equity

The Parties agree that a 8.699 percent ROR is appropriate for determining the Company's revenue requirements in this proceeding. The Parties also agree to, and recommend the North Dakota Public Service Commission (the "Commission") approve in its final order, a ROE of 10.75 percent. The components of the recommended ROR are shown on Attachment 1 hereto.

The reasonableness of an 8.699 percent ROR and 10.75 percent ROE are supported by various considerations, including but not limited to the following:

- The 8.699 percent ROR is less than the 8.8 percent ROR approved in the December 31, 2008 final order for Xcel Energy in its most recent electric rate case, Case No. PU-07-776, and is based on the same 10.75 percent ROE as approved in that case.
- The 8.699 percent ROR is only slightly greater than the 8.62 percent ROR, and is the same 10.75 percent ROE, as approved by the Commission in Otter Tail Power Company's recent electric rate case, Case No. PU-08-862.

Customer Refunds for Earnings Above Threshold

The Parties agree to, and recommend that the Commission approve, an earnings sharing mechanism that will result in customer refunds if the Company's net income from electric utility service in North Dakota exceeds a 10.75 percent ROE.

If the Company earns in excess of 10.75 percent ROE as reflected in the annual report of jurisdictional regulated electric earnings for any fiscal year prior to either: (i) January 1, 2013; or (ii) the base period included in the Company's next electric general rate case (whichever occurs sooner); the Company will refund to customers revenues corresponding to 50 percent of earnings above 10.75 percent ROE.

Earnings sharing credits will be applied to customer accounts as soon as practical after July 1, following the annual report of electric earnings for the given fiscal year has been filed with the Commission (typically on April 15). A refund would be administered as a one-time bill credit.

OTHER TERMS AND CONDITIONS

Basis of Settlement

It is agreed this Partial Settlement is a negotiated Settlement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric general rate case and as required in tracking adjustment mechanisms that may be approved by the Commission, this Partial Settlement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

Effect of the Partial Settlement

It is understood and agreed that all offers of settlement and discussions related to this Partial Settlement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. This Partial Settlement shall not be deemed to prevent either the Staff or the Company from responding to positions taken by other intervenors in this proceeding; provided, however, that the Parties agree that such response shall not alter the positions and recommendations set forth in this Partial Settlement.

Effective Date

This Partial Settlement of Facts shall be effective as of the date hereof. It may be executed in counterparts.

Dated this 15th day of June, 2010.

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.

By: _____
Dennis L. Haider
Executive Vice President – Regulatory,
Gas Supply and Business Development

Dated this 15th day of June, 2010.

North Dakota Public Service Commission Staff

By: _____
Annette M. Bendish
Counsel to Advocacy Staff

ATTACHMENT 1

STIPULATED CAPITAL STRUCTURE AND OVERALL RATE OF RETURN

	Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$280,502,591	42.232%	6.845%	2.891%
Short-Term Debt	20,829,409	3.136%	2.535%	0.079%
Preferred Stock	15,500,000	2.333%	4.590%	0.107%
Common Equity	347,368,141	52.299%	10.75%	5.622%
Total Capitalization	$664,200,141	100.000%		8.699%

MDU RESOURCES
GROUP, INC.

1200 West Century Avenue
Mailing Address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000

Direct Dial No.
(701) 530-1016
(701) 530-1731 (fax)

March 11, 2011

Darrel Nitschke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Electric Rate Increase
Application
Case No. PU-10-124

Dear Mr. Nitschke:

Enclosed for filing are the original and seven copies of a Settlement Agreement between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., and the North Dakota Public Service Commission Advocacy Staff regarding the issues in the above-referenced proceeding. Montana-Dakota understands the Missouri River Resource Council is considering whether it will join the Settlement Agreement and will advise the Commission and parties upon reaching a decision. Mr. Roache' has previously indicated his opposition to the Settlement Agreement.

Attachment 1 to the Settlement Agreement consists of generation resource modeling information presented by Montana-Dakota Utilities Co. and considered by the parties during their settlement discussions. Attachment 1 is offered pursuant to N.D.C.C. § 28-32-25 solely for the purpose of the Commission's consideration of the Settlement Agreement. If the Commission determines to avail itself of the information presented in

167 PU-10-124 Filed 03/14/2011 Pages: 26
Settlement Agreement
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Daniel S. Kuntz

Attachment 1 in its consideration of the Settlement Agreement, Montana-Dakota will provide witnesses for examination and cross-examination regarding the information.

Sincerely,

Daniel S. Kuntz
Associate General Counsel

DSK/djv
Enclosure
cc: Illona Jeffcoat-Sacco
Mike Diller
Jim Roche'
Scott Skokos

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
a Division of MDU Resources Group, Inc.
Electric Rate Increase Application

Case No. PU-10-124

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 11th day of March, 2011, by and among the North Dakota Public Service Commission Advocacy ("Staff"), Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., ("Montana-Dakota" or "Company") and Missouri Valley Resource Council (collectively the "Settlement Parties"). The Settlement Parties agree this Settlement Agreement, if approved by the Public Service Commission ("Commission"), in conjunction with the prior settlement agreements between Staff and Montana-Dakota, resolve the issues in the above-captioned proceedings in a manner consistent with the public interest.

BACKGROUND

This proceeding involves Montana-Dakota's request to increase its retail rates in North Dakota to allow it to earn a reasonable return on equity.

Montana-Dakota's initial rate increase request was revised to $11,519,000 or approximately 10 percent, following a partial Settlement Agreement between the Company and Staff dated June 15, 2010. An interim rate increase of $7,617,000 or 7.04 percent was subsequently approved effective June 18, 2010.

Montana-Dakota identified the primary drivers for the need for its requested rate increase as increased investment in facilities, including the Cedar Hills and Diamond Willow wind generation projects, and the significant loss of wholesale sales margins.

By Settlement Agreement dated June 15, 2010, Montana-Dakota and Staff agreed on the values for Cost of Debt, Return on Equity, and overall Rate of Return for purposes of determining a test year revenue requirement in this proceeding. The June 15, 2010 settlement agreement was modified by a settlement agreement dated November 8, 2010, which also resolved issues regarding: (1) margin sales and sales for resale; (2) aircraft; (3) customer deposits; (4) maintenance costs for the Big Stone and Coyote generating facilities; (5) transmission WAPA costs; (6) storm damages; (7) deferred generation costs; (8) treatment of costs associated with refinancing certain debt at lower interest rate; and (9) labor costs. The November 8 agreement also included provisions regarding issues to be addressed by Montana-Dakota prior to its next general rate case including a potential study to be completed by a mutually agreed upon independent consultant regarding Montana-Dakota's accounting system and jurisdictional allocation process, minimum standard rate case filing requirements, and corporate allocations and affiliate transactions. The settlement of these matters reduced the Company's request by $1,220,000. Montana-Dakota's resulting rate request after adjustment for the June 16, 2010 and November 8, 2010 partial settlements was $10,299,000.

Montana-Dakota's rebuttal testimony presented at hearing reflected additional adjustments of investment and expenses related to the wind generation projects as a result of the enactment of the Small Business Jobs Act on September 27, 2010; a reduction in the depreciation rate for the 2010 wind projects from 5.17 percent to 5.0 percent; and the correction of an error in the original filing related to accumulated deferred income taxes. These adjustments lowered the revenue requirement

associated with the wind generation projects from $8,582,000 to $7,108,000. The total rate increase request, as effectively reduced by the settlements and adjustments for the wind projects, was $8,825,000 or 7.7 percent.

The Commission held a hearing on the Company's application on November 8-12, 2010, in the Commission Hearing Room. An Administrative Law Judge presided at the hearing. The Commission heard testimony regarding the proposed settlements as well as the remaining contested recommendations of the Staff to exclude from the Company's test year revenue requirement: (1) the investment and expenses associated with the Company's wind generation projects, (2) sixty percent of the Company's employee incentive compensation expenses, and (3) fifty percent of the Company's Board of Director's fees and expenses.

Following the filing of post-hearing briefs, the parties, as well as the Commission Advisory Staff, met for further settlement discussions. During those meetings the Company presented the results of generation resource modeling using the model and inputs that were used for development of the Company's 2009 Integrated Resource Plan ("IRP"). The modeling results presented by the Company provided a net present value comparison over 20 years of the difference between least cost generation resource scenarios, with and without the availability of the Big Stone II coal generation project, and scenarios in which the Diamond Willow and Cedar Hills wind generation projects were considered committed resources, also with and without the availability of the Big Stone II coal generation project. Upon request of the Staff, the Company provided additional modeling results after changing input values for market prices to test the sensitivity of the net present value differences to changes in market prices. The

results of the modeling are attached hereto as Attachment 1. In each instance, the delta between the 20 year net present value of the least cost generation resource scenarios without the Big Stone II project (which has been cancelled) and generation resource scenarios with the Diamond Willow and Cedar Hills wind projects as committed resources was less than two percent (less than 3.5 percent with the Big Stone II generation project).

In consideration of the record evidence of this proceeding, the post-hearing arguments and briefs of the parties, the modeling results provided by the Company, and further discussions by the parties, the parties agree to the following subject to approval of this Settlement Agreement by the Commission:

1. Revenue Requirement Increase. The parties agree to final rates in this proceeding providing for an annual test year revenue requirement increase for the Company of $7,614,000 which equals that of the annual interim revenue requirement increase previously approved in this proceeding.

2. Rate Design. The Company shall file revised rates implementing the test year revenue requirement increase based upon the rate design principles and changes proposed by the Company, including the changes to the Thermal Energy Storage Rate 13 presented at the technical hearing and introduced as Exhibit MDU-26. The Company shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement within 10 days after the issuance of a final order by the Commission.

3. Bill Form. Montana-Dakota will implement a new customer bill form with a target implementation date of December 31, 2012. This target date is subject to the

Company's conversion to a new customer information and billing system, currently underway, that meets all necessary metrics for implementation. Updates will be provided to the Commission and Staff as implementation progresses with any known delays reported to the Commission in a timely manner.

4. Time of Day Rate Study. Montana-Dakota will confer with Staff and, following review and approval by Staff, issue a request for proposals ("RFP") for a study on the cost effectiveness of implementing mandatory time of day rates applicable to its North Dakota electric system customers. Montana-Dakota will review the RFP results with the Commission Staff along with the Company's recommendations. Upon approval by the Staff of the scope and cost of a study, Montana-Dakota will commission the time of day rate study. Montana-Dakota will be allowed to recover the cost of the study, as well as the cost of the study provided in the settlement agreement of November 8, 2010, to the extent the Company's 2011 ROE, after considering the cost of the studies, is less than 10.75 percent. The costs shall be recovered as a separate charge included in the Fuel Clause Adjustment Rate 58 over a one-year period. The costs shall be recovered on a per kwh basis and shall be calculated by dividing the appropriate costs by the projected kwh sales volumes for the period the charge shall be in effect.

5. Renewable Energy Credits. Montana-Dakota will allocate the December 31, 2010 renewable energy credit balance and all future generated renewable energy credits (RECs) to each jurisdiction based on the kwh jurisdictional allocation factor. Renewable energy credits allocated to North Dakota will be sold at the

market price for the RECs with any proceeds flowed to customers through the Fuel Cost Adjustment Rate 58.

6. Basis of Settlement Agreement. It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

7. Effect of the Settlement Negotiations. It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

8. Applicability and Scope. This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The revised rates and tariff agreed to by this Settlement Agreement shall be effective on the dates specified in the Rate Design section of this Settlement Agreement.

9. Prior Settlements. The prior Settlement Agreements filed in this proceeding between the Company and Staff shall remain in effect and subject to approval by the Commission except to the extent modified by this Settlement Agreement.

10. Modification. If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either the Company or the Staff files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

CONCLUSION

The Settlement Parties have agreed to the foregoing terms to resolve the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Settlement Parties, are in the public interest and will result in reasonable electric issues. For these reasons, the Settlement Parties urge the Commission to approve the Settlement Agreement.

Dated this 11TH day of March 2011.

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.

By: David L. Goodin
DAVID L. GOODIN
Title: PRESIDENT & CEO

Dated this 11th day of March 2011.

North Dakota Public Service Commission Staff

By: Mike Diller
Mike Diller
Dir. of Econ. Reg.

Missouri River Resource Council

By: _____

Montana-Dakota Utilities Co.

Additional Wind Investment Analysis

North Dakota Rate Case No. PU-10-124

Overview

This additional analysis will look at the investments Montana-Dakota Utilities Co. (Montana-Dakota) made in Diamond Willow I, Diamond Willow II, and Cedar Hills to quantify the cost differential between resource portfolio additions based strictly on the least cost option and the Company's investment in renewable wind resources, using the 2009 North Dakota Integrated Resource Plan (2009 IRP).

Study Methodology

This analysis utilizes the same computer modeling tool that Montana-Dakota used in the 2009 IRP. This modeling tool was developed by Electric Power Research Institute (EPRI) and is named Electric Generation Expansion Analysis System (EGEAS). EGEAS is a resource planning software package which optimizes future supply-side resource selections based on needs, available resources, and economic criteria.

The 2009 IRP model provides an evaluation of the Company's need and the economic conditions and alternatives that were available to Montana-Dakota at the time of the decision to invest in the Diamond Willow II and Cedar Hills Projects. In the 2009 IRP, Diamond Willow I was already in-service and Diamond Willow II and Cedar Hills were considered as committed resources in Montana-Dakota's least cost plan.

To perform the analysis, the 2009 IRP model was adjusted to remove the Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects as in-service or committed resources. New site specific wind alternatives were created for the EGEAS model that reflected

the actual installed costs of Diamond Willow I, Diamond Willow II, and Cedar Hills. Additional generic wind generation projects in 30 MW blocks were available for selection in the model based on original modeling assumptions. The site specific wind alternatives included in the model are contained in the following table.

Site Specific Wind Alternatives	**Size (MW)**	**Capital**	**Capital per kW**	**In-service Available**
Diamond Willow I	19.5	$39.4 Mill	$2,020	Jan. 2009
Diamond Willow II	10.5	$25.4 Mill	$2,419	June 2010
Cedar Hills	19.5	$47.4 Mill	$2,431	June 2010

All other model inputs from the 2009 IRP for existing, committed, and alternative resources remain unchanged and are contained in Attachment A. Midwest ISO energy prices in the EGEAS model used for the 2009 IRP were $60 per MWh on-peak and $40 per MWh off-peak escalated at three percent (3%) per year in 2008 Dollars.

Scenarios

Two different scenarios were modeled as part of this analysis. In the first scenario the EGEAS model developed the least cost plan based on available resources assuming all site specific wind alternatives were available resources to the model and not committed or in-service projects. The second scenario committed any site specific wind alternative projects not selected in the least cost plan to determine the cost differential over the least cost plan associated with the site specific wind alternative projects.

The 2009 IRP included the Big Stone II project as a committed least cost resource based on prior expansion analyses. Each of the two scenarios developed for this analysis were run with

and without Big Stone II in the model to recognize that the Big Stone II resource is no longer available to Montana-Dakota's customers.

The EGEAS model optimizes investment and production costs over the study period and determines a net present value (NPV) for the model solution. For the 2009 IRP, a fifty (50) year study period was used to develop the least cost scenario. For this analysis the timeframe was reduced to a twenty (20) year period to reflect the life expectancy of the wind generation investments.

Results

- First Scenario
  - With Big Stone II - no wind projects selected
  - Without Big Stone II - Diamond Willow I selected

Case	Net Present Value*
With Big Stone II	$1,439.82 Mill
Without Big Stone II	$1,370.48 Mill

- Second Scenario
  - With Big Stone II – Diamond Willow I, Diamond Willow II, and Cedar Hills were committed resources to the least cost plan
  - Without Big Stone II – Diamond Willow II and Cedar Hills were committed to the least cost plan

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,481.72 Mill	2.9 %
Without Big Stone II	$1,386.85 Mill	1.2 %

*Net Present Value calculated over 20 years in 2008 Dollars.

A summary table of selected resources for both the First Scenario and Second Scenario is contained in Attachment B.

Analysis

The NPV numbers referenced in the results correspond to the entire Montana-Dakota integrated system and are not state specific. The NPV of production costs includes future operations and maintenance charges for all resources, fuel costs, market purchases, and recovery of future capital investments associated with the supply side resources.

As discussed in more detail in the Company's current North Dakota rate case; the Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects are currently in-service and are used and useful in providing electric service to Montana-Dakota's North Dakota customers. The purpose of this analysis is to show if there is a cost adder for renewable wind generation above Montana-Dakota's least cost resource plan.

With the Big Stone II project, none of the three site specific wind alternatives were picked in the least cost plan. It should be noted that under the normal fifty (50) year modeling period the NPV of the With Big Stone II case is less than the NPV of the Without Big Stone II case. The reason for this is that the investment benefit of a baseload coal-fired plant is received over the entire forty (40) plus year life of the asset which is not adequately reflected in a twenty (20) year study timeframe.

Montana-Dakota was ultimately unsuccessful in its attempts to develop the Big Stone II project and the Without Big Stone II scenario is the appropriate case to focus on for the additional cost of wind generation.

Under the Without Big Stone II modeling runs, the resource expansion model selects the Diamond Willow I project in the least cost plan. The incremental NPV cost to all state jurisdictions with the inclusion of Cedar Hills and Diamond Willow II in the Without Big Stone II runs is $16.37 million over the twenty (20) year life of the projects. This represents an increase of 1.2 percent over the least cost plan.

North Dakota's state jurisdictional share of the Cedar Hills and Diamond Willow II investments is approximately sixty-five percent (65%) which allocates $10.64 million of the NPV increase to North Dakota customers. The Cedar Hills project received a Certificate of Public Convenience and Necessity (CPCN) from the North Dakota Public Service Commission based upon estimated completion costs presented in the Company's application. The Cedar Hills project came in on budget and on schedule. The Cedar Hills wind project is rated at 19.5 MW and the Diamond Willow II project is rated at 10.5 MW for a total of 30 MW. Cedar Hills represents sixty-five percent (65%) of the total wind investment in the Cedar Hills and the Diamond Willow II projects. Therefore only thirty-five percent (35%) of North Dakota's share of the incremental NPV for wind generation should be considered a cost adder above the Without Big Stone II least cost plan which represents a NPV of $3.72 million. Using an eight percent (8%) discount rate and a twenty (20) year term, the annual levelized cost impact to North Dakota customers for Diamond Willow II is $379,000 per year.

This analysis does not include any benefit to North Dakota customers for the North Dakota earned investment tax credit for Cedar Hills or the additional bonus tax depreciation that was available in 2010 for Diamond Willow II or Cedar Hills.

Conclusion

The Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects are used and useful in providing electric service to Montana-Dakota's customers and provide numerous benefits including: reduced dependency on market purchases, reduced exposure to market price fluctuations, zero marginal cost generation resources, and a fuel diversified generation fleet. The cost differential between resource portfolio additions based strictly on the least cost option and the Company's investment in renewable wind resources is 1.2 percent.

Additional Modeling Runs

Additional modeling sensitivity runs requested by the North Dakota Public Service Commission Advocacy Staff are included in Attachment C. Additional sensitive runs looked at lower forecasted Midwest ISO energy market prices of $40 per MWh on-peak and $20 per MWh off-peak; and $50 per MWh on-peak and $30 per MWh off-peak. Also included in Attachment C are summaries of modeling runs to show the affects of using a 25 year depreciation life for the wind turbine investments versus the Company proposed 20 year depreciation life.

Attachment 1

Attachment A

Following tables are referenced from the 2009 IRP

Table A-1

Montana-Dakota's Existing Coal-Fired Units

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Coyote[2]	106.75	20.20	2.25	1.14
Big Stone Unit I[3]	107.50	19.89	1.50	1.57
Heskett 1	27.96	50.57	5.98	1.59
Heskett 2	74.17	44.71	7.07	1.59
Lewis & Clark	52.30	43.55	2.47	1.13

1. Based on July URGE rating (1/1/08-10/31/09)
2. Montana-Dakota's 22.7% ownership share
3. Montana-Dakota's 25% ownership share

Table A-2

Montana-Dakota's Existing Natural Gas Combustion Turbines

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Glendive 1	36.0	9.48	2.35	6.90
Glendive 2	41.6	5.58	2.35	6.90
Miles City	24.5	9.06	2.35	6.90
Williston	9.6	3.08	2.35	6.90

1 – Based on July URGE rating (11/1/08-10/31/09)

Table A-3

Montana-Dakota's Existing Contracts, Variable Generation, and Diesel Unit

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow[1]	4.37	10.16	-27.23	-
Glendive Diesel	2.01	4.00	2.35	16.57
Glen Ullin Station 6	4.50	31.33	6.5	-
NSP contract[2]	95.00	17.70	84.30	-
NSP contract[3]	10.00	17.70	184.30	-
WAPA contract[4]	2.80	-	16.84	-

1. Summer Accredited Capacity is based on 22.43% capacity factor. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.
2. Increase to 100 MW in 2010 with option years in 2011-12.
3. Expires in 2010
4. Expires in 2020

Table A-4

Montana-Dakota's Committed Resources

Unit	In-Service Date	Summer Accredited Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU
Big Stone Unit II	2015	131.00	2938.59	29.84	1.80	1.66
WE Energies Contract	2012-2014	110-120	-	34.80	111.50	-
NSP Contract Extension	2011	105.00	-	21.00	77.50	-
Diamond Willow Addition[1]	2010	2.24	2400.00	10.16	-27.23	-
Cedar Hills Wind[1]	2010	4.37	2400.00	10.16	-28.77	-

1 - Summer Accredited Capacity is based on 22.43% capacity factor. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.

Table A-5

Resources Alternatives Available to Montana-Dakota

Unit	Size (MW)	Available Date	Capital Cost ($/kW)[2]	Fixed O&M ($/kW-year)[3]	Variable O&M ($/MWh)[3]	Fuel Cost ($/MBTU)
Combustion Turbine	43	2010	850	$11.63	$2.00	$6.90
Combustion Turbine	75	2010	750	$8.67	$2.00	$6.90
Combined Cycle	140	2010	1150	$12.50	$6.00	$6.90
Coal	blocks of 30	2013	3900	$48.00	$2.50	$1.50
Wind	blocks of 30	2009	2400	$23.33	$2.00	-
Wind before 2014[1]	blocks of 30	2013	2400	$23.33	-$27.23	-
Purchased Capacity	blocks of 10	2012	-	$34.80	$111.50	-

1 - Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.
2 - In 2008 dollars escalated at 7%
3- In 2008 dollars escalated at 4%

Attachment B

Summary Results for Additional Wind Analysis

Year	Scenario 1		Scenario 2	
	With Big Stone II	**Without Big Stone II**	**With Big Stone II**	**Without Big Stone II**
2009	Glen Ullin	Glen Ullin & DW I	Glen Ullin & DW I	Glen Ullin & DW I
2010			DW II & CH	DW II & CH
2011	20 MW Purchase	20 MW Purchase	10 MW Purchase	10 MW Purchase
2012	140 MW Purchase	130 MW Purchase	120 MW Purchase	120 MW Purchase
2013	150 MW Purchase	140 MW Purchase	130 MW Purchase	130 MW Purchase
2014	150 MW Purchase	150 MW Purchase	140 MW Purchase	140 MW Purchase
2015	BSP II & CT75	2-CT75 & CT43	CT75	2-CT75 & CT43
2016				
2017				
2018				
2019	CT43	CT43		CT43
2020				
2021			CT43	
2022				
2023		CT43		
2024	CT43			CT43
2025			CT43	
2026				
2027		CT43		
2028	CT43			CT43
NPV*	1,439.82	1,370.48	1,481.72	1,386.85

*Net Present Value (NPV) in millions of Dollars over 20 year study period
CT43 – 43 MW Combustion Turbine
CT75 – 75 MW Combustion Turbine
DWI – Diamond Willow I
DWII – Diamond Willow II
CH – Cedar Hills
Purchase – Purchased Capacity

Attachment C

$20 & $40/MWh Market Prices

Results

On-Peak: $40/MWh in 2008 dollars escalated at 3%
Off-peak: $20/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - No wind selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,410.12 Mill
Without Big Stone II	$1,314.64 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,458.68 Mill	3.4 %
Without Big Stone II	$1,337.89 Mill	1.8 %

*Net Present Value based over 20 years

$30 & $50/MWh Market Prices

On-Peak: $50/MWh in 2008 dollars escalated at 3%
Off-peak: $30/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,427.35 Mill
Without Big Stone II	$1,345.79 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,472.34 Mill	3.2 %
Without Big Stone II	$1,364.87 Mill	1.4 %

*Net Present Value based over 20 years

25 Year Book Life

$40 & $60/MWh Market Prices

Results

On-Peak: $60/MWh in 2008 dollars escalated at 3%
Off-peak: $40/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,648.70 Mill
Without Big Stone II	$1,593.51 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,675.67 Mill	1.6 %
Without Big Stone II	$1,599.57 Mill	0.4 %

*Net Present Value based over 25 years

25 Year Book Life

$20 & $40/MWh Market Prices

Results

On-Peak: $40/MWh in 2008 dollars escalated at 3%
Off-peak: $20/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,614.40 Mill
Without Big Stone II	$1,529.05 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,648.99 Mill	2.1 %
Without Big Stone II	$1,541.03 Mill	0.8 %

*Net Present Value based over 25 years

25 Year Book Life

$30 & $50/MWh Market Prices

On-Peak: $50/MWh in 2008 dollars escalated at 3%
Off-peak: $30/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,634.17 Mill
Without Big Stone II	$1,563.93 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,664.70 Mill	1.9 %
Without Big Stone II	$1,572.99 Mill	0.6 %

*Net Present Value based over 25 years

Summary Results for 25 year book life

Year	Scenario 1		Scenario 2	
	Big Stone II	No Big Stone II	Big Stone II	No Big Stone II
2009	Glen Ullin	Glen Ullin & DW I	Glen Ullin & DW I	Glen Ullin & DW I
2010			DW II & CH	DW II & CH
2011	20 MW Purchase	20 MW Purchase	10 MW Purchase	10 MW Purchase
2012	140 MW Purchase	130 MW Purchase	120 MW Purchase	120 MW Purchase
2013	150 MW Purchase	140 MW Purchase	130 MW Purchase	130 MW Purchase
2014	150 MW Purchase	150 MW Purchase	140 MW Purchase	140 MW Purchase
2015	BSP II & CT43	2-CT75 & CT43	BSP II & CT75	2-CT43 & CT75
2016	CT43			
2017				
2018				
2019		CT43		
2020				CT43
2021	CT43		CT43	
2022				
2023		CT75		
2024				
2025	CT43		CT43	CT43
2026				
2027				
2028				

CT43 – 43 MW Combustion Turbine
CT75 – 75 MW Combustion Turbine
DW I – Diamond Willow
DW II – Diamond Willow
CH – Cedar Hills
Purchase – Purchased Capacity

MDU EXHIBIT 3

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.,
Electric Rate Increase Application

Case No. PU-10-124

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 8th day of November, 2010, by and between the North Dakota Public Service Commission Advocacy Staff ("Staff"), Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., ("Montana-Dakota" or "Montana-Dakota"). Montana-Dakota and Staff were not able to complete this Settlement Agreement timely, such that other parties were able to consider it. This Settlement Agreement resolves certain outstanding issues in the above-captioned proceedings in a manner consistent with the public interest.

BACKGROUND

This proceeding involves Montana-Dakota's request to increase its retail rates to allow it to earn a reasonable return on equity.

Montana-Dakota sought to increase retail rates by $11,519,000, reflecting the Settlement Agreement dated June 16, 2010 or 10 percent. An interim rate increase of $7.6 million or 7 percent was approved effective June 18, 2010.

Montana-Dakota's electric operations in North Dakota were revenue deficient and earnings were below a reasonable return on equity ("ROE"). Montana-Dakota's last North Dakota general electric rate case was in 2003 with final rates effective January 2004.

In this current rate case, Montana-Dakota identified primary drivers for the need to request a rate increase as increased investment in facilities, including the expansion of wind generation in the Cedar Hills and Diamond Willow projects and the associated expenses and the significant loss of wholesale sales margin.

Montana-Dakota and Advocacy staff previously settled Cost of Debt, Return on Equity and overall Rate of Return, which are modified in this Settlement Agreement. Issues that remain disputed include handling of investments in wind generation and handling of incentive compensation and Board of Directors expenses.

Terms

The Parties agree to the provisions as defined below.

I. Rate Base and Revenue Requirements in the Rate Case.

The Parties agree with respect to the items discussed below. The agreement is made relative to the revised request amount of $11,519,000 and is net of Rate Base, ROR and Expense adjustments proposed by Staff. With respect to the settled items below, Staff proposed adjustment of $2,354,000, the Parties agree that Staff's proposed adjustment should be reduced to $1,220,000. This $1,220,000 will reduce the total request amount of $11,519,000. The parties do not agree how much of a reduction is necessary for Wind or Incentive Compensation and Board of Directors costs.

A) Rate of Return.

The Parties agree to a return on equity of 10.75 percent, with the capital structure and cost set forth in the table below:

Long Term Debt	41.084%	6.845%	2.812%
Short Term Debt	3.199%	2.535%	0.081%
Preferred Stock	2.380%	4.590%	0.109%
Common Equity	53.337%	10.750%	5.734%
Total	100.000%		8.736%

Montana-Dakota agrees to share any earnings above 10.75 percent with customers (see Other Terms and Conditions for a full discussion of this sharing mechanism).

The Parties also agree that an overall rate of return of 8.736 percent will be used for purposes of determining interim rates in Montana-Dakota's next electric rate case.

B) Resolved Issues.

Advocacy Staff's responsive testimony raised several issues of concern. As set forth below, the parties resolve all of the issues, with the exception of bonus and incentive compensation, Board of Directors expense and recovery of wind generation investment and related expenses. As stated above, the total agreed upon adjustment on agreed upon issues, net of Rate Base, ROR and expense items is $1,220,000. The parties have not agreed to an exact allocation of which issues are assigned specific adjustments, rather the parties agree to the reasonableness of the overall adjustment without allocation to specific items.

The non-monetary adjustments which have been agreed upon are covered herein, below.

Advocacy Staff's adjustment proposals included concerns and the Advocacy Staff requested adjustments on the following issues:

(1) Margin Sales and Sales for Resale. Advocacy Staff believed these were separate issues and requested a fixed amount be placed into the cost of service, based on 2009 actual wholesale sales margin. Montana-Dakota proposed to remove all wholesale sales margins from base rates and pass

through 85% of the margins to customers via the Fuel and Purchased Power Adjustment Clause (FCA).

(2) Aircraft. Montana-Dakota sought recovery for its ownership in certain aircraft used for travel to service territory locations that are not provided with adequate commercial travel. Advocacy Staff challenged inclusion of the aircraft in rate base, as well as applicable expense items in Montana-Dakota's income statement. Montana-Dakota believes its investment is prudent and a legitimate cost of doing business.

(3) Customer Deposits. Advocacy Staff had concerns regarding MDU not using Customer Deposits as a reduction to rate base. Staff requested the jurisdictional amount, instead MDU provided both electric and gas combined balance. Montana-Dakota argues that customer deposits were not included as a reduction to rate base because interest is paid on customer deposits. Staff and Montana-Dakota agreed to include the Customer Deposits applicable to Electric service in the rate base and related interest expense in the cost of service.

(4) Maintenance Costs for Big Stone and Coyote Generating Facilities. Advocacy Staff had concerns about the unusually high maintenance costs included in the test year for the Big Stone and Coyote generating facilities. Montana-Dakota believes that if maintenance expenses are adjusted, the corresponding operation expenses should be treated the same way.

(5) Transmission – WAPA Costs. Advocacy Staff believed there was too high of a charge included for transmission and WAPA charges. Montana-Dakota did not object to the adjustment.

(6) Storm Damages. Advocacy Staff proposed Montana-Dakota be entitled to recovery for storm damages. Advocacy Staff requested that Major Storm Damages be tracked and accounted by the Company, so that from rate case to rate case it can be tracked and properly recovered. Advocacy Staff believes Montana-Dakota should be entitled to a normalized amount to cover costs of major storm damages. Montana-Dakota did not object to the adjustment.

(7) Deferred Generation Costs. Advocacy Staff believed Montana-Dakota should not be entitled to recover deferred generation costs that fall outside of the rate case. Montana-Dakota believes the deferred generation costs were prudently incurred and should be recovered. The Company applied for a deferred accounting order for these generation development costs.

(8) Treatment of Costs Associated with Refinancing Certain Debt at Lower Interest Rates. Advocacy Staff was supportive of recovery, but proposed modification as to how the Company recovered costs associated with refinancing debt. Montana-Dakota believes its treatment of the unamortized loss on debt and associated debt costs is in compliance with FERC accounting.

(9) Labor Costs. Advocacy Staff had concerns regarding the level of labor costs and compensation being included in the rate case, along with the

methodology being used to calculate those costs for the test year. Montana-Dakota does not believe that Staff reflected current (2010) wage and salary levels in its adjustment.

C) Wholesale Sales margins

For purposes of determining the overall revenue requirement, the Parties agree to credit to customers through the FCA 100 percent of North Dakota's portion of asset-based margins received by Montana-Dakota. Passing these credits directly through the FCA as they are realized ensures that neither customers nor Montana-Dakota will be disadvantaged by a non-representative margin forecast in the test year. Montana-Dakota will, starting with the month final rates go in place, include in its fuel clause adjustment calculation, the actual amount of wholesale sales margins for the applicable month. Any balance of unrecovered Margin Sharing Adjustment (MSA) amount remaining at time final rates become effective will be recovered over a twelve month period based on forecasted kWh sales volumes and included in the FCA until fully recovered.

II. Issues to be Addressed before Montana-Dakota's Next Rate Case.

Montana-Dakota will meet with the Staff to discuss a potential study to be completed by the filing of the Company's next general rate case and to be conducted by a mutually agreeable independent consultant. The Company agrees to fund up to $125,000, or such other mutually agreeable amount, for such study. The scope of the study shall be agreed to by the parties but may include all or any of the following three major issues raised by the Staff in this proceeding:

1. Review Montana Dakota's Accounting System and the jurisdictional allocation process. One of the goals is, to determine if a better process can be developed to create an easier audit trail and a more transparent reporting process.
2. Develop an appropriate Minimum Standard Filing Requirements to facilitate a better review of Rate Case components in future cases. Staff will take the lead in identifying the standard information to be filed when requesting for a rate increase.
3. Review the corporate allocation process and the affiliate transactions used to allocate costs associated with MDU Resources and other affiliates to Montana-Dakota's gas and electric operations.

III. Allocations and Rate Design for the Rate Case.

The rate design shall be as Montana-Dakota proposed in its request, modified to reflect adjustments to the revenue requirement and class allocations described in this Agreement.

Montana-Dakota shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement at least thirty (30) days prior to the effective date of final rates.

IV. Other Terms and Conditions

A) Customer Refunds for Earnings Above Authorized ROE.

Per the settlement in Attachment A, the Parties agree to an earnings-sharing mechanism that will result in customer refunds if the Company's net income exceeds a 10.75 percent ROE for its North Dakota electric operations.

If the Company earns in excess of 10.75 percent ROE as reflected in the annual report of jurisdictional regulated electric earnings for any fiscal year prior to either: (i) January 1, 2013; or (ii) the base period included in the Company's next electric general rate case (whichever occurs sooner); the Company will refund to customers revenues corresponding to 50 percent of earnings above 10.75 percent ROE.

Earnings sharing credits will be applied to customer accounts as soon as practical after July 1, following the annual report of electric earnings for the given fiscal year has been filed with the Commission (typically on April 15). A refund would be administered as a one-time bill credit.

B) Deferred Generation Costs.

The Company shall be entitled to recover, outside of rate base, a $172,000 expense, for ten years. The parties agree that this amount will be included in expenses of future rate cases for ten years from the filing of this rate case. This amount is included in and not in addition to the settled amount discussed above.

C) Basis of Settlement Agreement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric general rate case, as required in tracking adjustment mechanisms that may be approved by the Commission, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

D) Effect of the Settlement Negotiations.

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

E) Applicability and Scope.

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

F) Effective Date.

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve some of the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Parties, are in the public interest and will result in reasonable electric rates.

For these reasons, the Parties urge the Commission to approve the Settlement Agreement.

Dated this 8th day of November, 2010.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc

By: _____
Name and title
DAVID L. GOODIN
PRESIDENT + CEO

Dated this 8th day of November, 2010.

North Dakota Public Service Commission Staff

By: _____
Name and title
Attorney for
Commission Staff

Received
SD PUC
JUN 04 1986

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

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 ELECTRIC SERVICE.	)	ORDER APPROVING TARIFFS (F-3576)

On May 9, 1986, the Commission approved a negotiated Settlement Agreement between MDU and the Commission Staff in the above-entitled proceeding. In its Order Approving Settlement Agreement, the Commission required MDU to file rate schedules and related tariff sheets consistent with the revenue level agreed to in the Settlement Agreement. The Commission further ordered that the increase would be effective for electric service rendered on and after June 1, 1986.

On May 19, 1986, MDU filed the following tariff sheets applicable to electric service in South Dakota:

Section No. 1, 8th Revised, Sheet No. 1
Section No. 1, 5th Revised, Sheet No. 1.1
Section No. 2, 3rd Revised, Sheet No. 1
Section No. 2, 2nd Revised, Sheet Nos. 1.1 and 1.2
Section No. 3, 5th Revised, Sheet Nos. 1, 5.1, 6, 10, 12, 14, 19, 21, 23 and 26
Section No. 3, 4th Revised, Sheet Nos. 1.1, 3.1, 10.1, 12.1, 14.1, 16, 19.1, 21.1, 24.1, 24.2, 25.1 and 25.2
Section No. 3, 6th Revised, Sheet Nos. 3 and 5
Section No. 3, 1st Revised, Sheet Nos. 5.3, 5.4, 7, 7.1, 7.2, 14.2, 15, 15.1, 15.2 and 26.1
Section No. 3, 2nd Revised, Sheet Nos. 6.1, 6.2, 28.1, 29.1, 29.2, 30.1, 30.2, 31.1 and 31.2
Section No. 3, 7th Revised, Sheet Nos. 24 and 25
Section No. 3, 3rd Revised, Sheet Nos. 27, 28, 29, 30, 31, 32 and 32.1
Section No. 4, 3rd Revised, Sheet No. 1
Section No. 5, 4th Revised, Sheet Nos. 1, 5, 9, 9.1, 9.2 and 11
Section No. 5, 3rd Revised, Sheet Nos. 2, 6, 7, 10, 13, 15, 15.1, 15.2 and 16
Section No. 5, 1st Revised, Sheet No. 7.1
Section No. 5, 5th Revised, Sheet No. 8
Section No. 5, 2nd Revised, Sheet Nos. 8.1 and 8.2
Section No. 5, 6th Revised, Sheet No. 14

The Commission has jurisdiction to approve the tariff sheets pursuant to SDCL 49-34A.

The Commission has carefully reviewed said tariff sheets and finds that they properly implement the revenue level increase approved by the Commission in its Order Approving Settlement Agreement. The Commission further finds that said revised tariff sheets establish just and reasonable rates for MDU's retail electric service in South Dakota. The Commission finds therefore that said revised tariff sheets should be approved on the terms and conditions set forth therein. The Commission reserves the right to modify said tariff sheets by further order in this docket. It is therefore

ORDERED, that said tariff sheets be and the same hereby are approved upon the terms and conditions set forth therein and shall be effective for service rendered on and after the 1st day of June, 1986.

Dated at Pierre, South Dakota, this 29th day of May, 1986.

BY ORDER OF THE COMMISSION:

JEFF SOLEM, Chairman

KENNETH STOFFERAHN, Commissioner

DENNIS EISNACH, Commissioner

(OFFICIAL SEAL)

Rec'd SD PUC
MAY 12 1986

BEFORE THE PUBLIC UTILITIES COMMISSON

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO ESTABLISH INCREASED RATES FOR ELECTRIC SERVICE.	)))))	ORDER APPROVING SETTLEMENT AGREEMENT (F-3576)

On April 24 and 25, 1986, representatives of Montana-Dakota Utilities Co. (MDU) and Commission Staff met in Pierre, South Dakota to discuss settlement of the above-entitled proceeding. Subsequent to the meeting, MDU and Staff filed with this Comission a Settlement Agreement. Both parties agreed, should MDU commence the purchase of 41 megawatts of power from Basin Electric Power Cooperative Antelope Valley Station II on June 1, 1986, that the filed Settlement Agreement resolves all issues in this proceeding. On May 8, 1986, MDU filed a letter with this Commission stating that MDU would in fact commence the purchase of the power on June 1, 1986. This letter is attached and is hereby incorporated in this Order.

The Commission has carefully reviewed the Settlement Agreement and the letter filed by MDU. The Commission finds that the Settlement Agreement reached by the parties in this matter properly establishes just and reasonable rates and therefore should be approved. The Commission further finds that MDU should file rate schedules and related tariff sheets consistent with the revenue levels established in the Settlement Agreement. It is therefore

ORDERED, that the settlement reached between MDU and Commission Staff in this matter be and the same hereby is approved upon the terms and conditions set forth in the Settlement Agreement and the attached letter; and it is

FURTHER ORDERED, that MDU file with this Commission rate schedules and related tariff sheets consistent with the revenue level agreed to in the Settlement Agreement, to be effective for electric service rendered on and after June 1, 1986.

Dated at Pierre, South Dakota, this 9th day of May, 1986.

BY ORDER OF THE COMMISSION:

JEFF SOLEM, Chairman

KENNETH STOFFERAHN, Commissioner

DENNIS EISNACH, Commissioner

(OFFICIAL SEAL)

Received
SD PUC
MAY 07 1986

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

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 ELECTRIC SERVICE.	)	DOCKET NO. F-3576

SETTLEMENT AGREEMENT BETWEEN
MONTANA-DAKOTA UTILITIES CO.
AND COMMISSION STAFF

This Settlement Agreement is made and entered into between Montana-Dakota Utilities Co. (Company) and the Staff of the Public Utilities Commission (Staff).

BACKGROUND

On December 31, 1985, Company filed an application for authority to establish increased rates for electric service with the South Dakota Public Utilities Commission (Commission). The Company's application, based upon a test year ended June 30, 1985, sought approval of rates which would yield Company additional annual revenues of approximately $1,579,044. Staff's direct presentation in this case was submitted to the Commission on April 9, 1986. Staff initially recommended that Company be allowed an increase of $37,624 in its electric rates, exclusive of any adjustment relating to the purchase of additional capacity from Antelope Valley Station II (AVSII). When including the AVSII adjustment, Staff initially recommended that Company be

allowed an increase of $537,309 in electric rates. Company submitted rebuttal testimony on April 21, 1986. No interventions were filed in this application. On April 24 and 25, 1986, representatives of Company and Staff attended an informal settlement conference. As a result of the conference, Company and Staff reached a settlement regarding the level of Company's increased revenues and certain other matters as set forth below.

ELEMENTS OF THE SETTLEMENT AGREEMENT

Article I. Settlement Rates

Company and Staff agreed that if the Commission approves this Settlement Agreement, the Company will file revised rate schedules to produce an annual increase in base rate revenues of $940,000 for electric service rendered on and after June 1, 1986.

Article II. Treatment of "Net Negative Salvage Costs"

A. The Company has several electric plants (Knife River and Dakota Stations, Ellendale diesel, Glendive steam, Mobridge diesel, Williston steam and Bismarck) which recently have been or soon shall be retired. The settlement revenues reflect an allowance for "net negative salvage" costs which represents an estimate of the net cost of dismantling the plants. Company and Staff agree that notwithstanding the present uncertainty regarding costs of dismantlement, it is desirable to recognize some level of costs in current rates and have therefore agreed to establish, in order to ensure fairness to both ratepayers and

Company, a "tracking" procedure for the "net negative salvage" costs.

The operation of the "tracking" procedure shall be as follows:

1) Company shall record and make available for Commission inspection all costs related to the dismantling of the above-named plants.

2) At the time of the next filing for an increase in electric rates and all subsequent filings as necessary, there shall be made a comparison of costs recovered on the basis of a five year amortization ($54,452 on an annual basis in the current docket) and actual dismantlement costs incurred by Company.

3) Any over/underrecovery as determined in paragraph 2) shall then be ratably amortized as a cost of service item over the remaining period of amortization, or over an extended period if necessary in order to achieve balancing. The average balance of the over/underrecovery, as computed with regard to the subsequently established amortization period, shall be made a portion of the rate base.

4) This procedure shall cease when over/underrecovery of dismantlement-related costs of the above-named plants has essentially been zeroed out.

B. The annual depreciation rates applicable to the Company's steam generating facilities (Coyote, Big Stone, Heskett and Lewis & Clark generating stations) shall remain unchanged from rates currently being used. Annual depreciation rates applicable to other properties applicable to this proceeding shall be revised to reflect those rates proposed in the company's application.

ARTICLE III. General Conditions

A. It is agreed that this Agreement is a negotiated dollar settlement and that it established no principle or precedent. Except for the commitments established in Article II, this Agreement shall not foreclose the Company or Staff or any other person from making any contention in any proceedings or investigation, including the right of the Staff or any other interested party to seek a rate change if justified on any basis.

B. Approval of this Settlement Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this proceeding except for Article II.

C. Discussions among Company and Staff which produced this Settlement Agreement have been conducted with a customary understanding that all offers of settlement and discussions related thereto are privileged and shall not be used in any manner in connection with this proceeding or otherwise, except as required by law.

D. This Settlement Agreement includes the entire settlement and is expressly conditioned upon the Commission's acceptance of all of its provisions, without change or condition unacceptable to either party. In the event the Commission imposes any change or condition which is unacceptable to any party, this Settlement Agreement shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding and shall not be used for any other purpose.

E. This Settlement Agreement shall be binding upon the parties hereto, and upon their successors, assigns, agents and representatives.

F. It is understood that Company and Staff entered into this Settlement Agreement for the benefit of the Company's electric service customers which are located in the State of South Dakota.

This Settlement Agreement is entered into by and between Company and Staff and their respective agents, who represent that they are fully authorized to do so on behalf of their principals.

STAFF OF THE SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION

BY: Diane M. Patrick

Date: May 5, 1986

MONTANA-DAKOTA UTILITIES CO.

BY: _____

Date: May 5, 1986

THE STATE OF WYOMING

DAVE FREUDENTHAL
GOVERNOR

REC'D
JUN - 1 2010
REGULATORY AFFAIRS

Public Service Commission

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COMMISSIONERS
ALAN B. MINIER, Chairman
STEVE OXLEY, Deputy Chairman
KATHLEEN "CINDY" LEWIS, Commissioner

CHRISTOPHER PETRIE
Secretary and Chief Counsel
DARRELL ZLOMKE
Commission Administrator

May 26, 2010

Bruce S. Asay
Associated Legal Group, LLC
1807 Capitol Ave., Suite 205
Cheyenne, WY 82001
(CERTIFIED MAIL)

Re: IN THE MATTER OF THE AMENDED APPLICATION OF MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC., FOR A GENERAL RATE INCREASE IN ITS WYOMING ELECTRIC UTILITY SERVICE RATES OF $5,053,756 PER ANNUM - DOCKET NO. 20004-81-ER-09 (RECORD NO. 12259)

Dear Mr. Asay:

Enclosed is a copy of the Commission's *Memorandum Opinion, Findings and Final Order* in the above docketed matter.

Should you have any questions regarding this matter, please contact the undersigned at (307) 777-7427.

Sincerely,

DAVID J. LUCERO
Assistant Secretary

DJL/mtb
Enclosure
cc: Donald R. Ball, Vice President-Regulatory Affairs, Montana-Dakota Utilities Co.
400 North Fourth Street, Bismarck, ND 58501
Rita A. Mulkern, Regulatory Analysis Manager, Montana-Dakota Utilities Co.
400 North Fourth Street, Bismarck, ND 58501
Daniel S. Kunz, Associate General Counsel, MDU Resources Group, Inc.
P.O. Box 5650, Bismarck, ND 58506-5650
Ivan H. Williams, Senior Counsel, Office of Consumer Advocate
2515 Warren Avenue, Suite 304, Cheyenne, WY 82002
David Kinskey, Mayor City of Sheridan, 55 Grinnell Plaza, Sheridan, WY 82801
Bill Bensel, Chairman of the Wyoming Water Development Commission

Regulatory Affairs Dept.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE AMENDED APPLICATION OF MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC., FOR A GENERAL RATE INCREASE FOR ITS WYOMING ELECTRIC UTILITY SERVICE RATES OF $5,053,756 PER ANNUM	)	Docket No. 20004-81-ER-09 (Record No. 12259)

APPEARANCES

For the Applicant, Montana-Dakota Utilities Co. (MDU or the Company):
BRUCE S. ASAY of Associated Legal Group, Cheyenne, Wyoming.

For the Intervenor, Office of the Consumer Advocate (OCA):
IVAN H. WILLIAMS, Senior Counsel, Cheyenne, Wyoming.

MEMBERS OF THE PUBLIC APPEARING *PRO SE*

STEVE MAIER, Chairman of the Sheridan County Commission
BILL BRADSHAW, Chairman of the Sheridan School District Board of Directors
CRAIG DOUGHERTY, District Superintendent, Sheridan School District
DAVE KINSKEY, Mayor, City of Sheridan
BILL BENSEL, Sheridan, Wyoming
MARYANN BURTON, Trustee of the Sheridan School District No. 2
ED JOHLMAN, CFO, Sheridan Memorial Hospital
LES ENGELTER, AARP, Sheridan, Wyoming
BOB ORRELL, Trustee, Sheridan Public Library
JILL MORRISON, Powder River Basin Research Council
DAVID KANE, Sheridan County Stock Growers
ROB FORISTER, Facilities Manager, Sheridan Memorial Hospital
MIKE NIKE, Sheridan County Commissioner,
and numerous other MDU customers

HEARD BEFORE

Chairman ALAN B. MINIER
Deputy Chairman STEVE OXLEY
Commissioner KATHLEEN A. LEWIS

STEVE MINK, Assistant Secretary, and DAVID J. LUCERO, Attorney Supervisor
Presiding pursuant to a *Special Order* of the Commission

MEMORANDUM OPINION, FINDINGS AND FINAL ORDER
(Issued May 26, 2010)

This matter is before the Wyoming Public Service Commission (Commission) upon the amended application of MDU for authority to increase its Wyoming electric utility service rates in the amount of $5,053,756 per annum, on the intervention of the OCA and the comments and

representations of the members of the public appearing *pro se* herein. The Commission, having reviewed the original application and attached exhibits, the amended application and attached exhibits, the evidence of record, the *Stipulation and Agreement (Stipulation),* its files regarding MDU, applicable Wyoming utility law, and being otherwise fully advised in the premises, hereby FINDS AND CONCLUDES:

Findings of Fact: Parties and Procedure

1. On August 14, 2009, MDU filed its original application, together with pre-filed testimony and exhibits and revised tariff sheets, requesting authority to increase its retail electric utility service rates in Wyoming by $6,198,501 per year, or an overall average increase of 30.7%. MDU stated the proposed rate increase was necessary to recover its 25% ownership interest investment in the Wygen III generating unit (Wygen III or the Plant). MDU noted it received a Certificate of Public Convenience and Necessity (CPCN) to participate in the Wygen III coal-fired electric generating unit in Docket No. 20004-72-EA-08. The certificate authority made no determinations regarding any ratemaking issues associated with MDU's participation in the generating unit. The Company stated that Wygen III was expected to be completed and ready for commercial operation in the second quarter of 2010. MDU stated its investment in Wygen III secures a reliable long-term supply source for a portion of the electric requirements for the Company's Sheridan System. MDU stated that it currently purchases its energy and capacity requirements for its Wyoming electric customers through a purchased power contract with Black Hills Power, Inc. (Black Hills). MDU stated that, when the purchased power contract expires in 2016, its customers will become exposed to uncertain and potentially volatile wholesale power costs. Participation in WYGEN III will help protect its customers from future wholesale market volatility.

2. MDU stated that its net rate base would increase by approximately $62 million upon completion of Wygen III, reflecting the Company's 25% ownership interest in the Plant, together with increased operation and maintenance (O&M) expenses associated with the Wygen III facility, but net of a reduction in purchased power costs under its current full requirements contract with Black Hills. The Company estimated the rate impact in Wyoming would be approximately $6,198,501 annually or an overall average increase of 30.7% based on a 2008 pro forma test year. The test year in this case consisted of the 12 month period ending December 31, 2008. MDU stated that its existing rates were unjust, unreasonable, and not compensatory, and therefore should be increased as requested to allow the Company to earn an adequate return on its investment in Wygen III.

3. MDU proposed to recover the requested revenue increase from its various customer classes in the following amounts and percentages:

Class	Increase	Percentage Change
Residential	$2,968,001	26.1%
Small General Service	$1,552,124	41.3%
Irrigation Service	$70,255	26.9%
Large General Service	$1,579,743	34.5%
Lighting	$28,378	16.7%
Overall Increase	**$6,198,501**	**30.7%**

4. With its application, MDU filed the prepared direct testimony of David L. Goodin, J. Stephen Gaske, Darcy J. Neigum, Garrett Senger, Rita A. Mulkern, and Tamie A. Aberle, together with supporting exhibits, studies, and other documentation for the case.

5. On August 17, 2009, the Commission issued its *Suspension Order* suspending the Company's rates in this case for investigation and further action for the initial six-month period provided in W.S. § 37-3-106(c), which commences after the 30-day notice term provided in subsection (b) thereof.

6. On August 25, 2009, the Commission issued its *Notice of Application*, providing for an intervention, comment and protest deadline of September 25, 2009. The *Notice of Application* was published once a week for two consecutive weeks in the *Sheridan Press* and a public service announcement was aired five times a week for two weeks on KROE-AM in Sheridan.

7. The OCA filed its *Notice of Intervention* on August 25, 2009, and requested the application be set for public hearing. No other formal -- and timely -- intervention petitions were filed.

8. On September 24, 2009, MDU customers filed with the Commission a petition bearing numerous customer signatures, opposing the proposed rate increase and requesting a public hearing be held in the Sheridan area. Throughout the course of these proceedings, numerous MDU customers filed comments opposing the general rate increase or the proposed increase to the Irrigation class. Some of the customer comments also requested that a public hearing be held in Sheridan. Copies of all customer comments and requests for a public hearing were provided to MDU and OCA.

9. On October 15, 2009, the Commission issued its *Notice of Setting Scheduling Conference* which set a scheduling conference for November 4, 2009, in the Commission's hearing room in Cheyenne, Wyoming.

10. On October 20, 2009, the Commission issued its *Special Order Authorizing One Commissioner and/or Hearing Examiner to Conduct Public Hearing.*

11. The duly noticed scheduling conference was held on November 4, 2009. Bruce S. Asay, local counsel for MDU, participated in person. Rita Mulkern and Tamie Aberle for MDU participated by telephone. Ivan Williams, counsel for the OCA, and David Lucero, Steve Mink and Marci Norby, of the Commission Staff, participated in person.

12. On November 5, 2009, the Commission issued its *Scheduling Conference Order (Scheduling Order)* which established a procedural schedule agreed to by the parties at the scheduling conference, including a public hearing commencing on February 23, 2010, in the Commission's hearing room in Cheyenne, Wyoming.

13. The Commission issued its *Procedural Notice and Order Setting Public Hearing* on November 10, 2009 (*Procedural Order*). It set a public hearing to commence on February

23, 2010, in the Commission's hearing room in Cheyenne, and provided for the filing of written public comments by February 23, 2010. It was published once per week for two consecutive weeks in the *Sheridan Press* and a public service announcement was aired five times a week for two weeks on KROE-AM in Sheridan.

14. To accommodate the requests of MDU customers for a Sheridan public hearing, the Commission issued its *Procedural Notice and Order Setting Public Comment Hearing* on December 9, 2009, setting a public comment hearing to commence on February 10, 2010, at the Sheridan Public Library. It was published once per week for two consecutive weeks in the *Sheridan Press* and a public service announcement was aired five times a week for two weeks on KROE-AM in Sheridan.

15. On December 30, 2009, Dave Kinskey, Mayor of the City of Sheridan (the City), filed a letter offering the Sheridan City Council Chambers as a location for the February 10, 2010, public comment hearing as it is equipped with a camera system which allows for live broadcast, recording and rebroadcasting on the City's local government channel. He stated there was a tremendous amount of interest in MDU's proposed rate increase and it would be beneficial to the public to be able to broadcast the hearing. On January 4, 2010, via electronic mail, the parties were advised that the location of the public comment hearing had changed and would now be held in the Sheridan City Council Chambers.

16. On January 14, 2010, MDU filed its supplement to application *(Amended Application)* together with appendices, exhibits and statements, which had the effect of amending the Company's original application. MDU stated that, after a review of the applicable federal authority, it believed it was entitled to take certain bonus depreciation deductions for Wygen III. The *Amended Application* was filed to reflect bonus depreciation deductions associated with Wygen III expenditures that reduced the revenue increase found in the Company's original application from $6,198,501 per annum (30.7 % overall) to $5,053,756 per annum (25.1% overall).

17. The amended rate increase was proposed to be recovered from the various customer classes by the following amounts and percentages:

Class	Increase	Percentage Change
Residential	$2,414,230	21.2%
Small General Service	$1,296,410	34.5%
Irrigation Service	$55,496	21.2%
Large General Service	$1,263,787	27.6%
Lighting	$23,833	14.0%
Overall Increase	**$5,053,756**	**25.1%**

18. On January 19, 2010, OCA pre-filed the direct testimonies and respective exhibits of Denise Kay Parrish, Amy J. Zamora and Kimber M. Wichmann.

19. On January 21, 2010, the Commission issued its *Amended Procedural Notice and Order Setting Public Hearings* (*Amended Procedural Order*). The *Amended Procedural Order* gave notice that the Company's original application had been amended and the amount of the

proposed revenue increase and the recovery of the proposed increase from the various customer classes had also been revised. Further, the notice provided that the February 10, 2010, public comment hearing to be held at the Sheridan Public Library had been relocated to Sheridan Community College. The *Amended Procedural Order* also provided additional notice of the public hearing already scheduled to commence on February 23, 2010, in the Commission's hearing room in Cheyenne. It was published once per week for two consecutive weeks in the *Sheridan Press* and a public service announcement was aired five times a week for two weeks on KROE-AM in Sheridan. A display ad announcing the Sheridan public comment hearing was also published in the *Sheridan Press* on February 4 and 8, 2010. Copies of the *Amended Procedural Order* were also sent to customers who submitted comments or requests for hearing in this matter.

20. On January 20, 2010, the City filed, via facsimile, a *Petition for the City of Sheridan for Leave to Intervene Out-of Time (Late-Filed Petition)* stating, *inter alia*, that it did not have adequate notice of MDU's application. The City requested that it be allowed to intervene out-of-time and respond to MDU's application, via pre-filed testimony. A signed hard copy of the *Late-Filed Petition* was filed on January 21, 2010. The City filed a *First Amended Petition of the City of Sheridan for Leave to Intervene Out-of-Time* via facsimile, on January 22, 2010, and a signed hard copy of the *First Amended Petition* on January 25, 2010. The *First Amended Petition* was signed by the City's counsel, Robert P. Warburton of Sheehan, Sheehan & Stelzner, P.A., a licensed Wyoming attorney.

21. On January 25, 2010, MDU filed the *Supplemental Testimony of Witnesses Rita A. Mulkern and Tamie A. Aberle*, in support of the amended application.

22. On January 27, 2010, MDU filed its *Objection of Montana-Dakota Utilities Co. To the Petition of City of Sheridan, Wyoming to Intervene (Objection)*. The City's *First Amended Petition* and MDU's *Objection* came before the Commission for consideration pursuant to due notice at its open meeting of January 27, 2010. Based on the arguments of the parties and its finding that the City had not shown good cause for the failure to timely request intervention, the Commission denied the City's intervention request by *Order Denying Intervention* issued on February 23, 2010. The Commission strongly encouraged City representatives to participate in this proceeding through the presentation of oral comments at the public hearings in this matter or by providing written comments as provided for in Commission Rule Section 103 (g).

23. On February 5, 2010, MDU filed its Electric Division Depreciation Study and its Common Plant Depreciation Study, both as of December 31, 2008, and depreciation testimony of Rita A. Mulkern.

24. On February 9, 2010, MDU filed the rebuttal testimony of Dr. J. Stephen Gaske, Rita A. Mulkern and Tamie A. Aberle.

25. On February 10, 2010, and pursuant to due public notice, a public comment hearing was held in Sheridan. MDU and OCA witnesses provided brief summaries of their

respective positions and members of the public were invited to offer comments. Numerous customers offered their comments during this public comment hearing.

26. Pursuant to the *Scheduling Conference Order* issued on November 5, 2009, the Commission held a pre-hearing conference on February 12, 2010, in the Commission's hearing room in Cheyenne, Wyoming. On that day, [i] OCA filed its *Updated Summary of Contentions, Designation of Exhibits* and *Summary of Remaining Issues*; and MDU also filed its *Scheduling Conference Memo For Montana-Dakota Utilities Co., A Division of MDU Resources Group, Inc.* The Commission issued a *Prehearing Conference Order* on February 19, 2010.

27. On February 16, 2010, MDU filed its *List of Exhibits* and *Summary of Contentions*.

28. On February 17, 2010, OCA filed its *Amended Designation of Exhibits*. Transcripts of the February 10, 2010, public comment hearing were also received in the Commission's office on February 17, 2010.

29. A public hearing in this matter was held on February 23-25, 2010, in Cheyenne. MDU and OCA appeared and participated in the hearing. MDU presented its case through six witnesses, David L. Goodin, Dr. John Stephen Gaske, Garrett Senger, Darcy Neigum, Rita Mulkern and Tamie Aberle. OCA presented its case through three witnesses, Denise Kay Parrish, Amy J. Zamora and Kimber Wichmann. Public comments were provided by MDU's customers.

30. On March 3, 2010, MDU filed its Late-Filed Exhibit Nos. 157 and 158. Exhibit No. 157 provides support for the Company's calculation of the allowance for funds used during construction (AFUDC) as of December 31, 2009, shown on MDU Exhibit No. 139. Exhibit No. 158 supports MDU's share of the Shared Assets, Ground Lease and Administrative Fee shown on MDU Exhibit No. 139.

31. On March 5, 2010, MDU filed the *Stipulation*, the affidavit of David L. Goodin, and the testimony of Rita A. Mulkern and Tamie A. Aberle in support of the *Stipulation*; and OCA filed Amy J. Zamora's testimony in support of the *Stipulation*. In the *Stipulation*, MDU and OCA agreed, *inter alia*, to an increase in the Company's Wyoming jurisdictional retail electric service revenues in the amount of $3,253,726 per annum, effective for service rendered on and after May 1, 2010, with the increase to be phased in over a three-year period.

32. The Commission issued its second *Suspension Order* on March 9, 2010, suspending the Company's rate increase request for the final three-month period provided for in W.S. § 37-3-106(c). Also on this date, the Commission issued its *Procedural Notice and Order Reopening Record and Setting Additional Public Hearing*. It set an additional public hearing to commence on March 22, 2010, in Cheyenne. At this additional public hearing, the Commission expressed its intent to receive into the record [i] the *Stipulation*, [ii] the testimony and exhibits of MDU and OCA in support of the *Stipulation*, and [iii] further public comment. The *Procedural Order* was published on March 13 and 17, 2010, in the *Sheridan Press* and a public service announcement was aired five times on KROE-AM in Sheridan during the week of March 14-21,

2010.

33. On March 12, 2010, MDU filed its Late-Filed Exhibit No. 159 which provides the detailed class of service study and work papers underlying MDU Exhibit No. 130. On March 15, 2010, the OCA and MDU filed their *Joint Responses to Stipulation Data Requests.*

34. On March 16, 2010, OCA filed Exhibit AJZ-1 as referenced in the *Stipulation Testimony of Amy J. Zamora on Behalf of the Wyoming Office of Consumer Advocate,*

35. On March 16, 2010, transcripts of the hearings held on February 23-25, 2010, were received in the Commission's offices. Parties were notified on March 17, 2010, via electronic mail, that the transcripts were received and post hearing briefs were due on or before April 7, 2010.

36. On March 22, 2010, the Commission held an additional public hearing in Cheyenne, reopening the record for purposes of receiving the *Stipulation* and the testimony and exhibits of the parties in support thereof. MDU offered the testimony of its witnesses, Rita Mulkern and Tamie Aberle. OCA offered the testimony of Amy J. Zamora.

37. On April 7, 2010, MDU and OCA filed their *Combined Post-Hearing Brief.*

38. On April 8, 2010, transcripts of the hearing held March 22, 2010, were received in the Commission's offices. Parties were notified on April 8, 2010, via electronic mail, that public deliberations would be held on April 14, 2010, in the Commission's hearing room.

39. Pursuant to W.S. § 16-4-403, the Commission held public deliberations on April 14, 2010, rejecting the *Stipulation* and the rate increase reflected therein, approving *inter alia,* a general rate increase of $2,651,565 per annum and directing the preparation of an *Order* consistent with its deliberations.

40. As directed by the Commission at deliberations, MDU submitted on April 23, 2010, its compliance tariff sheets consistent with the deliberations of the Commission. The tariff sheets were approved at the Commission's open meeting of April 27, 2010, to be effective for service rendered on and after May 1, 2010.

Findings of Fact: Party Positions

Summary of MDU's evidence

41. Mr. David Goodin, President and CEO of MDU, provided a summary of his prefiled testimony (MDU Exhibit No. 100) in support of the Company's amended application. He discussed the amended application and provided a policy statement and justification for MDU's rate increase request. Goodin testified that the requested general rate increase of $5,053,746, or 25.1% in the Company's Wyoming electric rates is based on a 2008 test year adjusted for known and measurable changes. Goodin stated MDU was requesting a rate increase to recover its investment in Wygen III explaining the Plant secures a reliable supply source for a

portion of MDU's electric requirements. Goodin explained that the overall rate increase and revenue requirement will reflect customer class percentage rate changes as follows:

Class	Percentage Change
Residential Rates Schedules 10 and 18	21.2%
Small General Service	34.5%
Irrigation Service	21.2%
Large General Service	27.6%
Municipal; Lighting	14.0%
Overall Increase	**25.1%**

(Tr., pp. 140-141.)

42. Goodin stated MDU currently purchases its energy and capacity requirements through purchased power agreements (PPAs). MDU's current full requirements contract with Black Hills, which commenced on January 1, 2007, was filed in Docket No. 20004-65-EP-06 (Sub 65). This full requirements contract expires December 31, 2016, and contains an option for MDU to purchase up to 25 megawatts from Black Hills' Wygen III generating unit. Goodin stated that MDU exercised that option and purchased a 25% ownership interest in the Plant to serve its Wyoming electric service customers. MDU also filed an application for a Certificate of Public Convenience and Necessity (CPCN) in Docket No. 20004-72-EA-08 (Sub 72) for participation in Wygen III, which has an expected in service date of April 1, 2010. Goodin testified that, upon completion of the Plant, the Company's net rate base will increase by approximately $62 million to reflect its 25% interest ownership together with the increased O&M expenses associated with the facility, offset in part by a net reduction in power purchase costs under the current full requirements contract with Black Hills. He stated that MDU's participation in the Plant will help protect its ratepayers from the volatile energy market by providing a cost-effective resource and bring diversity to the Company's resource mix by including Company-owned generation with power supply purchases, rather than being totally dependent on PPAs. He discussed how the electric resource modeling process used in the CPCN application took into account possible carbon legislation (cap and trade), carbon costs and pollution considerations. The Company's electric resource analysis demonstrated that a combination of Wygen III, demand side management (DSM) and supplemental purchased power would provide an adequate, reliable and economic electric supply. Goodin also discussed MDU's efforts to employ technological advances to streamline its business practices and its utility integration efforts to become more efficient and save money. He testified to the benefits and risks to the Company in owning a partial interest in the Plant. He also discussed how the Company's ownership and investment of monies increases the risk to ratepayers and the reasons the Company took on the increased risk as a result of its investment in Wygen III. (Tr. pp. 141-144, 150-151, 153-159; MDU Exhibit No. 100, pp. 10-12.)

43. Dr. John Stephen Gaske, Senior Vice President of Concentric Energy Advisors, provided a summary of his prefiled testimony including attached supporting exhibits. (MDU Exhibits 101-102.) Gaske's testimony addressed his analyses in support of his suggested cost of common equity capital of 12.75% for MDU's Wyoming electric utility operations. Gaske stated he calculated the cost of common equity capital based on Discounted Cash Flow (DCF) analyses of a proxy company group with risks similar to those of MDU's Wyoming electric operations.

He stated the purpose of the DCF analysis is to find the discount rate or the cost of capital that is implicit in the stock price of any given utility and reflects what investors expect to receive from their investment in the future. He stated the DCF analysis is a straightforward approach for estimating the cost of capital. Gaske testified he conducted two different DCF analyses: [i] a basic DCF analysis that relies on investment analysts' estimates for the growth rate; and [ii] a two-step growth rate estimation model that combines investment analysts' growth rates with forecasts of the earnings retention growth rates of companies. He also performed Risk Premium and Alternative Equity Investment analyses in establishing benchmarks for a reasonable rate of return. Gaske argued that the results of his DCF analyses must be adjusted by a flotation factor to account for issuance costs for new common equity capital. He used a flotation adjustment factor of 3.7% which he based upon the average cost of a representative sample of flotation costs incurred by electric companies for 81 new common stock issuances during the period 2000-2009. Gaske stated he used a group of 13 proxy companies that have similar risks to those of MDU's Wyoming electric utility operations. He discussed his belief that the OCA's proxy companies were less comparable to MDU than his proxy companies, stating it was more important to have companies as comparable as possible than it is to have a larger group of companies as proposed by OCA. Gaske discussed his 13 proxy companies stating, *inter alia*, he chose companies that [i] have at least 85% of their invested assets dedicated to electric utility operations; [ii] derive at least 25% of their generation from coal-fired plants; and [iii] have investment grade bond rating, [iv] paid dividends and [v] have published growth rate estimates provided by investment analysis services. He acknowledged that a true proxy company does not exist. (Tr., pp. 168-171, 175-176, 188-191; MDU Exhibit No. 101, pp. 3, 9, 16.)

44. Gaske testified that, in a DCF analysis, the dividend yield portion of the equation is simple to calculate but the future growth rate component is more difficult to estimate. His basic DCF analysis, which relied solely on investment analysts' forecasts for determining the growth rate component, resulted in a median cost of equity of 12.73%, an average cost of 12.91%, and a proposed return of 12.95%. Gaske testified that his two-step DCF growth rate estimation analysis, which ascribes two-thirds weight to investment analysts' forecasts and one-third weight to Value Line's retention growth rates for his proxy companies, resulted in a median cost of capital of 11.56% with an average for the group of 12.1% and a 12.62% return. He stated it was his opinion, given the slightly above average risk of MDU's Wyoming electric operations, that the required rate of return on common equity for MDU's Wyoming electric operations is approximately 12.75%. He discussed how the rate of return for MDU's Sheridan system affects the overall Company and he acknowledged that the 12.75% rate of return is higher than normal. Gaske explained that with the stock market down, investors require a higher rate of return because they perceive more risks in investments. Gaske stated the decrease in stock prices in the market increased his current DCF analysis results versus what the result would have been two years ago. (Tr., pp. 172-178, 186-187, 192-195.) He discussed the different risks faced by utilities and investors, the additional risk to a company of having coal-generated resources in its portfolio, and the differences in the risk associated with having an ownership interest in Wygen III and entering into PPAs. He stated that with PPAs more risk falls on the ratepayers and with an investment in its own plant, a company assumes more of the risk than would the ratepayers. (Tr., pp. 179-182, 188-191, 194-203, 206-212.)

45. During cross examination and in his rebuttal testimony (MDU Exhibit No. 135),

Gaske criticized OCA witness Kimber Wichmann's proxy company selection and screening criteria, to include what he termed her failure to limit her proxy group to coal-fired generation assets, and her exclusion of companies with bond ratings above MDU's, while including companies with bond ratings below MDU, and her use of comparable companies with electric operating revenue of 70% or more, whereas his threshold was 85% of electric revenues. Further, he disagreed with her application of the constant growth and two-stage DCF models, her use of the Capital Asset Pricing Model as a method of estimating the cost of common equity capital, and her use of a partial flotation cost adjustment. (Tr., pp. 179-186; MDU Exhibit No. 135, pp. 4-5, 29-39, 53-54.)

46. Gaske also offered a summary of his rebuttal testimony (MDU Exhibit No. 135) responding to OCA witness Denise Parrish's proposal to levelize the cost of the returns on Wygen III over the OCA's recommended expected 50-year depreciable life of the Plant, in contrast to traditional ratemaking wherein the return is earned on the net value of the Company's rate base each year. He stated the OCA's proposal would deny MDU an opportunity to earn a fair return on its investment in Wygen III. He stated, under OCA's proposal, common equity investors would be allowed to only earn a 3.20% return on Wygen III during the first year as compared to the higher returns on equity (ROE) he and Wichmann propose. He argued that ratepayers would be denied the opportunity to earn a fair rate of return on the Wygen III investment until twenty years in the future. He stated that OCA's proposal does not provide: [i] a rate of return sufficient to assure the financial integrity of the Company, [ii] sufficient revenue to cover the financial costs of the utility, or [iii] a return comparable to similar investments of like risk. He stated OCA's proposal deprives common equity investors of approximately $8.7 million in present value dollars that would otherwise be available to them under a normal rate of return on rate base calculation. Regarding levelization and cash flow, Gaske stated Parrish did not look at what effect levelization would have on the equity holders; she only looked at the overall rate of return. Gaske stated his calculation illustrated that levelization would cover the debt service but would substantially cut the equity return. (Tr., pp. 719-720, 729-731; MDU Exhibit No. 135, pp. 2-3, 6-8, 12.)

47. Gaske stated that Parrish's levelized proposal incorrectly assumes investors will be reimbursed for the cost of their capital 50 years from now. Gaske stated that, during the proposed 50-year levelization period, much of the equipment will be replaced or refurbished because the levelization period exceeds the life of many of the assets. Further, the overall rate of return of 8.45% utilized in her levelization proposal is too low in comparison to the Company's proposed overall rate of return. He stated Parrish failed to recognize that interest on the debt must be paid before the equity investors receive any return. He stated that, under the OCA's proposal, most of the overall return dollars available in the early years will be paid as interest to the debt holder and more equity returns will be pushed out to the later years and will not provide full compensation for the time value of their deferred investment. Gaske stated that, for the equity holders to actually stay whole under Parrish's levelized overall rate of return of 8.45%, the bondholders would have to agree to defer their receipt of interest. He discussed further complications that would need to be considered when considering a levelized approached. (Tr., pp. 719-720, 737-742; MDU Exhibit No. 135, pp. 4.)

48. Gaske noted Parrish's proposal does not recognize or account for the significant

increase in business and regulatory risks that would be caused by OCA's recommendations. He stated that the Company's auditor advised him that OCA's proposal would not qualify for SFAS 71 treatment in the recording of a regulatory asset. He stated MDU's auditor advised him that you can defer an expense item but you cannot record deferrals for revenue items. (Tr., pp. 732-734.)

49. Mr. Darcy Neigum, MDU Systems Operations and Planning Manager, [i] provided a summary of his prefiled testimony (MDU Exhibit No. 103) which offered an overview of Wygen III, [ii] discussed the Company's March 2008 Integrated Resource Plan (IRP) filed as part of its CPCN application in the Sub 72 proceeding, and [iii] described how Wygen III worked in conjunction with the current Black Hills' PPAs. He stated the Plant was expected to be fully commercial and operational on or around April 1, 2010. He discussed the three main areas the IRP encompassed: [i] a load forecasting update; [ii] a Demand Side Management update; and, [iii] a supply-side update which included a market analysis of the estimated energy market. Neigum also discussed MDU's long-term coal supply agreement with Wyodak Resources for Wygen III, its terms and how the coal would be transported from the Wyodak Mine to Wygen III. He discussed the benefits of the Plant, stating they occur over the long term and include, *inter alia*, protection for Wyoming rate payers from wholesale market volatility. He stated participation in Wygen III provides MDU with ownership of a stable and cost-effective resource, brings diversity to its resource mix, and provides a more stable power supply to the customers' benefit. Neigum testified that, in conjunction with MDU's 25% ownership in Wygen III, the Company executed an amendment to its full requirements PPA with Black Hills to service its Sheridan load. The amended PPA runs through December 16, 2016. He stated MDU will be required to use its ownership share of the Wygen III output or rely on replacement power to serve the Sheridan load. Neigum further explained that, following the commercial operation of Wygen III, the PPA will supply all needed resources above those provided by the Company's share of the Plant up to 74 MW. (Tr., pp. 219-224, 226-228, 241, 266-268, 278-280.)

50. Neigum discussed differences in Wygen III construction costs (and the reasons therefor) between those presented in the Sub 72 certification proceeding and those presented in this matter. He testified that MDU's current updated estimate for the total project cost, with the projected AFUDC and remaining capital expenditures for 2010, is $63,354,500 as of December 31, 2009. (MDU Exhibit No. 139.) He discussed the changes to O&M expenses, and administrative and general expenses (A&G) associated with Wygen III as estimated in Sub 72 and as presented in this case, stating the O&M costs in this case are based on Wygen II costs. Neigum also discussed MDU's ability to oversee the ongoing Wygen III O&M and A&G expenses. He discussed the administrative costs Black Hills charges the Company stating there were two types of costs: [i] directly assigned costs, and [ii] administrative costs. He further stated coal prices related to fuel costs for Wygen III had also decreased from the last update and were projected at $11.70 per ton for the year 2010. Neigum also testified he believed a 40-year depreciable life for Wygen III was reasonable. He noted that the coal supply agreement for Wygen III is for 50 years. He stated it was hard to predict how long a plant could operate given the technologies used to build it and how it has been run. Neigum noted that MDU has several coal resources that have operated for 50 years. Finally, Neigum described the costs kVARS impose on the Company's system. (Tr., pp. 226-239, 245, 253-255, 263, 280-283; MDU Exhibit

No. 103, pp. 8-9.)

51. Mr. Garrett Senger, MDU's Vice President-Controller and Chief Accounting Officer, provided a summary of his prefiled direct testimony (MDU Exhibit No. 104), in support of the Company's calculation of the overall cost of capital, capital structure, debt and preferred equity cost. He also discussed Statements A, B and F, attached to the Application. (MDU Exhibits 105, 106 and 107.) Statement A is the balance sheet for MDU as of December 31 for the calendar years ended 2007 and 2008, and accompanying notes to the financial statements. Statement B reports the income statement for the 12 months ended December 31, 2008, and March 31, 2009. Statement F shows the utility's capital structure at December 31, 2008, and a pro forma capital structure for 2009, as well as the associated costs of debt, preferred stock, and Gaske's proposed common equity cost. Senger testified that the pro forma capital structure and the associated costs serve as the basis for the overall requested rate of return of 9.62%, which is comprised of:

Component	Percentage	Cost	Weighted cost
Long-term Debt	44.959%	6.793%	3.054%
Average Short-term Debt	2.771%	3.773%	0.105%
Preferred Stock	2.5%	4.594%	0.115%
Common Equity	49.77%	12.75%	6.346%
TOTAL	100.00%		9.62%

He also discussed the pro forma capital structure and the differences between the pro forma and the per books capital structures as of December 31, 2008. (Tr., pp. 287-291.)

52. Senger also addressed the Company's calculation of the AFUDC related to Wygen III, stating it was calculated pursuant to the prescribed FERC Uniform System of Accounts formula which is comprised of two components: [i] borrowed funds used during construction and, [ii] other funds used during construction comprised of debt and equity. He stated that MDU applies AFUDC to construction projects that are greater than 60 days in length. Senger also discussed how the AFUDC was calculated for 2010, stating the AFUDC will be accrued until the Plant is in service. He referenced MDU Exhibit No. 139 which showed AFUDC in the amount of $1.8 million for 2010. (Tr., pp. 457-462.)

53. Ms. Rita A. Mulkern, MDU's Regulatory Analysis Manager, provided a summary of her prefiled direct and supplemental testimony, including attached supporting exhibits. (MDU Exhibits No. 108 and 126.) Mulkern's testimony addressed [i] the Company's revenue requirement and per books cost of service for the 12 months ending December 31, 2008, [ii] the pro forma cost of service reflecting known and measurable adjustments that would occur by December 31, 2009, including the Company's 25 MW investment in Wygen III, and [iii] the calculation of MDU's revenue deficiency. She also sponsored Statements C-E and G-L. (MDU Exhibits 109-117.) She noted the pro forma cost of service is summarized in Statement L with the supporting detail contained in Statements C-K. Statement L shows the calculation of the revenue deficiency based on the overall rate of return of 9.62% from Statement F, page 1, as supported by Gaske and Senger. She stated the pro forma adjustments to the income statement, Adjustments 1-31, pertain to revenue, expense items and rate base, with Adjustments A-K

pertaining to rate base items. Adjustments relating to Wygen III included: an accumulated reserve for depreciation, accumulated deferred income taxes, fuel and purchased power, O&M, depreciation expense, and other taxes, including income taxes, that are listed separately in the statements. (MDU Exhibit No. 108, pp. 4-14.) Mulkern's testimony also addressed the Company's current power supply cost adjustment (PSCA) tariff given MDU's ownership of Wygen III for a portion of its electric requirements. She stated that MDU's PSCA tariff is an annual adjustment that specifies the procedure to use to adjust rates for fuel and purchased power and amortization of the power supply balancing account. Mulkern stated that, with the addition of Wygen III into MDU's power supply mix, the Company will still be purchasing capacity and energy from Black Hills pursuant to its PPA. The capacity and energy available from Wygen III will displace a portion of the energy and capacity from the Black Hills PPA. She stated MDU would also incur fuel expense for the coal supply required for its portion of Wygen III. Mulkern testified the current PSCA tariff language provides for the inclusion of fuel, purchased energy and capacity and any ancillary services. Mulkern expressed her belief that the addition of Wygen III could be accommodated within the existing tariff language and no changes to the tariff are needed. Mulkern noted the Company was proposing to change the calculation of the PSCA to accommodate the differences in customer class allocations and to clarify the language on the calculation of the PSCA. Mulkern testified that MDU was also proposing to add language to provide the detail of the calculation used to determine the monthly over- or under-recovered amounts placed in the balancing account. (Tr., pp. 294-296; MDU Exhibit No. 108, pp. 15-18.)

54. Mulkern also summarized her supplemental testimony revising MDU's revenue requirement to reflect its proposed bonus tax depreciation adjustment. She testified an accelerated/bonus depreciation deduction was available for federal income tax purposes for certain 2009 qualifying property additions. She stated the deduction was created in February 2008 as part of the Economic Stimulus Act of 2008 which allows for an accelerated tax deduction equal to 50% of the cost of new qualifying property purchased and placed in service in 2008. The bonus depreciation provisions were extended in 2009 under the American Recovery and Reinvestment Act to new qualifying assets acquired and placed in service in 2009. She explained the bonus depreciation accelerates the amount of tax depreciation available thereby affecting current income taxes, deferred income taxes and accumulated deferred income taxes found in rate base. She stated that it does not affect the value of Wygen III or any of its associated expenses. Mulkern testified the revised additional revenue requirement, taking into account the bonus depreciation adjustment, is $5,053,903 or $1,144,369 less than the initial requested amount. (Tr., p. 298.) Mulkern testified that at the time MDU filed this rate case, it was not certain if its investment in Wygen III would qualify for the bonus depreciation. However, after research and review of the requirements, Mulkern stated the Company now believes it satisfies the requirements; and the 2009 expenditures for Wygen III should be eligible for the bonus tax depreciation. She stated the Company intends to take the bonus depreciation in its 2009 taxes. If MDU is not eligible for the bonus depreciation, the IRS will review the Company's taxes and advise it that it is not eligible. Mulkern stated an IRS review will not take place for three or four years but the Company stands by its determination to take the bonus depreciation. (Tr., pp. 297-300, MDU Exhibit No. 126, pp. 3-4.)

55. Mulkern also addressed the Company's February 5, 2010, filing of an electric division Depreciation Study and Common Plant Depreciation Study, both as of December 31,

2008. The studies set forth the new depreciation rates for electric and common plant. They were filed in compliance with the Commission's *Order* in the Company's last general rate case (Docket No. 20004-75-ER-08 (Sub 75)) which directed the Company to file a depreciation study with its next rate case. She testified the effect of the proposed revised depreciation rates results in a decrease in the overall revenue requirement of $220,358 from the January 14, 2010, amended filing, resulting in a decrease in the Company's proposed revised revenue increase of $5,053,903 to $4,833,545. (Tr., p. 298; MDU Exhibit No. 142, pp. 2-3.)

56. Mulkern testified on rebuttal and in cross-examination on her adjustment seeking recovery of $1,683 for institutional advertising expenses from customers rather than shareholders, arguing it was appropriate because customers benefit from this form of advertising. She noted the Company serves small communities in which it is important for MDU to be involved and to demonstrate its support, all of which benefits its customers. She disagreed with OCA's proposed disallowance of this expense, stating it should be recoverable, and the Commission has the authority to consider recovery on a case by case basis. She also addressed the general inflation adjustment and the reasons MDU applied it to various expense categories. She stated the inflation adjustment is applied to smaller dollar amounts and is an aggregate adjustment to expenses using the Consumer Price Index (CPI) as the inflation factor. The CPI used by the Company is a three-year historical average. Regarding the Company's depreciation expense adjustment, she stated the Company used an annual depreciation expense on the plant additions but utilized a six month period in developing the deferred taxes, including tax depreciation, associated deferred taxes and the rate base deduction for accumulated deferred income taxes. Mulkern testified that MDU used six months of depreciation expense for plant additions because they come into service throughout the year. (Tr., pp. 301-306, 743, 753.)

57. Mulkern explained why MDU's proposed three-year amortization period for regulatory commission expense was reasonable, stating three years allows time to recover the cost from customers before the time the company may need to file another rate case. She stated this time frame will help avoid the situation where customers are paying the expenses associated with the current case and the cost of a previous case. Mulkern argued that, should rate case expenses be extended beyond the three years proposed by the Company, it would be appropriate to include the unamortized rate case expense balance in rate base to compensate the Company for the time value of money in delaying recovery of its expenses incurred in 2009. Mulkern also addressed the tariff changes MDU was proposing for its PSCA. (Appendix B to the amended application.) She stated that, under the PSCA Rate 50 tariff, the Company proposes to have three separate classes; it currently has one class applicable to all its customers. The three classes would be: [i] Primary Service for customers taking service under Rates 20 and 39; [ii] Secondary Service for customers taking service under Rates 10, 20, 24, 25 and 39; and [iii] Controlled Rates 11 and 22. MDU proposed to establish a base cost of fuel and purchased power for each of these classes in a general rate case. Then, as part of its monthly accounting, MDU would calculate the over-or-under recovery for each class separately. (Tr., pp. 312-316, 743.)

58. On rebuttal, (MDU Exhibits No. 138 and 139), Mulkern addressed certain adjustments proposed by OCA witness Zamora. She stated MDU objected to Zamora removing the $3,499 expense relating to transmission expenses. She stated that Zamora eliminated this expense as it related to a one-time occurrence. Mulkern stated that this particular activity might

be non-recurring as reflected in the transmission account, but she explained that it is not a non-recurring expense and that the expense itself, or the dollars associated with it, were not incremental. Mulkern disagreed with OCA's calculation of tax depreciation on plant additions because Zamora used a full year of book depreciation in her calculation rather than the half year used by MDU. Mulkern stated, when calculating book depreciation in the calculation of tax depreciation, the book depreciation portion is based on the actual depreciation expense on those plant additions and is neither a normalized expense nor a theoretical depreciation expense. Regarding the calculation of investment in the Plant, she stated that an update of this investment cost had been provided (MDU Exhibit No. 139), with updated amounts for coal expense and O&M expenses (MDU Exhibits 155 and 156) which are more current than the amounts utilized by OCA. She stated the Company agreed that these most recent updates should be utilized and would match the update of the Wygen III Plant value included in her Rebuttal Testimony. (Tr., pp. 743-748, 760-762.)

59. In opposition to OCA's proposed revisions to the PSCA, Mulkern testified she believed the current tariff language conforms to Commission Rules 249 and 250. She stated that the language in Rules 249 and 250 does not preclude recovery of fuel associated with a generation unit and they do not address what is prohibited. Regarding the use of a dead band, Mulkern stated the Company did not agree with Zamora's recommendation to use a base fuel cost with a dead band and a sharing over/under the dead band. She explained that the components of MDU's PSCA include a contract that was filed with and approved by FERC and this Commission, which contains an escalation factor. She stated it was not appropriate at this time to determine whether the escalation factor is recoverable. The PSCA also includes a transmission component, which is a FERC-regulated tariff with a regulated rate. She stated it was not appropriate to establish a dead band that would preclude recovery of that amount. Mulkern further stated the coal contract (Statement R) includes a price for coal that is not negotiated but is a rate filed with and approved by the South Dakota Commission. Mulkern stated that, because the PSCA contains rates that are established or regulated, it would not be appropriate to establish a dead band that would preclude recovery of the costs. (Tr., pp. 748-754.)

60. Tamie A. Aberle, MDU's Pricing and Tariff Manager, provided a summary of her prefiled testimony and attached exhibits (MDU Exhibits No. 108, 119-125, 130-134), in support of the Company's rate design and the embedded class cost of service study. She discussed the results of the class cost of service study and the proposed design of rates to recover the revenue requirement calculated by Mulkern in her direct and supplemental testimony. Aberle stated the cost allocations in the study are based on cost causation with direct assignments made where possible, with remaining costs being allocated primarily on customer-related, demand-related and energy-related factors, depending on the nature of the cost. She said the class cost of service study is consistent with studies MDU has performed in the past. She stated her proposed rates are intended to recover additional revenues in the amount of $5,053,756 per annum, as proposed in the Company's amended application. She testified the results of the class cost of service study indicated that the classes are providing returns on the investment necessary to provide service to each of the rate classes. However, every rate schedule is producing a pro forma return below the overall rate of return. MDU is proposing to increase each rate class in an amount necessary to bring each of these classes' revenue responsibility up to the overall rate of return, with the

exception of the private lighting class, which the Company proposes not to change. MDU proposes to allocate the $15,264 decrease in revenues which would otherwise accrue to this class to all other classes. (Tr., pp. 324-325; MDU Exhibit No. 118, pp. 4-10.)

61. Aberle further stated that, in addition to the rate of return by class, the embedded cost of service study (MDU Exhibit No. No. 130) provided the cost for customer demand and energy-related costs for all classes. She stated the increase in the customer component proposed in this case moves rates toward or to embedded costs as directed by the Commission in the last rate case proceeding. Demand charges for service under the Small General and Large General Service schedules are being adjusted to reflect movement towards recovery of costs as identified in the class cost of service study. The energy rate for each schedule reflects the residual of the revenues required to be collected from each rate schedule after deducting the revenues proposed to be collected from base rates and demand charges. She stated MDU has not proposed any change in rate classes or rate designs in this case. Aberle stated that although the Company filed an inverted block residential rate design as directed by the Commission in its last rate case, the Company prefers to maintain its current rate structure of a monthly base rate and a flat energy charge. However, she stated she would not be averse to implementing an inverted block rate design provided the base rate is set at a minimum level of $25.00 per month. She stated that, unless the Commission adopts the Company's proposed revenue increase proposal, the Company will have to run its cost of service model and its rate design proposals again to determine the appropriate rates for each rate schedule. (Tr., pp. 325-326, 777; MDU Exhibit No. 118, pp. 11-17.)

62. Aberle's direct testimony and exhibits addressed the Company's Irrigation Service – Rate 25, proposal. She stated the rate design retains a base rate and time differentiated demand charge as adopted in the last rate case. The Company is proposing to recover the revenue increase allocated to this rate class by increasing the base rate from $25.00 to $50.00 per month; with no change in the on-peak demand charge of $9.50 per kW or the off-peak demand charge of $3.00 per kW. The remainder of the increase would be recovered through the energy charge. MDU proposed to continue the current peak period of Noon to 8:00 p.m.. (MDU Exhibit No. 118, pp. 15-16.) On cross-examination, Aberle stated that Irrigators who operate on a 24 hour/seven day schedule contribute to the peak because they are poor load factor customers who typically operate four to five months a year. She also discussed the effects of having a shorter peak demand period, stating a shorter peak period would only move the peak to the next hour. She noted the majority of irrigator kWh were billed off peak with approximately 54% of the kWs billed off peak and 46% of the kWs billed on peak. She discussed the demand charge for the Irrigation customers, how it works, and the Company's efforts to work with customers to establish an alternative to the mandatory time-of-day schedule to help customers move off peak. She also described the Company's alternative irrigation rate proposal that she offered in her rebuttal testimony (MDU Exhibit No. 140), which included an optional time-of-day irrigation schedule that would provide an incentive to irrigation customers to move load off-peak, in addition to the standard schedule that includes a non-time differentiated flat demand charge. The standard irrigation rate would include a demand charge of $6.25 for the monthly peak demand regardless of the time the peak demand is established. The optional time-of-day schedule would include the current on-peak charge of $9.50 per kW and the off-peak charge of $3.00 per kW. She assured the Commission that an irrigation customer taking service during the on-peak period

and off-peak period and would not pay a rate of $12.50 per kW but would be billed for each period separately at the applicable $9.50 or $3.00 per kW rate. (Tr., pp. 329, 354, 360, 362-365, 770; MDU Exhibit No. 140, p. 4.) However, an irrigator taking energy during both on-peak and off-peak hours would pay both demand charges, or a total of $12.50 per kW for all hours during the month. (Tr., pp. 385-387.)

63. Aberle also addressed MDU's inclusion in its revenue requirement of approximately $55,000 a year for kVar penalties. Aberle stated the Company believes that a $2.50 per kVar penalty [i] provides an incentive to customers to make a change to their equipment to avoid supplying kVars to the system; [ii] is sufficient to cover the identified potential impacts to the system; and [iii] will provide a revenue stream to cover capacitors and the losses and the other costs associated with kVars being introduced into the system. (Tr., pp. 345-347, 374.)

64. In her rebuttal testimony, Aberle offered an alternative to Zamora's recommendation to use separate demand and energy rates for purchased power and fuel recovered under a tracking mechanism in the PSCA. MDU Exhibit No. No. 141 illustrated her alternative proposal that the demand costs associated with the PSCA be moved to the cost of service component of each rate with only the prospective changes in demand under the contract being billed through an energy charge in the PSCA. Aberle suggested the demand component included in the purchased power agreement is relatively stable; and therefore, prospective changes in demand-related costs under the PSCA mechanism should be minimal. (Tr., pp. 778-783; MDU Exhibit No. 140, pp. 4-5.)

65. Aberle's rebuttal testimony addressed certain rate design-related proposals made by OCA witness Zamora. (MDU Exhibit No. 140.) She discussed Zamora's proposal to introduce a $4.00 per kW charge for the first ten kW billed under the Small General Service Rate 20, Secondary Service, and a $4.50 per kW for the first ten kW billed under Small General Service, Primary Rate 20, schedule. She stated these changes would result in a significant change to a large group of very small use customers taking service under Small General Service Rate 20. The current rate design for the Rate 20 Class provides the first ten kW at no charge with a demand charge being imposed on all kW over ten kW. She stated OCA's proposal would require the purchase and installation of approximately 17,000 demand meters at a cost of approximately $484,500. She recommended the current rate structure be maintained. (Tr., p. 764, MDU Exhibit No. 140, p. 3.)

Summary of OCA's Evidence

66. Ms. Kimber Wichmann, Rate Analyst for the OCA, provided a summary of her prefiled direct testimony, including attached supporting exhibits, which addressed OCA's position on the appropriate ROE, cost of debt, and capital structure that should be used in the computation of MDU's overall rate of return. (OCA Exhibits 201-208.) Wichmann testified her analyses supported a ROE for MDU's Wyoming electric utility operations of 10.4%, resulting in an overall rate of return for the Company of 8.45%. In performing her analyses, she identified a group of twenty-two proxy companies from publicly available financial data which were comparable to MDU's regulated electric utility operations. She stated the filters used in

selecting her comparable companies were that they should have [i] a Baa rating as MDU's issuer rating was Baa1, [ii] at least 70% of revenues from regulated electric operations, and [iii] had to pay dividends in 2009. All but one of Gaske's 13 comparable companies were included in her group of comparable companies. Wichmann stated she utilized a constant growth rate DCF model, a non-constant growth DCF model and a capital asset pricing model (CAPM) in conducting her ROE analyses. She stated the two DCF models provide an estimate of cost of equity capital by examining expected dividends and market prices, but the non-constant growth DCF analysis provides a more realistic estimate of future growth. She stated that she used the CAPM not as a primary model but as an objective measure of risk for regulated electric utilities with the same investment as MDU, in comparison to other securities available to investors. (Tr., pp. 473-475, 483,507-510; OCA Exhibit No. 201, pp. 6-8.)

67. Wichmann testified she and Gaske used similar information sources in performing their respective analyses and in their selection of comparable companies but differed in their application of the information, including their calculation of flotation costs and size adjustments. She stated that, although she supported a flotation cost adjustment, she utilized a conventional flotation cost calculation, which assumes that flotation costs are incurred only when new stock is sold and not when earnings are retained. Under the conventional calculation the flotation adjustment is applied only to the dividend yield of the DCF calculation and not to the growth component. She stated her use of MDU's actual flotation factor of 3.50%, which was lower than an industry average of 3.70% used by Gaske, was appropriate as it was a known factor, and customers should only have to pay the actual cost. As to utilizing a size adjustment as advocated by Gaske, she rejected such an adjustment on the basis that MDU's utility operations do not share the same risk as a small business in a free market, given MDU's status as a regulated monopoly with certain mechanisms such as the PSCA tariff which mitigates the risk of cost recovery. Wichmann identified other areas of disagreement with Gaske's ROE analyses, including his averaging of stock prices in his DCF models, his use of an "unconventional" growth adjustment in his DCF analysis, resulting in an overestimated cost of capital, and the results of his Risk Premium analysis, which fail to support or legitimize the results of his DCF analyses. (Tr., pp. 475-476, 517; OCA Exhibit No. 201, pp. 14-15, 31-34.)

68. Wichmann concluded that her ROE analyses supported a range of reasonableness of 9.05% to 10.93%, with a midpoint of 9.9%. After considering the macroeconomic environment, financial and business risks, growth forecasts and MDU's ability to recover many of its costs through regulatory and tariff provisions she recommended a conservative ROE of 10.4% as providing a reasonable balancing of shareholder's interests with the customer's interests, although she acknowledged that any ROE number falling within her range would be supported by her analysis. Using the Company's pro forma capital structure for 2009, its calculated costs of long-term debt (6.79%), short-term debt (3.77%), preferred stock (4.59%), and OCA's recommended cost of common equity (10.4%), Wichmann recommended an overall rate of return of 8.45%:

Component	Percentage	Cost	Weighted cost
long-term debt	44.959%	6.79%	3.05%
average short-term debt	2.771%	3.77%	0.104%
preferred stock	2.5%	4.59%	0.115%

common equity	49.77%	10.4%	5.18%
TOTAL	100.00%		8.45%

(Tr., pp. 475-477, 521-522; OCA Exhibit No. 201, pp. 23-29, 36; OCA Exhibit No. 208.)

69. Ms. Denise Kay Parrish, OCA's Deputy Administrator, provided a summary of her prefiled direct testimony, including attached supporting exhibits (OCA Exhibits 216-218), in support of OCA's proposal to levelize the cost of the return on MDU's 25% ownership interest in the Wygen III generation Plant over the expected depreciable life of the Plant. Parrish stated the concept behind her levelization proposal was to assure that all generations of MDU's Wyoming electric customers benefiting from the Wygen III Plant pay their proportional share of the return MDU is entitled to earn on its share of the Plant. Through this levelization approach, the impact of adding the Wygen III Plant to rate base would lessened during the initial years the rates are in effect. Levelization would address generational inequities existing today under more traditional methods of front-loaded return on new plant placed in rate base, wherein early generation customers benefiting from the plant pay more return than later generation customers. She stated the total value that MDU would earn over the depreciable life of the Plant is summed; with the total value being divided by the expected Plant life to arrive at an equal dollar amount of return to be recovered from customers during each year of the Plant's operating life. She stated her proposal in addition to not disadvantaging generations of customers is also intended to not disadvantage investors over the life of the Plant by making sure they receive the same amount of return over the life of the Plant by using present value calculations. (Tr., pp. 622-623; OCA Exhibit No. 216, pp. 3-4, 8.)

70. Parrish described the calculation of her levelization proposal (OCA Exhibits 217 and 218), stating she developed a rate base for the Plant based on the 50-year depreciable life that OCA was recommending for Wygen III; but she acknowledged she had not updated her gross Plant numbers as brought up to date by MDU. Based on her calculations, the Company, on behalf of its investors, would have to receive $2.8 million each year for fifty years. Parrish stated that, for purposes of her calculation, she assumed that investors should have the opportunity to receive the same total present value amount that they would receive under current regulatory practices. She testified that, over the 50-year life cycle of the Plant, investors would receive the same dollar value in return that they would receive over the life of the Plant using the more traditional front-loaded method. Her analysis further showed the total amount of return collected by MDU would be approximately $55 million more under her levelized approach as compared to the amount that would need to be collected using a nominal levelized return. She justified this result as being fair because customers will be deferring some of the higher payments to a later time period when the funds they pay will have a lesser value than if they were paying the higher and more traditional cost today. She stated her levelized approach assumes the Company would continue to receive the $2.8 million over the life of the Plant, without modification, even if there were subsequent rate case filings submitted over the course of the 50-year period. (Tr., pp. 624-631; OCA Exhibit No. 216, pp. 8-20.)

71. In Gaske's rebuttal, he argued that her levelization proposal requires future commissions to be bound by the determinations of this Commission regarding this issue over the 50-year period. Parrish responded, acknowledging that, although one commission cannot bind

future commissions, it was her experience that this Commission and prior commissions have been reasonable and have not backed out of prior commitments. She further expressed her disagreement with Gaske's argument that recording the deferral as a regulatory asset would only be acceptable if MDU's customers entered into a 50-year contract to ensure the Company's recovery of its Wygen III investment. Parrish testified that, although her levelization approach would affect cash flow streams for the Company differently than more traditional approaches, because levelization would result in less cash being collected during the earlier years with more cash becoming available in later years, she believed OCA's approach did not violate the standards set out in the *Hope* and *Bluefield* cases, as was argued by Gaske, because the levelization proposal provides OCA's recommended overall rate of return of 8.45% over the life of the Plant. She stated the *Hope* and *Bluefield* cases do not require that regulatory commissions provide specific cash flow streams on a specific schedule. Finally, Parrish stated that, although she did not believe OCA's proposal created more risk for MDU, she provided several options for consideration to mitigate the regulatory risk that might be attributed to the adoption of her levelization proposal. (Tr., pp. 631-635, 637; OCA Exhibit No. 216, pp. 21-24.)

72. Parrish expressed OCA's concerns over possible Commission approval of MDU's latest depreciation studies, which were filed very shortly before the commencement of the hearings in this matter, stating that OCA had only a limited opportunity to review the studies and had many unanswered questions, including: [i] the need to review the Company's rationale for significant differences between present and proposed depreciation rates for various accounts; [ii] issues regarding interim retirement rates; and [iii] other aspects of the depreciation studies that require further review. She recommended the depreciation studies be considered in more detail in a separate docket or in the next rate case. Parrish testified it was reasonable to accept MDU's depreciation adjustment as identified in Mulkern's depreciation testimony (MDU Exhibit No. 142, pp. 2-3), which results in decreasing the Company's revenue increase request by $220,358. (Tr., pp. 639-646, 679-680.)

73. Ms. Amy Zamora, Senior Rate Analyst for the OCA, provided a summary of her prefiled direct testimony, including attached supporting exhibits. (OCA Exhibits 209-215.) Zamora's testimony provided background for the Company's application, including its entry into a new all requirements purchased power contract with Black Hills Power in 2006, which provided MDU with the option, which it exercised, to purchase 25% of Wygen III. She stated MDU will be obligated to pay 25% of the investment cost of the Plant, O&M costs, the costs associated with 25% of the coal needed to fuel the Plant, and certain administrative expenses to Black Hills Power as the Plant operator. Zamora also addressed her review of the Company's revenue requirement, the class cost of service study and rate design, which were incorporated in the OCA revenue requirement recommendation, proposed rate spread and proposed rate design. Zamora stated she reviewed the per books amounts contained in the Company 2008 test year and the Company's pro forma adjustments, whereupon she made her own adjustments to the Company's results to normalize and annualize the test year numbers to remove prior period expenses, one-time expenses, expenses that did not need to be incurred in providing utility service, and expenses that were not known and measureable. She further stated that she separated her adjustments between non-Wygen III-related expenses and Plant, and only Wygen III-related expenses and Plant. Her separation of Wygen III-related expenses and investment

costs from the rest of the revenue requirement was done to accommodate Parrish's proposed levelized return proposal for the Wygen III Plant. (Tr., p. 528: OCA Exhibit No. 209, pp. 3-6.)

74. OCA Exhibit No. 211 sets forth OCA's non-Wygen III-related adjustments to revenues, purchased power and fuel costs, O&M expenses, depreciation expense, Taxes Other Than Income, deferred income taxes and current income taxes. Zamora's revenue adjustment was comprised of an MDU-provided correction to the pro forma usage and revenue calculations for Large General Service Class Rate 39, which increases pro-forma revenues by $18,726. In all, OCA made six adjustments to O&M expenses, including increasing the purchased power expense by $18,714, to reflect the correction in the Rate 39 usage calculation, and increasing expenses by $6,782,183 to remove the MDU calculated Wygen III-related purchased power and fuel costs, for a net expense increase adjustment of $6,801,897. She stated the changes are included in the Wygen III-related adjustments. An adjustment was made to remove Wygen III-related O&M expenses of $2,681,907, which would be included in the Wygen III adjustments. Zamora made an additional adjustment to remove institutional advertising and industry dues expenses of $2,413 on the basis these expenses need not be incurred in providing service. Zamora supported her adjustment by stating institutional advertising should be shareholder funded. Recovery of these expenses has been denied by the Commission in past cases, and are here precluded from rate recovery under OCA's interpretation of Commission Rule Section 248. OCA proposed to amortize regulatory commission (rate case) expense over a ten year period to reflect the historical length of time between past Company general rate filings, as opposed to the three years proposed by the Company. OCA also proposed an O&M expense reduction of $6,551 to remove MDU's general inflation adjustment for other miscellaneous expense items. Zamora testified that adjusting these other expenses by a blanket percentage, based upon the consumer price index, is not a known and measurable adjustment, and has been disallowed by the Commission in cases involving other utilities. Finally, OCA removed certain one-time expenses occurring in the test period, prior period adjustments, and costs recovered through the Company's Load Management Program resulting, after a correction to OCA's computations, in an O&M expense reduction of $30,994. (Tr., pp. 528-532, 561, 584-585, 589; OCA Exhibit No. 209, pp. 6-8.)

75. Zamora discussed her removal of MDU's calculation of Wygen III-related depreciation expense of $1,744,988, saying it would be offset by inclusion in her Wygen III adjustments. Regarding the Company's filing of its most recent depreciation studies that had the effect of reducing depreciation expense, she stated OCA accepted the adjustment in this case but requested additional time to allow a more thorough review of the studies and the proposed depreciation rates in the context of a future proceeding. Regarding her adjustments for Taxes Other Than Income Taxes, she annualized franchise and gross revenue taxes by applying OCA's adjusted revenues to the appropriate tax factors, and removed MDU's pro forma ad valorem taxes related to Wygen III stating they would be added in later as part of her Wygen III adjustments, for a net decrease of $100,327. Zamora also proposed an annualized adjustment to deferred income taxes for all other plant by using a full year of book depreciation for all assets regardless of when they went into service, as opposed to the Company's use of one-half year's depreciation. She supported this adjustment by stating use of one-half year's depreciation is inappropriate as it would not reflect a normal year of depreciation for ratemaking purposes, and it does not match the full year of depreciation used for depreciation expense. This adjustment

also recognizes MDU's applying of the IRS-authorized 50% bonus depreciation rate and the accumulated depreciation rate toward plant additions placed in service in 2009 or for expenditures incurred in 2009. She removed the calculated deferred income taxes for Wygen III which resulted in a decrease of $817,322, for a net reduction for these two adjustments of $822,626. She proposed an interest synchronization adjustment of $1,534 to synchronize interest expense with OCA's calculated rate base, excluding Wygen III. She also removed interest expense for the Wygen III rate base. The net effect of these two adjustments amounted to a $1,947,215 decrease in interest expense. Based upon the above-described adjustments, as corrected, MDU's adjusted operating income is reduced by $2,103,062. (Tr., pp. 532-534; OCA Exhibit No. 209, pp. 10-12.)

76. Zamora also proposed adjustments to the Company's rate base (OCA Exhibit No. 213) which included the removal of Wygen III costs related to the investment, accumulated depreciation and accumulated deferred income taxes and updates to accumulated deferred income taxes for all other investments, resulting in a total revised rate base, without Wygen III, of $18,902,960. Zamora stated that with OCA's revised adjusted test year return of approximately $1.6 million, the resulting rate of return without Wygen III is 8.587%, which exceeds OCA's recommended overall rate of return of 8.45%, resulting in the need for a revenue decrease. (Tr., pp. 538-539.)

77. Zamora testified to OCA's adjustments related to and including Wygen III, for purchased power and fuel, O&M expenses, Taxes Other Than Income and deferred income taxes. Regarding purchased power and fuel costs, she stated OCA's adjustment for decreases in energy capacity and transmission costs were the same as MDU's adjustment, but she adjusted fuel costs by $1,902,225 based on the gross tonnage of coal estimated by Black Hills Power to be used in Wygen III. She stated she used a more current estimate of gross tonnage provided by Black Hills Power in its currently pending rate case, which resulted in a net adjustment decrease of approximately $6.9 million dollars in purchased power and fuel expenses. In addition, she made adjustments to Wygen III-related O&M expenses, and to Wygen III-related depreciation expense. Zamora stated her gross Plant cost as reflected in her prefiled testimony was $61.7 million, but acknowledged that MDU had provided an updated gross Plant cost on rebuttal, which she wished to verify prior to accepting it. She also adopted a depreciation expense adjustment to reflect a 50 year Plant life, testifying that it is appropriate, reasonable and consistent with depreciable lives used by other utilities for similar generating plants. Zamora made additional adjustments to Wygen III-related ad valorem taxes to reflect the most current 2009 mill levy, and the use of a full year of depreciation for deferred income taxes. She stated the tax depreciation for Wygen III had been adjusted to reflect the use of the special 50% bonus depreciation rate. She stated that she had included certain costs that were not incurred in 2009 in calculating tax depreciation which might require further revision. (Tr., pp. 539-541, 557, 596; OCA Exhibit No. 209, pp. 12.)

78. Zamora testified that her calculation for the Wygen III only portion of the revenue requirement is based on OCA's levelized return at present value for Wygen III of $2,825,952. The decrease in expenses of $1,871,213 per OCA's adjustments, when subtracted from the $2,825,952 recommended return for Wygen III results in the need for additional revenue of $954,739. Adjusting this amount by the federal income tax factor results in the need for

additional revenues for Wygen III of $1,485,693. OCA's total recommended additional revenue requirement, taking into consideration OCA's recommended decrease in revenues without Wygen III of approximately $40,000, when combined with the revenue requirement for Wygen III, results in a total revenue increase of approximately $1.45 million or 7.852%. (Tr., p. 542; OCA Exhibit No. 209, p. 18.)

79. Zamora provided testimony regarding MDU's class cost of service study, stating she found it to be reasonable, with the methodologies and allocations being comparable to other studies that have been accepted by the Commission. She utilized MDU's cost of service study in performing two model runs for each piece of her revenue requirement and then added the results of the two runs for the revenue requirement without Wygen III and with the Wygen III-only revenue requirement to determine total costs to serve each customer class. (OCA Exhibit No. 214.) Zamora stated that after allocation of OCA's proposed additional revenue increase, each rate class will be providing the same percentage increase on each piece of the revenue requirement, i.e., non-Wygen III and Wygen III-only, with the effective rate of return for each class being slightly different and ranging from 5.857% to 7.564%. In doing so, OCA moved each class toward (but not to) recovery of its full cost of service-based revenue responsibility, with all classes receiving an increase except the Private Lighting Class which is currently exceeding its cost of service, and therefore will see a 36.9% decrease. (Tr., pp. 545-546: OCA Exhibit No. 209, pp. 19-23.)

80. Zamora addressed OCA's proposed rate designs for the various customer classes, stating she utilized the Company's class cost of service model in developing her rate design recommendations, the results of which are set out in OCA Exhibit No. 215. She described her rate design proposals for the various customer classes. (OCA Exhibit No. 209, pp. 26-30.) She proposed an inverted block energy charge for Schedule 10, Residential Class, with a monthly customer charge of $25.50. OCA's initial proposed rate design for Schedule 20, Small General Service, included demand rates for all customers in the class; but she discovered that customers in the class using less than 10 kW did not have demand meters, and stated her rate design would not work for the entire class because demand could not be measured for the entire class. Therefore, she withdrew her recommendation of a demand charge for Rate 20 customers using less than 10 kW. Zamora stated the Schedule 25, Irrigation Class, is the only class whose rate components are not recovering their respective full costs. She testified the cost of service study supports a monthly charge of $105.64; but, to avoid rate shock, she proposed a monthly charge of only $50.00, which is about twice the current monthly charge. In addition, OCA is proposing a reduction in the on-peak demand rate of $9.50 per kW to $8.30 per kW, with the off-peak rate remaining at $3.00, which will bring this rate element to cost of service. Regarding Aberle's proposal on rebuttal of offering a time-of-use rate and a non-time-of-use rate to irrigation customers, Zamora deemed it a reasonable alternative. She acknowledged that, [i] if the revenue increase ultimately approved differs from that proposed by OCA, the rate design will have to be revised, and [ii] if the amount of the increase is significant, it might impact her proposal to move to cost based rates. (Tr., pp. 547-549, 552-553, 556 & 611; OCA Exhibit No. 209, pp. 26, 29-30.)

81. Zamora described OCA's proposed revisions to the Company's current PSCA to reflect its change in status from a purchaser of all its power requirements to, in part, a self-

generator. It is OCA's position that as a self-generator of a portion of its power requirements, the provisions of Commission Rule Sections 249 and 250, which currently apply to MDU, will no longer be applicable. She testified that these rule provisions have not been interpreted in a manner which would allow a self-generator to accumulate its production costs and pass them on to customers. Recovery of these production costs is typically addressed in computing base rates. Her proposed tariff language to revise the PSCA is similar to the language used by Cheyenne Light, Fuel and Power Company, which she recommended as an appropriate starting point for PSCA revision. OCA proposed a deadband of $290,000, based on a proportion of kWh sales, to assure that some portion of the system power cost changes are borne by the Company's shareholders rather than placing all the risk and reward of changing system power costs on ratepayers. In addition, ratepayers would only receive 95% of the cost changes that fall outside the deadband. Zamora testified this approach will incent the Company to make operational decisions for the benefit of customers. She also recommended further tariff language changes to the PSCA. She advocated changing the term "Base Rate" in each rate schedule to "Basic Service Charge" to reduce confusion. She noted the "Energy Charge" reference in the rates in the tariffs is actually comprised of two components, and argued they should be separately identified by the base purchased power and fuel cost rate component and the energy rate component, to arrive at the "Energy Charge" in an effort to provide more transparency in demonstrating how the energy charge in the PSCA is calculated. (Tr., p. 550; OCA Exhibit No. 209, pp. 32-34, 37-38.)

Summary of Parties' Testimony on Stipulation

82. The Commission reopened the record at its hearing of March 22, 2010, to receive into the record the *Stipulation* (MDU/OCA Joint Exhibits No. 1 and 2) and the parties' testimony and exhibits in support of the *Stipulation*. Mr. Bruce S. Asay, MDU counsel, offered certain late-filed exhibits in addition to the exhibits to the *Stipulation*. The offered late-filed exhibits included: [i] Exhibit No. 157, an explanation of the Company's AFUDC calculations; [ii] Exhibit No. 158, a document identified as the shared assets administrative fee and ground lease; and [iii] Exhibit No. 159, the detailed class cost of service study and work papers. Provided in support of the *Stipulation* were Goodin's affidavit (MDU Exhibit No. 60); Mulkern prefiled testimony (MDU Exhibit No. 161) and Aberle's prefiled testimony and exhibits (MDU Exhibit No. 162).

83. Mulkern summarized her testimony, stating the *Stipulation* represents the parties' efforts to arrive at negotiated agreements regarding various adjustments initially advocated in the parties' respective direct and rebuttal cases. She stated the Company believed the *Stipulation* is in the public interest and should be approved. Mulkern summarized the various terms and conditions of the *Stipulation* including an identification of the various stipulated adjustments, which result in a stipulated increase in MDU's revenue requirement of $3,253,726 per annum. The *Stipulation* provides, *inter alia,* for the implementation of the stipulated revenue increase over a three-year phase-in period. Mulkern testified the phase-in approach addresses the concerns expressed by many MDU customers at the Sheridan public comment hearing that the immediate implementation of the 25% revenue increase was excessive, caused rate shock, and precluded customers' ability to budget for such a large increase. In the phase-in plan, a Year 1, increase of $1.8 million or 8.9% would be implemented on May 1, 2010. The remaining $1.4 million or 6.6% would be implemented in Year 2 on May 1, 2011, and would also include a separate surcharge of $0.0029 per kWh which would be amortized over a two-year period or

until the remaining deferred amount, including interest, is amortized to zero. She stated the interest component is based on the overall stipulated return of 8.68%, explaining the 8.68% was not really an interest rate but rather the rate of return or a carrying charge. Adding together the deferred amount and the surcharge, the Year 2 total increase would be $2,261,726 or 10.3%. She acknowledged the overall increase of 10.3% in Year 2 was on top of the 8.9% increase in Year 1, essentially resulting in an increase of 20.1%. She stated customers will experience an increase in the first and second year; but there would be no change in rates in the third year. In the fourth year, customers would see a decrease in rates due to the elimination of the surcharge. She agreed customers would still be paying the 20.1% increase in Year 3 because of the amortization of the amount deferred in the first year. She also acknowledged the stipulated increase would be 16.1% if it were implemented in its entirety this year rather than being phased in as proposed in the *Stipulation*. (Transcript of March 22, 2010, Stipulation Comment Hearing, hereinafter Stipulation Comment Tr., pp. 16-17, 19, 36-39, 41-44; MDU/OCA Joint Exhibit No. 1, pp. 5-6.)

84. Mulkern stated that to address irrigation customers' concerns, MDU will bifurcate the Rate 25 irrigation rate into two rate schedules; [i] the optional time-of-day irrigation rate; or, if preferable, [ii] a more traditional non-time differentiated rate with a flat demand and energy charge. The optional time-of-day tariff will utilize an on-peak period of 3:00 p.m. to 7:00 p.m. She stated the *Stipulation* also includes a revised PSCA Rate 50 which includes a sharing of costs symmetrically above and below the base cost of power supply of 90% to the customer and 10% to the Company. She also stated the parties had agreed to a negotiated 45-year depreciated life for Wygen III. (Stipulation Comment Tr., pp. 17, 24, 29.)

85. Ms. Tamie Aberle provided a summary of her prefiled testimony and exhibits in support of the *Stipulation*. (MDU Exhibit No. 162) She testified that the stipulated increase of $3,253,726 was allocated to each of the rate classes based on the results of the embedded class cost of service study. (Exhibit No. TAA-1 to MDU Exhibit No. 162.) Regarding the phase-in of the rate increase, Aberle stated the Years 1 and 2 increases were allocated to each rate class based on the revenue requirement for each particular class as derived from the embedded class cost of service study. The surcharge needed to collect the deferred portion of the revenue increase was spread to all customer classes based on energy usage. She stated the revenue increase was allocated so each class would produce the overall rate of return of 8.68%. Going forward with those revenues, she agreed, would produce a rate of return for all classes of 8.68%. (Exhibit No. TAA-2 to MDU Exhibit No. 162.) She acknowledged that, depending on the customer's usage, the surcharge could affect a Rate 39 large service customer differently than a residential customer. She discussed the $0.00290 per kWh surcharge, stating under the proposed *Stipulation*, the residential class would experience an increase of approximately $3.95 per month in Year 1 and $7.70 per month in Year 2. (Stipulation Comment Tr., pp. 61-62, 69-71, 82-88.)

86. Aberle stated the *Stipulation* will result in changes to Small General Service Rate 20 in that it had been split into separate schedules for demand and non-demand metered customers. She discussed the irrigation service rate, stating the schedule was bifurcated into Rate 25, non-time differentiated rate, and Rate 26, for customers who choose the option of using time-differentiated service. Aberle testified that irrigation customers can choose a new rate schedule at the beginning of their irrigation season but prior to any usage for that season. Under the *Stipulation*, the irrigation tariff provides that customers may choose a rate schedule through

May of 2010. Aberle stated the Company does not want irrigation customers to change rate schedules during the season because of the additional administrative burden and the need to reprogram meters. She said MDU would probably inform its irrigation customers of this change and the options available to them by sending a letter to its customers. Under the *Stipulation*, the negotiated time-of-use irrigation peak period is from 3:00 p.m. to 7:00 p.m. Aberle acknowledged the evidence presented in this case demonstrated the peak periods fall between 4:00 p.m. and 6:00 p.m. with the majority occurring at 5:00 p.m. (MDU Exhibit No. 122.) She also discussed costs to serve irrigation customers and how the demand charge was calculated. The *Stipulation* proposes a demand charge of $6.25 per kW for non-time-of-use irrigators. (Stipulation Comment Tr., pp. 62-69, 75-77, 79-82, 89-97.)

87. Zamora provided a summary of her prefiled testimony and exhibits in support of the *Stipulation*. (OCA Exhibits No. 219, 220, and 221.) Zamora's testimony explained how the *Stipulation* resolved the issues identified in OCA's direct case regarding revenue requirement, rate design and tariff issues, and why she believed approval of the *Stipulation* was in the public interest. She stated [i] the parties had stipulated to an ROE of 10.9%, resulting in an overall rate of return of 8.68%; and [ii] the Company adopted OCA's adjustments, or agreed to revise OCA's adjustments with updated information. The *Stipulation* further provides for an increase in revenues of $3,253,726 per annum to be effective May 1, 2010, to be phased-in over a three year period (an explanation of the phase-in increases is found in the *Stipulation* at ¶¶ 16-20). She stated the phase-in approach was intended to address the concern expressed by MDU's customers at the Sheridan public comment hearing over the significant size of the proposed rate increase and would give customers an opportunity during the first year of implementation to plan and budget for the additional increase to occur in the second year. She also addressed the proposed interest on the deferred amount of 8.68%, which was based on the overall stipulated rate of return. She found them appropriate and reasonable.

88. Zamora stated other significant issues in the *Stipulation* included, but were not limited to, a stipulated depreciation life of forty-five years for Wygen III, and rate design issues for residential, small general service and irrigation customers. She also testified that the *Stipulation* provides for a revised Rate 50 Schedule applicable to the PSCA that provides for a deadband or sharing mechanism based on a 90/10 ratio, wherein MDU would recover 90% of its purchased power and fuel costs above the base rate costs and will return 90% of purchased power and fuel costs below the base rate costs. (Tr., pp. 103-105, 115-116, 137; OCA Exhibit No. 219, pp. 3-4, 7.)

Findings of Fact: Public Comments

89. The Commission heard numerous comments from MDU ratepayers at the February 10, 2010, hearing in Sheridan. City and county officials and representatives from the Sheridan County School District and Board of Directors, Sheridan Memorial Hospital, Sheridan County Public Library, AARP, Powder River Basin Resource Council and the Sheridan County Stock Growers expressed concerns that the amount of the increase would negatively impact their respective budgets and would result in the loss of jobs and programs. Numerous MDU residential customers opposed the proposed rate increase because of current economic conditions, inflation and the financial burden it would place on ratepayers. Ratepayers generally

questioned [i] the magnitude of the proposed increase, [ii] the effect it will have on their electricity bills, [iii] the prudency of MDU's investment in Wygen III, [iv] the proposed ROE, and [v] the depreciable life of the Plant.

90. Mr. Bill Bensel, Chairman of the Wyoming Water Development Commission and an MDU irrigation and residential customer, provided comments generally opposing the irrigation demand charge and rate structure changes for the Irrigation class, stating the peak hours needed to be adjusted to allow irrigators to irrigate their fields consistent with state water laws. Bensel also discussed the prudency of MDU's investment in Wygen III and offered several alternatives for MDU and the Commission to consider when seeking to meet future electricity demands. He discussed the difficulty irrigators will face when trying to shut down their systems to avoid watering during peak times, and he questioned whether the proposed increases will cause irrigators to discontinue doing business because they no longer can afford to irrigate their lands. Bensel expressed concern that MDU's proposed peak hours were not compatible with state water laws or the way irrigation is managed and used and could result in a loss of the irrigators' water and water rights. He stated that the demand rate option of a $6.25 per kW demand charge would not be a workable alternative. Bensel also explained that flood irrigation has become less common in the Sheridan area, so most irrigators pump constantly. (Tr., pp. 63-67, 438-456.)

91. The Commission wishes to express its gratitude to the Sheridan ratepayers for their participation in the public comment hearing. The Commission was impressed with the high level of rate payer participation and the thoughtful quality of their comments and questions. The public raised a substantial number of issues which are worthy of comment; and we will address these issues to help MDU's customers better understand the regulatory process and the decisions of this Commission. Some of the questions posed by MDU's customers and the answers are as follows:

a. Question. When and why did MDU decide to purchase a 25% share in Wygen III Plant? Why did MDU not consider wind as an alternative? Has MDU lost the flexibility of competitive bidding for supply contracts?

Answer. MDU had an option which expired December 31, 2008, to purchase a portion of the Wygen III facility. Because the Company was faced with the expiration of favorable long-term supply contracts in 2016, it was concerned that long-term supply and demand trends would make Sheridan ratepayers vulnerable to wholesale market volatility, including unstable prices and sharp price increases. Its analysis showed that the best option for protecting Sheridan ratepayers was to purchase a share in Wygen III. Black Hills had a proven record of being able to construct similar plants on time and on or under budget.

MDU did not specifically consider wind as an alternative. However, the Commission is aware that wind is generally more expensive. Although costs are coming down as the technology matures, wind is somewhat expensive; and it is, by its nature, an intermittent resource. Complete reliance on wind power poses considerable service and economic risks to a utility with a relatively small service population. Wind integration cost is discussed in a Black and Veatch paper found under the Hot Topics section of the Commission's web site at

http://psc.state.wy.us. Interested persons should also review the Western Wind and Solar Integration Study prepared for the National Renewable Energy Laboratory in Golden, Colorado. It may also be found under Hot Topics/Wind Integration on the PSC's web site.

b. Question. Has the economic downturn lowered the cost of equity capital?

Answer. In general, this appears to be the case. However, the cost of equity capital for a public utility must be considered in comparison to similar companies. Both parties submitted evidence on this question, and the Commission decided on a return on equity capital less than that originally proposed by either party. However, the Commission is not free to ignore established legal standards (found in statute, Wyoming and federal Supreme Court cases) which address the type of evidence the Commission must consider in reaching conclusions on capital costs.

c. Question. Could the Commission require MDU to rely entirely on debt, with no equity?

Answer. When a utility's capital structure is out of balance, i.e., when it relies too heavily on debt, the Commission may order the use of a hypothetical capital structure for ratemaking purposes and has done so in the past. As a utility approaches a 100% debt capital structure, it becomes much riskier for itself and bondholders. If all of its financing is done with fixed obligations (bonds), it must pay for all of its financing on a regular basis in fixed amounts. This increases the chance of default and bondholders would rightly demand higher and higher returns on their investments, to the point at which small companies might become so risky that they could be denied access to capital markets. Similarly, a 100% common equity capital structure would lessen the ability of a utility to raise needed money through issuance of more common stock. Potential stockholders would be buying a heavily diluted portion of the company. Issuance costs would rise and perhaps stock would remain unsold. A balanced capital structure gives the utility the ability to access capital markets on generally reasonable terms. Given our statutory charge under Wyoming law that rates may not be unfair, discriminatory, unjust, unreasonable or unremunerative, ordering reliance on 100% debt would be contrary to law.

d. Question. Could the Commission require 60-year depreciation on the Plant?

Answer. The Commission theoretically could, but doing so would not be supported by the evidence of record in this case. Such action outside of the record would be arbitrary on its face under the Wyoming Administrative Procedure Act and subject to being overturned on appeal.

e. Question. Could the Commission authorize a return on equity in the mid-single digits?

Answer. It could do so if the evidence of record supported it. However, such a decision would not be supported by the evidence in this case and or requirements of law (including the United States Supreme Court cases discussed below). As in ¶ 93d above, if the Commission were to act arbitrarily, its decision could be set aside after judicial review.

f. Question. Is the return on equity based on good comparables?

Answer. As the case is decided, yes.

g. Question. Can the irrigation rate be adjusted?

Answer. The irrigation rate has been adjusted, consistent with the principle that each class of service must bear its own costs. On the last day of the hearing, devoted principally to the *Stipulation*, the Commission reviewed details of MDU's cost of service study as it relates to irrigation service. The Commission is satisfied with the results of the cost of service study and notes that the new optional irrigation tariff reduces the daily peak hours from an eight-hour window to a two-hour window when the actual MDU system peaks occur. The Commission also notes that OCA did not question MDU's cost of service study.

h. Question. Has MDU addressed its own cost structure?

Answer. That issue was more directly addressed in last year's rate case. Until 2008, MDU's management had successfully operated under a rate structure which had been in place since 1993. The Commission believes MDU is competently managed, and there has been no evidence offered to show that MDU has incurred excessive or imprudent costs. The need for this rate case rests principally on the purchase of a 25% share of Wygen III.

i. Question. Has MDU accounted for the savings it will realize by not having to purchase all of its power?

Answer. Yes. The purchased power costs are decreased in this case to account for the power generated by the Wygen III Plant.

j. Question. Why are we guaranteeing MDU a return on equity when the healthiest companies in the nation are losing money and private citizens' investments and businesses do not have guaranteed returns?

Answer. The Commission does not guarantee MDU a return on its equity. It only gives MDU an opportunity to earn a return on equity, and in doing so, sets a maximum allowable return. Utilities commonly fail to earn the authorized rate of return. We have to determine a fair rate of return as noted above. Also see the *Hope* and *Bluefield* cases discussed below. They are the standard for utility regulators throughout the United States.

k. Question. Can MDU do better with demand side management?

Answer. The Commission will address this question in another docket, already in progress. The Commission notes that the cost of demand side management measures are typically passed on to ratepayers as a surcharge, which means that benefits of proposed measures must be thoughtfully scrutinized and tested to see whether they provide real value for consumers.

l. Question. Are the ratepayers bearing the risk of MDU's investment in Wygen III?

Answer. There are different forms of risk. However, as we understand the original question, we believe the answer is that ratepayers are not guaranteeing a return to MDU or otherwise limiting MDU's own risks in a manner uncommon for utilities in Wyoming or elsewhere in the United States. In this regard, we note that under Wyoming law, public utilities like MDU are granted exclusive service territories, and so are insulated from competitive risk. Also, it is important to understand that, in areas of the country where utilities are free to compete, lower prices do not always result.

m. Question. How does MDU compare with Rocky Mountain Power, which was reported to be asking for a 3% decrease in its power costs?

Answer. The newspaper accounts were a bit misleading since they addressed only the portion of Rocky Mountain rates which were driven by purchased power and fuel costs. Its overall rates have been rising. Rocky Mountain has advised the Commission that it intends to file rate cases on a yearly basis for the near future.

For the past four years, Rocky Mountain Power normally has had two proceedings a year, one to increase general rates, and one to pass on power costs. In this year's general rate case proceeding, Rocky Mountain Power requested a rate increase of $70 million per annum. Rocky Mountain Power and the parties in those two cases have proposed a combined settlement that would cut this increase in half.

Rocky Mountain Power's plans for the coming ten years call for $10 billion of new investment a substantial portion of which is driven by environmental standards and new transmission to serve its customers. Rate increases every year are likely, in addition to whatever proceedings there may be to adjust power costs. MDU does not have similar plans.

n. Question. Did MDU responsibly forecast its need for the next ten years before it decided to invest in Wygen III?

Answer. Yes.

o. Question. Should MDU have been directed to discuss its investment decision with the customers before it went ahead?

Answer. The Commission considered MDU's decision to become involved with Wygen III in a public hearing for a proposed certificate of public convenience and

necessity. That proceeding, which forecast a rate increase of 17%, drew far less attention than the Company's eventual proposal to increase rates by nearly double that amount. We note that the Stipulation here proposed an increase of 16.1%, and the Commission approved an increase that was even smaller. The Commission is charged with regulating utilities, not managing them. We cannot require the public to pay active attention to a Company decision, even one which may have long term effects; and such discussions would be outside of the record of this case. That is, the Commission could not use such meetings in making its decision here.

Legal Standards Applicable in This Case

92. W.S. § 37-3-101 states:

> All rates shall be just and reasonable, and all unjust and unreasonable rates are prohibited. A rate shall no be considered unjust or unreasonable on the basis that it is innovative in form or in substance, that it takes into consideration competitive marketplace elements or that it provides for incentives to a public utility. * * * The commission may determine that rates for the same service may vary depending on cost, the competitive marketplace, the need for universally available and affordable service, the need for contribution to the joint and common costs of the public utility, volume and other discounts, and other reasonable business practices. * * *

93. The Commission has broad powers to inquire into the facts surrounding the determination of rates. They include W.S. § 37-2-119, which articulates the "used and useful" test and allows wide latitude in the Commission's investigation of rate-related matters. It states, in part:

> In conducting any investigation pursuant to the provisions of this act the commission may investigate, consider and determine such matters as the cost or value, or both, of the property and business of any public utility, used and useful for the convenience of the public, and all matters affecting or influencing such cost or value, the operating statistics for any public utility both as to revenues and expenses and as to the physical features of operation...

94. W.S. § 37-2-120 requires the Commission to afford due process in its cases, stating, in part:

> No order, however, shall be made by the commission which requires the change of any rate or service, facility or service regulation except as otherwise specifically provided, unless or until all parties are afforded an opportunity for a hearing in accordance with the Wyoming Administrative Procedure Act.

95. W.S. § 37-2-121 gives the Commission latitude to determine the actual rates to be charged by a utility, stating, in part:

> If upon hearing and investigation, any rate shall be found by the commission to be inadequate or unremunerative, or to be unjust, or unreasonable, or unjustly discriminatory, or unduly preferential or otherwise in any respect in violation of any provision of this act, the commission may fix and order substituted therefore such rate as it shall determine to be just and reasonable and in compliance with the provisions of this act.

96. W.S. § 37-2-122(a) reinforces the Commission's ability to exercise its sound informed discretion in rate making cases. It states:

> In determining what are just and reasonable rates the commission may take into consideration availability or reliability of service, depreciation of plant, technological obsolescence of equipment, expense of operation, physical and other values of the plant, system, business and properties of the public utility whose rates are under consideration.

97. W.S. § 37-2-122(b) gives similar necessary latitude to the Commission regarding utility services, stating:

> If, upon hearing and investigation, any service or service regulation of any public utility shall be found by the commission to be unjustly discriminatory or unduly preferential, or any service or facility shall be found to be inadequate or unsafe, or any service regulation shall be found to be unjust or unreasonable, or any service, facility or service regulation shall be found otherwise in any respect to be in violation of any provisions of this act, the commission may prescribe and order substituted therefore such service, facility or service regulation, as it shall determine to be adequate and safe, or just and reasonable, as the case may be and otherwise in compliance with the provisions of this act, including any provisions concerning the availability or reliability of service. It shall be the duty of the public utility to comply with and conform to such determination and order of the commission.

98. At W.S. § 16-3-107, the Wyoming Administrative Procedure Act sets parameters for due process in Commission cases, including the giving of reasonable notice. In accord are W.S. §§ 37-2-201, 37-2-202, and 37-3-106. See also, Sections 106 and 115 of the Commission's Rules.

99. Read in pari materia, these statutes articulate the basic mechanism of the public interest standard which the Commission is to follow in its decisions. The public interest must come first in the Commission's decisions, as the Wyoming Supreme Court has stated; and the desires of the utility are secondary to it. *Mountain Fuel Supply Company v. Public Service Comm'n*, 662 P.2d 878 (Wyo. 1983). Construing W.S. § 37-3-101, which requires rates to be reasonable, the Court in *Mountain Fuel, supra*, at 883, commented:

> This court cannot usurp the legislative functions delegated to the PSC in setting appropriate rates, but will defer to the agency discretion so long as the results are fair, reasonable, uniform and not unduly discriminatory.

Later, 662 P.2d at 885, the Court in Mountain Fuel observed:

> We agree that if the end result complies with the 'just and reasonable' standard announced in the statute, the methodology used by the PSC is not a concern of this court, but is a matter encompassed within the prerogatives of the PSC.

100. In accord are *Great Western Sugar Co. v. Wyo. Public Service Comm'n and MDU*, 624 P.2d 1184 (Wyo. 1981); and *Union Tel. Co. v. Public Service Comm'n*, 821 P.2d 550 (Wyo. 1991), wherein the Supreme Court stated, 821 P.2d at 563, that it "...has recognized that discretion is vested in the PSC in establishing rate-making methodology so long as the result reached is reasonable."

101. Consistent with the discretion given to the Commission in examining cases and reaching a just result, there are no precise bases in Wyoming law to guide the Commission in determining a utility's rate of return. Therefore, the Commission must apply its informed

judgment to all of the evidence in the case. In this work, we are guided by the earnings and capital attraction standards of *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U. S. 679 (1923); and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U. S. 391 (1944); accepted in Wyoming in *In re Northern Utilities*, 70 Wyo. 275, 249 P.2d 769 (Wyo. 1952). Taken together, these cases stand for the principle that a public utility is entitled to rates which will permit it a reasonable opportunity to earn a return on its investment properly reflecting the risk of the business and which will reasonably preserve the financial soundness of the company and allow it to raise the capital needed to provide service in the public interest. Having said that, we also acknowledge that the measurement of the required level of return is not a matter of simple mathematics but is a matter requiring judgment and the employment of discretion. The United States Supreme Court, in *Hope, supra*, noted that a "just and reasonable end result" is the desired outcome and that it is the end reached, rather than the method employed in achieving it, that should control.

102. Under Section 119, Settlements, of the Commission's Rules, "...informal disposition may be made of any hearing by stipulation, agreed settlement, consent order or default upon approval of the Commission."

103. In *Willadsen v. Christopulos*, 1987 WY 5, 731 P.2d 1181, (Wyo. 1987) the Wyoming Supreme Court discussed the standard of proof to be used in Wyoming administrative hearings. Construing Wyoming Statutes (W.S. §§ 41-3-911(b) and 41-3-911(c)), neither of which names the standard to be applied in matters coming before the State Board of Control, the Supreme Court stated, 1987 WY 5 at ¶13, with regard to W.S. § 41-3-911(c):

> Under that statutory section and the applicable provisions of the Wyoming Administrative Procedure Act, the standard applicable to an adjudicatory hearing before the Board of Control, unless otherwise stated, is the "preponderance of the evidence" standard customarily used in civil cases. Amerada Hess Pipeline Corporation v. Alaska Public Utilities Commission, Alaska, 711 P.2d 1170, 1179 n. 14 (1986); Intermountain Health Care, Inc. v. Board of County Commissioners of Blaine County, Idaho, 107 Idaho 248, 688 P.2d 260, 263 (1984), quoting E. Cleary, McCormick on Evidence § 357 (3d ed. 1984).

Later, the Court emphasized the necessity of applying this standard, 1987 WY 5 at ¶14, saying:

> Because the Board of Control failed to apply the preponderance of the evidence standard and instead applied the substantial evidence test applicable to appellate review of an agency decision, we find that petitioners were denied due process.

Although one of the statutes on which we rely in this case, W.S. § 37-1-121, specifies the substantial evidence standard, the other sections do not. We must therefore agree with the Court in *Willadsen*, that the correct standard to apply to this case is the higher preponderance of the evidence standard. We would be remiss in even colorably denying due process in this case and will not do so.

Additional Findings of Fact

104. Many of the particular facts necessary to the decision of this case have been stated above and will not be restated here.

105. MDU filed its initial general rate case filing seeking additional revenue relief in the amount of $6,198,501 per annum (30.7% overall increase). The Company subsequently filed its supplemental or amended application reducing the amount of its requested revenue increase to $5,053,756 per annum (25.1% overall increase) to reflect its accelerated/bonus depreciation deduction adjustment related to Wygen III, as provided for under federal law for certain qualifying property additions. The Company subsequently filed its updated electric division Depreciation Study and Common Plant Depreciation Study in which it proposed certain revised depreciation rates; the net effect of which is a further decrease in the Company's revenue request to $4,833,545 per annum. The OCA offered its testimony through expert witnesses supporting its initial proposed revenue increase of $1,430,794 per annum (7.773% overall). (OCA Exhibit No. 210.)

106. At the conclusion of the contested portion of the public hearing in which MDU and OCA presented their positions on an appropriate revenue increase, they advised the Commission they were in the process of negotiating a settlement which culminated in the filing of the *Stipulation*. An additional public hearing was held in which Company and OCA witnesses provided testimony in support of the *Stipulation* which provided for a negotiated revenue increase of $3,253,726 per annum based upon a 10.9% return on equity, which when applied to the Company's proposed capital structure results in an 8.68% overall return on rate base. Generally, the *Stipulation* provided for a three year phase-in of the revenue increase including interest on the amount of the increase deferred in the first year of the phase-in. Other major provisions in the *Stipulation* included depreciation expense and other depreciation-related calculations based on a negotiated 45 year Wygen III depreciation life, the offering of Rate 25 and Rate 26 irrigation schedules, the filing of a rate case within five years of the date of the order in this case, and a revision to the Power Supply Cost Adjustment tariff mechanism to provide for a sharing mechanism as advocated by the OCA. (MDU/OCA Joint Exhibit No. 1.)

107. Based upon the preponderance of the evidence offered in this proceeding, the Commission finds that the *Stipulation*, although offering certain reasonable terms and conditions, must be rejected for the reasons set forth below. Further, the Commission finds the evidence of record supports additional rate relief for MDU in the amount of $2,651,565 per annum (13.1% overall), as supported by the Commission findings below.

The Stipulation

108. Witnesses Mulkern and Zamora testified that one of the major benefits of the *Stipulation* was the proposal to phase-in the stipulated revenue increase over a three-year period, offered to mitigate rate shock concerns expressed by MDU's customers at the public comment hearing in contemplation of the 25% increase proposed. The phase-in approach was justified as a mechanism which would provide customers with the ability, during the first year of the phase-in, to plan and budget for the additional increase which would come in the second year and continue through the third year. Zamora acknowledged OCA had made concessions to the Company in the *Stipulation* regarding the return on equity and the Wygen III depreciation rate to obtain the phase-in provision. She also expressed her belief that the phase-in provision was an integral part of the *Stipulation* and that if the Commission had concerns and rejected the phase-in

provision it should reject the *Stipulation.* (Stipulation Comment Tr., pp. 142, 152.)

109. The *Stipulation* specifies 8.68%, the overall rate of return agreed to by the parties, as the interest rate for the deferred portion of the phased-in rate increase. The Commission finds this proposed interest rate on the deferred portion of the revenue increase to be excessive. If this rate reflects the time value of money, the Commission finds it highly unlikely that, if the Company needed to borrow money in the interim, it would have to pay an interest rate of 8.68%, given current economic and financial conditions. Below, the Commission will discuss its determination of an appropriate return on equity for this Company which will decrease the overall rate of return on rate base.

110. The phase-in proposal was ostensibly offered to mitigate the rate shock to come from implementation of the full revenue increase in 2010, by implementing a $1.8 million (8.93%) increase in the first year, and a $1,453,726 increase in the second year (6.6%) and continuing into the third year. (MDU/OCA Joint Exhibit No. 1, ¶¶ 16-17.) On closer inspection of the proposed phase-in and its associated interest on deferred revenues, it is clear that, in exchange for the transitory illusion of less rate shock in the first year of implementation, the net result is that customers will pay more overall than if the phase-in were not allowed. Zamora acknowledged this fact. (Stipulation Comment Tr., pp. 123-124.) Rather than ameliorating rate shock in the first year, the phase-in has the effect of continuing the rate shock effect for at least two years. Mulkern acknowledged on cross-examination that, in Year Two and Three of the phase-in, and taking into account the interest on the unamortized balance, customers would experience an increase of approximately 20.1%, (in comparison to current revenue levels), as opposed to the 16.1% increase they would realize in the first year if the *Stipulation's* revenue increase were put into effect with no phase-in. Only in Year Four would the increase decline to 16.1%. (Stipulation Comment Tr., pp. 42-43.) The phase-in proposal will also cause customers to experience rate instability as rates would be adjusted in Years One, Two and Four (and remaining high in Year 3). This will contribute to unnecessary customer confusion and may serve little purpose than to remind customers that rates continue to increase in subsequent years as a lingering effect of approval of the *Stipulation.* The Commission finds the provisions regarding the handling of possible under-recoveries or over-recoveries of the deferred balance at the end of the two-year amortization period, as referenced in ¶ 19 of the *Stipulation*, is unclear and leaves unresolved the appropriate rate treatment for an over-recovered balance. Based upon the findings set forth herein, the *Stipulation* provides no tangible rate relief benefits to customers, is not in the public interest and must be rejected. Simply put, the ratepayers will pay more if the phase-in is accepted, and it should not be. We further reject the notion, expressed at ¶ 25 of the *Stipulation*, that MDU should bind itself to file another rate case in five years. MDU is capable of deciding when it wants to file for additional rate increases without an arbitrary deadline, just as the Commission is fully capable of ordering MDU to file another case should we determine the need has arisen.

OCA'S Levelization Proposal

111. OCA witness Parrish offered a proposal to levelize or equalize the cost of the return on MDU's 25% Wygen III ownership interest over the expected depreciable life of the facility, as a mechanism to make all generations of MDU customers pay the same proportional

share of return MDU is entitled to earn on its portion of the Plant. The levelization proposal would lessen the rate impact of adding Wygen III to rate base during the initial years of its inclusion. Utilizing a fifty-year depreciable life for Wygen III, and a discount rate for the present value of 8.45% (OCA's recommended overall return on rate base) over the life of the Plant, levelization results in a return to the Company's investors of $2.8 million each year over the fifty-year life of the Plant. Parrish further testified that her levelization proposal assumes no change in the $2.8 million return to investors, regardless of future MDU general rate case filings. It also does not account for the costs of any additions to or repairs of the Plant during its useful life. Traditional depreciation methods would front load the return on the new Plant, resulting in early customers paying more than later generation customers, as the value of the Plant is depreciated over time. (Tr., pp. 626, 630-631.)

112. Parrish acknowledged this is the first case in which she has offered a levelization proposal and she was unaware of any prior Commission decision which addressed or approved a similar proposal. (Tr., p. 650.) She conceded that there is some uncertainty surrounding her proposal and that, over the first year of the Plant's operation, the return on the Plant would be less than 8.45%. (Tr., pp. 651, 657.) She further conceded the inherent unevenness in the plan: during the first ten years, customers would pay a lower return, with the return paid in later years being greater. She acknowledged implementing an 8.45% return over the fifty-year period could be problematic if certain events occurred, such as [i] debt and equity costs increasing into double digits which would make the discount rate insufficient in the marketplace, or [ii] the Company being unable to attract capital in the event the market did not accept her methodology. (Tr., p. 686.) Further Parrish noted in her summary testimony that the result of her levelization approach would be that MDU will collect about $55 million more from customers than it would if a nominal levelized return were used. (OCA Exhibit No. 216, p. 15.)

113. The Commission finds, based upon its review of Parrish's testimony and Gaske's rebuttal testimony in which he expressed a number of concerns regarding OCA's levelization proposal, that the proposal relies on too many assumptions to be approved. For example, to implement OCA's proposal, which is premised on a return of 8.45%, set at a time of historically low interest rates, we would be required to assume that this return will be reasonable over the 50-year life of Wygen III (an asset which was estimated by Parrish to quadruple the size of MDU's Wyoming electric rate base). The proposal may impose unreasonable constraints on future commissions who may feel compelled to maintain the fixed return level in the face of market conditions which may suggest otherwise. It could jeopardize the Company's ability to attract capital in the market place under such circumstances. It would have the effect of shifting part of the recovery of the return on Wygen III from the current generation of customers to later generations who will incur additional significant costs (approximately $55 million under the OCA's proposal). In addition, as noted by Gaske, the return earned during the initial year of Wygen III's inclusion in rate base and in subsequent years, under the levelization proposal, may be insufficient to provide a reasonable return to common equity investors, as interest on debt must first be paid to bondholders. (Tr., p. 737-739.) In all, in return for lower, and possibly inadequate initial returns on the Wygen III investment, in contemplation of $55 million of additional costs to be imposed on ratepayers over the years, accepting that we are in a time of low inflation and that it might not remain so over the 50-year life of the Plant, acknowledging that it is not only bad public policy but also not possible to attempt to bind future commissions,

either actually or morally, to a decision made today, and understanding that adopting the plan could make it difficult for MDU to raise needed capital in the future, we find that OCA's levelization proposal must be rejected as being unreasonable and contrary to the public interest. This finding is supported by the preponderance of the evidence of record in this case.

Overall Cost of Capital and Return on Common Equity

114. MDU witness Senger offered [i] the pro forma MDU capital structure as projected for the twelve month period ending December 31, 2009; [ii] the pro forma costs of long and short term debt; [iii] the costs of preferred stock, as projected through 2009; and [iv] the recommended cost of equity capital of 12.75% as determined by Gaske. (MDU Exhibit No. 107.) Using these figures to derive weighted average costs, the Company recommended an overall rate of return of 9.62%. OCA witness Wichmann adopted the Company's proposed pro forma capital structure and associated weighted costs of long and short term debt, and preferred stock. (OCA Exhibit No. 208.) She applied her recommended cost of equity capital of 10.4% to the pro forma capital structure and weighted costs of debt and preferred stock in arriving at her recommended overall rate of return of 8.45%. The uncontroverted testimony supports the use of the Company's pro forma capital structure and pro forma cost of debt and preferred stock, and we will do so in calculation of the authorized overall rate of return below.

Component	Percentage	Cost	Weighted cost
long-term debt	44.959%	6.79%	3.05%
average short-term debt	2.771%	3.77%	0.104%
preferred stock	2.5%	4.59%	0.115%
common equity	49.77%	10.4%	5.18%
TOTAL	100.00%		8.45%

115. MDU witness Gaske and OCA witness Wichmann provided their respective testimony and analyses in support of their calculations of a reasonable cost of common equity capital for MDU's Wyoming electric utility operations as summarized, *supra*. Both Gaske and Wichmann selected their respective group of comparable companies utilizing similar information sources and certain criteria or filters they believed would provide a sampling of companies that would reasonably serve as proxies for MDU's Wyoming electric operations. We note that twelve of Gaske's thirteen comparable companies were included in Wichmann's group of twenty two proxy companies. Both Gaske and Wichmann relied on several different DCF analyses as their primary methodologies in arriving at their recommended returns on common equity. Wichmann's ROE analyses resulted in a range of reasonableness of 9.05% to 10.93%. She recommended a ROE of 10.4%. In contrast, Gaske utilized the results of his two DCF analyses in arriving at a range of reasonableness of 11.56% to 12.95% and concluded that because of MDU's slightly above average risks a ROE of 12.75% was appropriate. (Tr., p. 174.)

116. The Commission finds Wichmann's testimony and analyses presented in calculating a range of reasonableness for MDU's ROE to be the most thoroughgoing, persuasive, and supported by the preponderance of the evidence. Gaske's explanation of his criteria in selecting his comparable companies, and notably his use of companies with at least 25% of generation from coal-fired plants, unreasonably narrows the group of comparable companies,

making the results of his analyses vulnerable to manipulation. He assigned additional risk to the Company because of its use of coal-fired generation in meeting a portion of its supply requirements, which he contrasted to its prior total dependence on purchased power contracts and the associated market volatility in serving its load requirements. This, on its face, appears to conflict with the Company's underlying rationale for purchasing a 25% interest in Wygen III, i.e., the mitigation of wholesale market volatility and its associated higher risks. The Commission is not persuaded by Gaske's argument that current economic conditions and the decline in the stock market have resulted in investors requiring a higher rate of return as they perceive more risk in common stock investments. (Tr., pp. 193-194.)[1] In contrast, Wichmann's determination of an appropriate ROE took into consideration the results of her DCF analyses and an identification and analysis of macroeconomic, financial and business risks facing MDU's regulated utility operations. (OCA Exhibit No. 201, pp. 23-28.) Taking these factors into account and recognizing [i] the narrowing of credit spreads between Aaa and Baa rated company securities and 30-year Treasury bond yields in 2009 (which suggests reduced risk and lower premium expectations by investors), and [ii] the regulatory paradigm in which MDU operates (which allows a significant portion of its costs to be recovered under tariffs, including the PSCA mechanism), Wichmann concluded the risks to MDU's Wyoming utility operations are average in comparison to other utilities, with the business risk being low to average. (Tr., p. 521.)

117. Although Wichmann recommended a ROE of 10.4%, the midpoint of her range of reasonableness is 9.9%. Chairman Minier asked her, given his concerns that the fed fund rate has been low for an extended period of time and the investment climate has been poor, whether it was unreasonable to consider a 9.9% ROE as being appropriate. She stated that any point within her range of reasonableness of 9.05% to 10.93% would be supported by her analysis. (Tr., p. 522.) Taking into consideration current economic conditions (as reflected in historically low interest rates which appear poised to continue, and indications that investors are returning to the equity market), the Commission finds and concludes that Gaske's recommended ROE of 12.75% is excessive and that a more reasonable ROE is appropriately closer to the midpoint of OCA's range of reasonableness. The Commission finds that a ROE of 10.0% for MDU's Wyoming electric utility operations is reasonable and appropriate. It meets the standards and requirements of the *Hope* and *Bluefield* cases. Based on our determination, that a 10.0% cost of common equity is supported by the preponderance of the evidence, we find the appropriate and reasonable overall rate of return for MDU's Wyoming electric utility operations to be 8.25%, calculated thusly:

Component	Percentage	Cost	Weighted cost
long-term debt	44.959%	6.79%	3.05%
average short-term debt	2.771%	3.77%	0.104%
preferred stock	2.5%	4.59%	0.115%
common equity	49.77%	10.0 %	4.977%

[1] The Commission's concerns regarding Gaske's credibility were further underscored by his willingness to testify under oath about an unrelated issue based on a text message received by another person in the hearing room. (Tr., pp. 732-736.) The Wyoming Administrative Procedure Act does not prohibit the Commission, as a learned tribunal, from accepting hearsay evidence, but, in this instance, acceptance would be far enough beyond what is reasonable that it would undermine the Commission's process.

TOTAL	100.00%		8.25%

Wygen III Depreciation Life

118. In its application, MDU proposed a 40-year depreciable useful life for Wygen III, stating the Company utilized the depreciation rate assigned by Black Hills Power & Light to the facility. The Company did not present an independent analysis of an appropriate depreciable life or corresponding depreciation rate for Wygen III and stated its recently completed depreciation studies did not include Wygen III because it was not constructed at the time the depreciation studies were prepared. (Tr., pp. 309-310.) Also, the Company originally proposed an annual depreciation rate for the Plant of 2.72% which translates to a 36.7 year life for the Plant. Mulkern subsequently testified on rebuttal that she was updating the depreciation rate for the Plant to 2.5% to reflect the 40-year life which the Company maintained was reasonable. (Tr., p. 756.) MDU witness Neigum acknowledged on cross examination that the Company had several older coal plants that have operated in excess of 50 years. From a technological standpoint, he was unaware of any reason which would limit a coal plant's life to 50 years. He stated a 40-year life for Wygen III was a "safe" estimate. (Tr., pp. 253-254, 281.)

119. OCA witness Zamora testified in support of a depreciable life of 50 years for Wygen III, basing her recommendation on the depreciation rates and lives assigned to similar coal-fired power plants by Rocky Mountain Power and Black Hills (which possesses plants similar to Wygen III). She stated that a 40-year life was a good starting point but that it was logical to extend the lives of these plants to address continued capacity deficits. (Tr., pp. 541, 563.) In discussing the depreciable lives of other vintage coal-fired plants in MDU's inventory, Parrish noted the current updated MDU depreciation studies reflect depreciation lives ranging from 48 to 66 years. (Tr., p. 645.)

120. The Commission finds the evidence presented on this issue supports a depreciable life of 50 years and a corresponding depreciation rate for MDU's share of Wygen III of 2.0% per annum. The Company presented no independent analysis to support its 40-year depreciable life, and based its decision on nothing more than the 40-year life assigned to Wygen III by Black Hills. We note the 40-year life assigned to Wygen III by Black Hills has not been brought before this Commission for consideration or approval. It will, however, be an issue for consideration in the pending Black Hills general rate increase filing. Our determination, based on the evidence in this case, is, we note, also consistent with the representations of OCA regarding useful coal plant lives in excess of 50 years for other coal-fired plants operated by Rocky Mountain Power and Black Hills. The use of a 50-year depreciable life for Wygen III is further supported by the Company's acknowledgment that the actual coal contract to serve the Wygen III Plant is set to run for 50 years. A 50-year life is within the range of reasonableness as developed in this case. (Tr., pp. 245, 254.) In addition, the Commission finds OCA's concession to accept a 45 year depreciation life for Wygen III understates the reasonable useful life of this generating facility, which will also be addressed herein.

Revenue Requirement

121. The OCA recommended a number of adjustments to the Company's proposed pro

forma revenues, O&M expenses, federal income taxes, other taxes and depreciation expenses. In her revenue requirement analysis, Zamora separated Wygen III expenses and investment costs from the rest of the revenue requirement to accommodate the OCA levelization proposal. Because the Commission rejects OCA's levelization proposal, it is unnecessary for us to consider Zamora's Wygen III adjustments separately from non-Wygen III-related expenses and investment costs.

122. OCA proposed an adjustment to usage which corrects an error identified by the Company regarding the revenues associated with the Rate 39 – Large General Service Class. This increases the Company's pro forma revenues by $18,726 to reflect additional revenue from demand and energy charges collected from the class due to an upward adjustment to usage. This adjustment simply corrects errors and was not contested by the Company. It is adopted by the Commission.

123. The Commission finds OCA's adjustment to purchased power and fuel costs associated with Wygen III is appropriate. It reflects updates in the gross tons of coal (629,355 tons) and uses a more updated cost of coal of $11.70 per ton. MDU witness Neigum testified to these statistics as representing the most current 2010 projections. (Tr., p. 237.) Mulkern provided updated coal expense information agreeing that the most recent updates should be utilized and stated they would match the update of the Wygen III Plant value she identified in her rebuttal testimony. (Tr., p. 746; MDU Exhibit No. 155.) Zamora agreed the most current Statement R price regarding the coal price should be used. (Tr., p. 558.) OCA's adjustment also incorporates a purchased power adjustment to reflect the correction to the Rate 39 usage.

124. In its initial testimony, OCA proposed an adjustment to Wygen III-related O& M expenses. During the course of the hearing, the parties agreed that updated information regarding Wygen III available at the time of the hearing should be incorporated into these adjustments. As to this specific adjustment, Zamora stated that she did not disagree with the updated amounts provided by Mulkern on rebuttal and said they should be adopted; and MDU agreed to the inclusion of the update. (Tr., p. 746.) The Commission finds the updated O & M expense total associated with Wygen III in the amount of $2,668,722 (as reflected in Commission Exhibit C), are appropriate and should be incorporated in the calculation of the revenue requirement.

125. OCA proposed to exclude $2,413 in advertising expense and industry dues, stating the expenditure of these funds are not needed in the provision of utility service and should more appropriately be shareholder funded. Company witness Mulkern, on rebuttal, testified the Company disagreed with the exclusion of the advertising expense in the amount of $1,683, arguing that institutional advertising benefits the communities it serves, thereby benefiting customers. (Tr., p. 743.) Commission Rule Section 248 addresses the issue of "promotional", "political" and "institutional" advertising and sets out the general prohibition of cost recovery in rates for these types of advertising, stating that such costs should be recovered by shareholders or owners of the utility. Commission Rule Section 248(e) specifically excludes certain forms of advertising from the general prohibition of cost recovery through customer rates, allowing recovery of the costs of advertising required by the public interest, as determined on a case-by-case basis. The Commission finds the advertising for which the Company seeks rate recovery

does not fall within the exceptions in Section 248(e). We do not find that the Company has supported its argument for recovery of these advertising expenses in this case. The denial of rate recovery for these advertising expenses and industry dues in the amount of $2,413 is in the public interest and is consistent with past Commission practice.

126. The OCA proposed to amortize regulatory commission (rate case) expenses over a ten year period, stating the normal time frame between MDU rate case filings is 8-15 years. (OCA Exhibit No. 209, p. 9.) Company witnesses proposed a three-year amortization period. The Commission finds the shorter amortization period of three years for recovery of regulatory commission expense is more reasonable and should be adopted as it provides for a more timely recovery of these expenses. The Commission anticipates that the historically lengthy period of time between MDU rate case filings may no longer be possible given the rapidly changing financial markets, which may require a more frequent review and evaluation of a reasonable cost of capital for MDU's Wyoming utility operations. It is also possible that carbon emission legislation and other regulatory issues might arise, which could necessitate further rate case filings. Many such issues may arise at the federal level -- beyond the power of the Commission or MDU to ignore or defer.

127. The Commission finds the Company has failed to support by a preponderance of the evidence its proposed generalized inflation adjustment to certain O&M expense accounts it had not individually adjusted for inflation. The Commission concurs with the position advocated by OCA that the adjustment of these specific expenses by a blanket percentage inflation factor is inconsistent with general past Commission practice of allowing adjustments for known and measurable changes. Therefore, the Commission adopts OCA's downward adjustment in the amount of $6,551.

128. OCA proposed to adjust O&M expenses to exclude certain costs related to one-time occurrences and prior period adjustments from 2007, and costs recovered through the Company's Load Management Program. Zamora corrected an error in the calculation of her prior period expense adjustment, reducing the total adjustment from $46,454 to $30,994. (Tr., p. 587.) Mulkern, on rebuttal, testified the Company did not take issue with OCA's adjustments regarding Account 902, Prior Period Adjustments from 2007, as corrected by Zamora; Account 925, the one-time occurring Wrench Ranch Fire expenses; or Account 908, Refrigerator Round Up Program Costs. Mulkern however, took issue with the exclusion of $3,499 associated with the Basin Electric Facilities Addition, which were related to transmission substation expenses, on the basis that even though the specific expense activity was non-recurring, such expenses regularly recur. (Tr., p. 744-745.) The Commission concurs with the Company's rationale that inclusion of the $3,499 in expenses associated with the Basin Electric Facilities Addition is appropriate and reflects the recovery of a recurring expense. The Commission finds the OCA's other adjustments to O&M expense accounts, as corrected, are uncontested, and therefore an adjustment in the amount of $27,495 is adopted.

129. The Commission finds OCA has supported its proposed adjustments related to Taxes Other Than Income, which included, [i] adjustments to Franchise Taxes of $125 and Gross Revenue Taxes of $57 to reflect OCA's Rate 39 revenue adjustment, and [ii] an adjustment to ad valorem taxes of $3,503 for Wygen III based on 2009 mill levies. The correct mill levy amounts

were not available to the Company at the time of the filing. We thus adopt a total net adjustment of $3,321.

130. MDU witness Mulkern offered a depreciation expense adjustment to reflect updated depreciation rates and associated expenses as shown in the Company's updated and very recently filed Electric Depreciation Study and Common Plant Depreciation Study. She stated the effect of utilizing the new depreciation rates would be to reduce her pro forma depreciation expense by $218,211 per annum. Mulkern stated factoring the effects of the revised depreciation expense on rate base, O&M expenses, and income taxes has the effect of reducing the Company's revenue increase by $220,358. (MDU Exhibit No. 142, pp. 2-3.) OCA witnesses accepted the Company's adjustment but recommended the Commission not accept or approve the updated depreciation studies because the OCA had insufficient time to review the studies in detail. OCA suggested that a more thorough review and full consideration of the studies would be best handled in the context of future rate proceedings. (Tr., pp. 564-566, 639-646.) Mulkern testified the Company did not object to the utilization of the revised depreciation expenses as set forth in the studies or allowing the OCA and Commission staff adequate additional time to review and inquire into the depreciation studies. (Tr., p. 759.) Based upon the concurrence of the parties in the adjustment to depreciation expense which reduced the Company's revenue requirement by $220,358 per annum, and general agreement that additional time for review of the updated depreciation studies is appropriate, the Commission finds the adjustment to depreciation expense should be accepted and factored into the calculation of the Company's revenue requirement. Further, the Commission finds the Company should be directed to refile its updated depreciation studies, as a separate docketed matter, so they can be reviewed, noticed, and additional proceedings can be held, if necessary, and a final determination can be made by this Commission regarding their reasonableness and possible approval of the studies.

131. In her supplemental testimony in support of the Company's amended application, Mulkern proposed an additional decrease to the Company's revenue request to recognize the impact of a proposed 50% bonus tax depreciation adjustment available for federal income tax purposes for certain qualifying property additions. The Company presented testimony to support its belief that its investment in Wygen III qualified for the bonus depreciation deduction. (Tr., pp. 297-300; MDU Exhibit No. 126, pp. 3-4.) Mulkern testified that the head of the Company's tax department, its internal auditors, and external tax experts had come to the common conclusion that the Company qualified for the bonus tax depreciation adjustment. (Tr., pp. 470-471.) OCA witness Zamora also recommended the bonus tax depreciation adjustment be adopted and incorporated in the calculation of the Company's revenue requirement. Zamora incorporated this deduction in her adjustments to deferred income taxes. She agreed her proposed adjustment, as reflected in her prefiled direct testimony, should be revised to reflect the update of MDU's Wygen III investment. (Tr. p. 559.) Mulkern's bonus depreciation adjustment was updated to reflect the updated estimate of MDU's Wygen III investment, as reflected in MDU Exhibit No. 139. OCA and MDU concurred that the most current updated numbers should be utilized for many of the Wygen III adjustments. The Commission concurs with the parties' position that an adjustment to reflect the 50% bonus tax depreciation deduction for the Company's Wygen III investment is appropriate and should be adopted.

132. The Commission further finds that OCA's testimony supports its adjustment to

deferred income tax expense to reflect the use of a full year of book depreciation -- in contrast to MDU's use of a half year -- in the calculation of the 50% bonus depreciation. The Commission concurs with OCA's adjustment. The use of a full year of depreciation is consistent with the normalizing of book depreciation in general and with specific reference to the calculation of deferred income tax expense. This adjustment increases book depreciation in the calculation and the annual tax effect of the difference between book and tax depreciation in the calculation, as depicted in the OCA calculation, is applied to deferred income tax expense and accumulated deferred taxes in the rate base calculation. The changes in book depreciation in the calculation are included in the current tax calculation.

133. The Commission accepts the OCA adjustment to synchronize interest expense in calculating current income taxes to reflect the interest deduction and the recovery of the interest expense necessary to finance the utility plant needed to provide service to the public. The Commission also agrees with OCA's adjustment to ad valorem taxes, which reflects the use of the 2009 mill levy for Wygen III, consistent with updated information. In addition, the Commission adopts the OCA adjustment to Bad Debt Expense based on a five year average of the bad debt expense ratio, which is applied in the revenue requirement calculation.

Rate Base

134. In its initial application, MDU presented a pro forma rate base for its Wyoming utility operations of $80,489,334, which it lowered in its amended application to $71,779,243, after taking into account the 50% bonus depreciation deduction. (MDU Exhibit No. 128, p. 7 and revised p. 7.) In her supplemental testimony, Mulkern calculated a revised pro forma rate base of $72,038,689 that took into account the depreciation rates in MDU's updated depreciation studies. (MDU Exhibit No. 150, 2nd revised p. 7.) During the hearing, the parties provided their respective calculations of MDU's Wygen III investment costs, which must also be factored into the calculation of an updated rate base. Zamora calculated the capital cost for Wygen III at $61.7 million. (Tr., p. 559.) Both Mulkern and Zamora agreed the most updated Wygen III capital costs should be used in determining the appropriate rate base. Zamora testified that, with an asset the size of Wygen III, it is appropriate to use the most current data. She further stated she had verified the Company's AFUDC calculation for 2010 but needed to verify the Company's AFUDC calculation for 2009. (Tr., pp. 559, 604.) The 2009 AFUDC calculation was subsequently provided in MDU late-filed Exhibit No. 157. On rebuttal, Mulkern provided an updated capital investment amount for Wygen III of $63,354,500, which includes AFUDC for 2009 and 2010. (Tr., pp. 312; MDU Exhibit No. 139.) The Commission concurs with the parties that the most current numbers must be used in calculating MDU's Wyoming rate base. Factoring in the adjustments to accumulated deferred depreciation to reflect the Commission use of a 50-year depreciation life for Wygen III (2.00% per year), the effects of the updated depreciation studies, and the accumulated deferred income tax, the Commission finds MDU's Wyoming electric utility rate base to be $71,863,966, as reflected in the following table which illustrates the Commission's calculated revenue deficiency of $1,703,954, We must thereafter make provision for payment by MDU of federal corporate income tax at the rate of 35%, which required the application of a "tax gross up" factor of 1.55612 to the revenue deficiency, yielding an additional revenue requirement of $2,651,565, all as based on the Commission's findings as set forth above.

	Operating Income and Adjustments		
A	MDU Initial Filing - Revenues	$	3,726,284
	Commission Adjustments		
B	Add Revenues		18,726
	Deduct (or add) Expenses		
C	Purchased Power and Fuel		(134,010)
D	Wygen III O&M Expenses		6,817
E	Advertising and Dues		(2,413)
F	Regulatory Commission Expense[2]		0.00
G	Remaining O&M Expenses (Inflation)		(6,551)
H	Miscellaneous O&M Expenses		(27,495)
I	Depreciation expense		(731,581)
J	Taxes Other Than Income		(3,321)
K	Deferred Income Taxes		8,557,461
L	Income Taxes[3]		(8,138,783)
M	Total Expense Adjustments		(479,876)
N	**Adjusted Test Year Operating Income**	**$**	**4,224,823**

	Rate Base		
O	**MDU Initial Filing - Rate Base**	$	80,489,334
	Commission Adjustments		
P	Plant Costs & Accumulated Depreciation		(67,907)
Q	Accumulated Deferred Income taxes		(8,557,461)
R	**Commission Determined Rate Base**	**$**	**71,863,966**

	Revenue Requirement for This Case		
S	Commission Determined Required Return on Rate Base at 8.25% [R x 8.25%]		5,928,777
T	Return Deficiency [S - N]		1,703,954
U	**Commission Determined Additional Revenue required [T x 1.55612][4]**	**$**	**2,651,565**

Rate Spread/Rate Design

135. Aberle described the Company's proposed rate spread. She testified the Company proposes to increase rates so that each customer class would produce revenue at the overall rate

[2] The Commission ordered no change from present practice.
[3] Includes Interest Synchronization
[4] The federal income tax gross-up factor. See discussion directly above this table.

of return with the exception of Schedule 24, the private lighting class, which is currently contributing more than the overall rate of return. The Company proposes to maintain Schedule 24 rates at their current levels. (Tr., p. 324.) She further stated the Company's proposal to move the customer charges and energy components of the various rates closer to their respective embedded costs, consistent with the results of its embedded cost of service study. She said this movement complies with the Commission's prior directives that such movement toward actual cost be made. (Tr., p. 325.) The OCA concurred with the use of the Company's class cost of service study results in apportioning its proposed revenue increase between the various classes, concurring that the Schedule 24 Class was exceeding the overall rate of return. OCA used the Company's model in developing its proposed rate design for each customer class with the objective of continuing movement toward recovery by each class of its respective cost of service, and movement towards, or recovery of, cost of service for the individual rate components for each class. (Tr., p. 544-546.) The Commission concurs with the general objectives of the parties in continued movement to cost of service based rates in developing their respective rate proposals. The Commission finds generally that setting rates with the objective of recovering the actual embedded costs incurred in providing service to the respective customer classes, and the rate components within the classes, is consistent with the past policy directives of this Commission.

136. MDU offered an alternative inverted block rate design for the Residential Rate Class, Schedule 10, as directed by the Commission in the prior rate case. The Company, however, recommended continuing its current rate design which contains a monthly base rate and a flat energy charge, but agreed that an inverted block rate design was acceptable as long as a minimum base rate of $25.00 was incorporated. MDU proposed an initial energy block of 1,000 kWh with the second block of energy use having an additional $0.02 per kWh differential. (MDU Exhibit No. 118, p. 12.) OCA proposed the use of an inverted block rate design with a minimum base rate/monthly charge of $25.50 and a similar $0.02 per kWh differential for all energy above the initial block of 1,000 kWh. (OCA Exhibit No. 209, pp. 26-27.) The Commission finds the use of an inverted block rate design for Schedule 10 will provide better pricing signals to customers and will promote conservation. The use of a $25.00 base rate/monthly charge is consistent with the results of the embedded cost of service study and provides additional movement towards recovery of the fixed costs associated with this rate component.

137. The OCA proposed a rate design for the Small General Service Class, Schedule 20, that provided for a $4.00 demand charge for the first 10 kW of usage and $10.00 per kW for usage over 10 kW for primary customers and a $4.50 demand charge for the first 10 kW of usage and $10.50 per kW for usage over 10 kW for secondary customers. MDU's current rate design does not provide for a separate demand charge for the first 10 kW of usage. MDU witness Aberle testified that OCA's proposal to implement a demand charge for the first 10 kW of usage for small use Schedule 20 customers would require the use of approximately 1700 demand meters at an installed cost of approximately $485,500, which she recommended not be implemented. (Tr., p. 764.) OCA witness Zamora subsequently acknowledged that her proposed rate design was not workable if demand meters were not in place for all customers in this class. (Tr., p. 548.) The Commission finds acceptable the proposal of the parties in the *Stipulation* at ¶ 21, that a Small General Service Rate 20 Non-Demand Metered provision is added and charged

separately under Schedule 20, with this provision being applicable to customers that do not currently have a demand meter. The proposal is reasonable and supported by the preponderance of the evidence. Given the small benefit to be derived, the expenditure of approximately $485,500 to purchase and install demand meters for small use customers in this class to track their demand usage is not supportable.

138. Members of the Irrigation Class, Schedule 25, raised concerns at the public hearings regarding the negative impacts of the current Irrigation rate design on their farming operations and their rates. In response, the Company proposed on rebuttal to bifurcate the current Irrigation Rate Schedule and offer an optional rate schedule under which Irrigation customers could take service under a time differentiated demand rate (time-of-day), or a more traditional non-time differentiated rate with a flat demand and energy charge. The Company witness testified that the optional schedule would provide an appropriate price signal due to an increase in demand charges and an incentive to customers to move their loads to off-peak periods. (MDU Exhibit No. 140, p. 4.) OCA proposed continuation of the current Schedule 25 with an increase in the monthly charge to $50.00, a reduction in the on–peak demand rate from $9.50 per kW to $8.30 per kW, continuing the off-peak rate of $3.00 per kW, and an increase in the energy charge. (OCA Exhibit No. 209, pp. 29-30.)

139. The Commission finds that a proposed bifurcated Irrigation Rate Schedule which offers optional time-of-day rates, with an on-peak hours period[5], and the use of a non-time-of-day rate design[6] which uses a flat demand charge, will provide irrigation customers with the ability to control their respective costs by determining which rate schedule is most compatible with their usage characteristics. Adoption of a bifurcated rate schedule proposal is consistent with and supported in the rebuttal testimony of Aberle. (Stipulation Comment Tr. p. 79-80.) The Company initially proposed continuation of a 12:00 noon to 8:00 p.m. on-peak period which it subsequently shortened to the four hour period proposed in the *Stipulation.* In response to cross-examination, Aberle expressed her reluctance to move off the 12:00 noon to 8:00 p.m. on-peak period as she did not have available data to support another time period. However, we find the Company failed to offer any evidence which would support continuation of the current eight hour peak period. (Tr., pp. 790-791.) On the contrary, the Company provided actual data which showed its system peaks occurring between 4:00 p.m. to 6:00 p.m., with the majority occurring at 5 p.m. (MDU Exhibit No. 122.) The Commission finds that use of a peak period that runs from 4:00 p.m. to 6:00 p.m. for Rate Schedule 26 is supported by the evidence and should be adopted. The Commission further finds a monthly Basic Service Charge of $50.00, an on peak demand rate of $8.30 per kW, and an off-peak demand rate of $3.00 per KW under Rate Schedule 26 are reasonable and supported by the evidence. The Commission Staff will monitor the use of Schedules 25 and 26 and their impact on irrigation customers.

140. The Commission also finds that irrigation customers should be allowed to select at any time the irrigation schedule under which they wish to be served; however, once the customer selects an irrigation schedule service must continue to be taken under that schedule for at least a one year period. The Company agreed this selection process which required the

[5] Rate Schedule 26 offered in the *Stipulation*
[6] Rate Schedule 25 offered in the *Stipulation*

customer to be bound for at least a year was acceptable and would address prior concerns expressed by the Company regarding the administrative burden and costs associated with having to reprogram its irrigation meters if customers were able to switch schedules more frequently. (Public Comment Tr., pp. 64, 88.) We expect some confusion among irrigation customers as a result of the adoption of Schedules 25 and 26. Consequently, at the public deliberations on April 14, 2010, the Commission directed the Company to send a letter to its irrigation customers prior to May 1, 2010, describing the new Schedules 25 and 26 and scheduling a meeting with its irrigation customers for the purpose of explaining, *inter alia,* how the schedules operate and how the rates were calculated and providing a full understanding of the possible consequences of adopting a particular schedule. We also directed that a customer making a selection prior to the date of the customer meeting shall not be bound by his initial election. The meeting must include a Commission staff member.

141. Based upon the above rate design and rate spread findings the Company is directed to file compliance tariffs that recover the approved revenue requirement from the various customer classes as follows:

Rate Class	Revenue Increase	
	$	%
Residential Service		
Rate 10	1,113,404.00	10.1%
Rate 11	10,968.00	2.8%
	1,124,372.00	9.9%
Small General Service		
Rate 20	803,672.00	21.5%
Rate 22	348.00	2.9%
	804,020.00	21.4%
Irrigation Service		
Rate 25	23,950.00	9.2%
Rate 26	new tariff: insufficient data[7]	
Large General Service		
Rate 39	726,901.00	15.8%
Lighting		
Rate 24	(29,889.00)	-34.9%
Rate 41	2,525.00	3.0%
	(27,364.00)	-16.1%
Total Wyoming Electric	**2,651,879.00**	**13.1%**

Tariff Revisions

142. The Commission finds OCA has supported the use of separate demand and energy components for purchased power and fuel recovered under the PSCA mechanism. On rebuttal,

[7] Rate 26 is newly created. There is therefore no "revenue increase" for this class and no data upon which to base a percentage of increase. See the discussion of the rates for this class at ¶ 139.

Aberle provided an alternative proposal to collect the demand charges associated with the power purchase agreement from the cost of service component of each rate with only the prospective changes in the demand component billed through the energy charge, stating the demand costs do not fluctuate significantly from year to year. The Commission finds the base cost of power supply, including the demand, energy and transmission components are those established in this case as a result of the Commission's determinations. The demand and transmission components that change as a result of changes to MDU's power purchase agreement, and filed under the Company's PSCA tariff pursuant to Commission Rule Sections 249 and 250, will be reflected in the energy or demand components, as applicable, and will be allocated to the primary and secondary service customer classes.

143. The Commission further finds OCA has supported its recommendation that the use of the term "Base Rate" in all applicable retail rate schedules be replaced with the term "Basic Service Charge," as it will eliminate confusion that currently arises from the use of the term "base rate" in other contexts in the calculation of various rates.

Power Supply Cost Adjustment (PSCA) Mechanism

144. In its initial testimony, OCA proposed a revised PSCA mechanism which would accommodate the purchased power and fuel costs associated with MDU's interest in Wygen III. OCA argued that Commission Rule Sections 249 and 250, which provide for the recovery of commodity and commodity-related costs by utilities that purchase all their power requirements from a wholesale provider, do not provide for the recovery of accumulated production costs from self-generation and the subsequent passing of them on to customer. Zamora stated these production costs are usually addressed at the time base rates are computed in a general rate case. (OCA Exhibit No. 209, p. 33.) She recommended the adoption of a revised PSCA mechanism that incorporates a dead band and sharing mechanism as more fully described in the summary of her testimony, above. The Company argued that its current PSCA tariff language would accommodate its partial self-generation status and that Rules 249 and 250 do not preclude recovery of production or fuel costs. The Company further disagreed with the incorporation of the dead band and the sharing mechanism as proposed by the OCA. (Tr., pp. 748-754.) As shown in the *Stipulation* at ¶ 26, the Company and OCA negotiated a revision to the PSCA mechanism consistent with OCA's proposal of incorporating a dead band and sharing mechanism. The Commission rejected the *Stipulation*, and with it, the above-described mechanism. We therefore infer that MDU retains its initial opposition to OCA's revised PSCA mechanism.

145. The Commission finds OCA's proposal of a revised PSCA mechanism which incorporates a dead band and a sharing mechanism falls under the innovative and non-traditional ratemaking provisions contained in W.S. § 37-2-121, which states in part:

> Any public utility may apply to the commission for its consent to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission may consider and approve proposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services,

facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest.

This statute sets up a mechanism whereby it is the utility which must apply for innovative, incentive or nontraditional rate making methods. The Commission is limited to consenting (or not) based on substantial evidence that the public interest is thereby served. MDU has neither applied for nor proposed the adoption of OCA's revised PSCA mechanism. The Commission finds that we are precluded under W.S. § 37-2-121 from imposing such a mechanism on the Company. MDU may make such a filing in the future. However, the Commission advises the Company that it will not be receptive to a filing under Rule Sections 249 and 250 which seeks recovery of items or costs for which we have not previously allowed recovery under these Rules.

Net Metering Tariff

146. In response to the Commission's inquiry regarding the need for an updated calculation of the Company's avoided cost for purposes of its net metering tariff, the Company expressed its belief that the Company's avoided cost would not change as a result of its acquisition of an interest in Wygen III in meeting its load requirements. Aberle argued the Company's current avoided cost is based on its Black Hills PPA. Any power needed over and above its Wygen III production will be purchased under the PPA; and this, she offered, establishes the marginal cost MDU avoids. (Tr., p. 335.) Aberle subsequently conceded the inclusion of the generation costs of Wygen III in its avoided cost calculation would result in a decrease in its current avoided costs. (Tr., pp. 338, 344-345.) We note that, when the MDU system is not utilizing its entire share of Wygen III's output, and a net metering customer is producing electricity, MDU avoids nothing with reference to the PPA. The Commission finds the evidence of record clearly supports the need for the Company to recalculate its avoided cost and submit a revised net metering tariff. The Company is directed to submit its proposed revised avoided cost and net metering tariff for Commission consideration within sixty (60) days of the issuance of this *Order*.

Conclusions of Law

147. MDU is duly authorized by the Commission to provide retail electric public utility service in its Wyoming service territory under certificates of public convenience and necessity issued by the Commission. MDU is an electric public utility as defined in W.S. § 37-1-101(a)(vi)(C); and, as such, the Commission has the general and exclusive jurisdiction to regulate MDU as a public utility in Wyoming under W.S. § 37-2-112.

148. Proper public notice of these proceedings was given in accordance with the Wyoming Administrative Procedure Act, W.S. § 37-2-203 and the Commission's Rules, especially Section 106 thereof. The public hearings were held and conducted pursuant to W.S. §§ 16-3-107, 16-3-108, 37-2-203, and applicable sections of the Commission's Rules. The intervention petition of the City of Sheridan was properly denied. Intervenor OCA became a party to the case for all purposes.

149. The Commission concludes, based on its findings above, that the offered *Stipulation* must be rejected as not being in the public interest.

150. The preponderance of the evidence of record, as shown in the Commission's findings above, supports the Commission's conclusion that MDU's current rates for electric service are inadequate and unremunerative, and should be increased in the amount of $2,651,565 per annum, the same to be effective for usage on and after May 1, 2010.

151. The Commission concludes an overall rate of return on rate base of 8.25%, based upon a reasonable return on equity of 10.0%, for MDU's Wyoming electric utility operations is just and reasonable and in the public interest. We conclude that these rates satisfy the capital attraction standards of the *Hope* and *Bluefield* cases, discussed, *supra*.

152. The Commission further concludes the rates approved herein will allow MDU to continue to provide adequate, safe and reliable service. The rates approved herein are just and reasonable, and the recovery of the rates pursuant to the rate spread and rate design adopted herein will not result in undue discrimination as between customer classes because they are based on the respective cost of serving each customer class consistent with the provisions of W. S. § 37-3-112.

153. The Commission concludes the tariff modifications approved herein are supported by the preponderance of the evidence of record and should be approved as being in the public interest.

IT IS THEREFORE ORDERED:

1. Pursuant to the Commission's deliberations held on April 14, 2010, Montana-Dakota Utilities Co. is authorized to implement a general electric rate increase of $2,651,565 per annum, effective for usage on and after May 1, 2010, and done in the manner approved hereinabove.

2. Based on the Commission's deliberations, MDU filed compliance tariffs to reflect the approved general rate increase, the rate spread, the rate design and the tariff modification findings set forth above. The compliance tariffs were approved by open meeting action taken on April 27, 2010, to be effective for service rendered on and after May 1, 2010.

3. The Company is directed to refile its updated depreciation studies within thirty (30) days of the issuance of this *Order* for consideration in a separate docket.

4. The Company is directed to submit its proposed revised avoided cost and net metering tariff for Commission consideration within sixty (60) days of the issuance of this *Order.*

5. With its compliance tariff filing, the Company submitted a proposed letter to Irrigation customers as described above in ¶ 140. Having directed several needed revisions to

draft letter notice, the Commission directs that the Company use the revised letter and shall hold the scheduled informational meeting as directed by the Commission.

6. This *Order* is effective immediately.

MADE and ENTERED at Cheyenne, Wyoming, on May 26, 2010.

PUBLIC SERVICE COMMISSION OF WYOMING

ALAN B. MINIER, Chairman

STEVE OXLEY, Deputy Chairman

KATHLEEN A. LEWIS, Commissioner

(SEAL)

ATTEST:

DAVID J. LUCERO, Assistant Secretary

Service Date: May 12, 2005

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

* * * * *

IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO., Application for Authority to Increase Rates for Natural Gas Service in its Montana Service Areas	))))	UTILITY DIVISION DOCKET NO. D2004.4.50 ORDER NO. 6580a

* * * * *

FINAL ORDER

APPEARANCES

FOR THE APPLICANT

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FOR THE INTERVENORS

Mary Wright, Staff Attorney, Montana Consumer Counsel, 34 West Sixth Avenue, P.O. Box 201703, Helena, Montana 59620-1703, for the Consumer Counsel.

FOR THE COMMISSION

Dave Burchett, Rate Analyst, Will Rosquist, Rate Analyst, and Martin Jacobson, Staff Attorney, 1701 Prospect Avenue, P.O. Box 202601, Helena, Montana 59620-2601.

FINAL ORDER BEFORE

GREG JERGESON, Chairman
BRAD MOLNAR, Vice-Chairman
DOUG MOOD, Commissioner
ROBERT H. RANEY, Commissioner
THOMAS J. SCHNEIDER, Commissioner, Hearings Examiner

I. INTRODUCTION

1. On April 1, 2004, Montana-Dakota Utilities Co. (MDU) filed with the Montana Public Service Commission (PSC) an application to increase its rates for natural gas service in Montana. MDU requested an increase in annual non-gas revenues of $1,513,048, approximately 1.8% of test year revenues of $83,358,279. If approved, the increase would affect approximately 73,150 Montana natural gas customers. MDU asserted it needs additional revenue to recover increased operating and maintenance expenses associated with higher labor and benefit costs and depreciation expense. MDU stated that in spite of cost control efforts, increases in operating and maintenance expenses have made current rates insufficient to compensate MDU for operating its Montana natural gas distribution system. MDU's last general rate increase in Montana occurred in 2002, in PSC Docket No. D2002.5.59.

2. MDU's proposed rate increase would affect customer classes by the following amounts and percentages:

Table 1

Customer Class	Amount	Percent Increase
Residential	$969,849	1.9%
Firm General Service	$543,199	1.9%
Small Interruptible	$0	0.0%
Large Interruptible	$0	0.0%
Total	$1,513,048	1.8%

3. On May 21, 2004, Montana Consumer Counsel (MCC) petitioned for intervention. On June 8, 2004, the Commission granted MCC's petition. No other party intervened in the proceeding.

4. During the course of procedures, MDU and MCC reached an agreement regarding depreciation rates, which resulted in a reduction to MDU's initial rate increase request from $1,513,048 to $1,084,052.

5. A public hearing was held in Billings, Montana, on November 17, 2004, before Commissioner Tom Schneider, acting as hearings officer. Six witnesses testified on behalf of

MDU and three witnesses testified for MCC. Four witnesses returned for MDU and testified in rebuttal to the MCC.

6. MDU's post-hearing brief provided a statement of the case and a summary of testimony of its six witnesses. Bruce T. Imsdahl, President of MDU, presented an overview of Montana operations, including the need for a general rate increase. Craig A. Keller, Vice President, Controller and Chief Accounting Officer presented the Company's capital structure and associated capital costs. He documented a weighted cost of capital of 10.038%. The cost of equity capital for MDU's Montana operations was presented by J. Steven Gaske, President of Zinder Companies. Mr. Gaske proposed an allowed return on equity of 11.50%. Paul W. Conley of Towers Perrin described MDU's Supplemental Income Security Plan, or SISP, and discussed the reasonableness of the compensation paid to key MDU employees. Rita A. Mulkern presented MDU's per books cost of service for MDU for test year 2003. Finally Tamie A. Aberle presented an allocated class cost of service study and supported the Company's proposed rate design.

7. MCC's three witnesses were Albert E. Clark, Stephen E. Hill and George L. Donkin. Albert E. Clark presented the overall revenue required advocated by MCC. Mr. Hill argued for a cost of equity capital for MDU of 9.75% and Mr. Donkin reviewed the cost of service studies and proposed alternative rate design.

8. In rebuttal MDU's Mr. Gaske and Mr. Keller offered explanations of why MCC's cost of equity capital was unreasonable. Ms. Mulkern offered an explanation of why Mr. Clark was wrong and Ms. Aberle presented testimony opposing Mr. Donkin's criticisms.

9. On January 14, 2005, MDU and MCC submitted a Stipulation, representing the agreement would fairly and equitably resolve the issues between them and would result in just and reasonable rates.

II. FINDINGS OF FACT, DISCUSSION, AND DECISIONS

A. REVENUE REQUIREMENTS

MDU Prefiled Direct Testimony

Bruce T. Imsdahl

10. Mr. Imsdahl, President of Montana-Dakota Utilities Co., gave a brief opening statement on the overall operations of MDU and its need for a general rate increase. Mr. Imsdahl

stated that the current cost of providing natural gas service to MDU's Montana customers is not adequately reflected in the currently authorized rates.

11. Gas costs, which are passed to customers dollar-for-dollar are not a part of this filing. Gas costs account for approximately 78% of a typical residential bill for gas service. Distribution costs, he said, which are regulated by the PSC include operation and maintenance expenses, depreciation, taxes, and a component for the opportunity to earn a return on investment are typically 22% of a residential bill.

12. Mr. Imsdahl concluded by saying that he believes the proposed rates are just and reasonable and is reflective of the total costs being incurred by MDU in providing natural gas service to its Montana customers.

J. Stephen Gaske

13. Dr. Stephen Gaske, President of Zinder Companies, recommended an overall rate of return of 10.038 %, with an 11.50% return on common equity for the cost of capital for MDU. He argued that because MDU must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other investments with similar risks. The Discounted Cash Flow (DCF) method, he stated, provides a good measure of the returns required by investors in the financial market. The DCF method requires a market price of common stock to compute the dividend yield component of the DCF analysis. Because MDU is a division of MDU Resources and does not have publicly-traded common stock, a direct market-based DCF analysis of MDU as a stand alone company is not possible. Dr. Gaske said he then selected a group of natural gas distribution companies with publicly-traded common stock as a proxy group for purposes of estimating the cost of common equity for MDU's Montana natural gas distribution operations.

14. Dr. Gaske used the risk premium approach because he believes this approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. He said he believes investments in common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income left after bondholders have been paid. In the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of the bondholders. He said he believes this superior standing

provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when bonds mature. Dr. Gaske concluded the risk premium approach estimates the returns investors require from common stocks by utilizing current market information readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

15. In comparing the risk faced by MDU's Montana natural gas distribution operations with the risk faced by the proxy group companies Dr. Gaske found four broad categories of risk that concern investors: 1) business risk, 2) regulatory risk, 3) financial risk, and 4) market risk.

16. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists, according to Dr. Gaske, because forecasts of both demand and costs are inherently uncertain. MDU's gas distribution operation faces some risks that distinguish it from many other distribution companies. MDU's natural gas distribution operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. The typical proxy company is somewhere between approximately 6 and 42 times the size of MDU's natural gas distribution operations.

17. With its small revenue base, stated Dr. Gaske, MDU is subject to slightly greater risk than a major employer or industry, such as a mining operation or refinery might experience in a downturn that would significantly affect overall employment and income in the areas served.

18. Regulatory risk is closely related to business risk and might be considered just another aspect of business. Dr. Gaske stated that to the extent that the market demand for a natural gas distribution company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may set the rates at a level that will not allow full cost recovery. Regulation, he said, often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries. Regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the general gas distribution industry. The regulatory climate in Montana, according to Dr. Gaske, is generally viewed as being average among regulatory jurisdictions.

19. Financial risk exists to the extent a company incurred fixed obligations in financing its operations. Dr. Gaske stated that these fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the

effects of business and regulatory risks. MDU filed a common equity ratio of 53.0% which is very close to the mean and median common equity ratios of the proxy companies. This common equity ratio, combined with its bond ratings, suggests average financial risk for MDU.

20. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the country. MDU's degree of market risk is not significantly different from that of the companies in the natural gas distribution comparison group.

21. In conclusion Dr. Gaske said he believed that his analyses indicate that an appropriate rate of return on common equity for MDU's Montana natural gas distribution operations for this filing would be 11.50%. This recommended return reflects his assessment that MDU's overall risks are significantly higher than those of the proxy group.

Craig A. Keller, CPA

22. Craig Keller, MDU Vice President, Controller and Chief Accounting Officer, states that the capital structure and the associated costs serve as the basis for his recommended overall rate of return requested by MDU in this rate filing of 10.038%. The basis for the requested 11.50% return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. Gaske. The balance sheet and income statement developed by Mr. Keller is used by MDU's witnesses in this case.

Paul W. Conley

23. Paul Conley, of Towers Perrin, supplied testimony regarding MDU's Supplemental Employee Retirement Program (SERP) called the Supplemental Income Security Plan (SISP) as part of its total executive compensation program. SISP is designed to attract and retain key employees in a number of positions within MDU and provide equitable retirement benefits for those employees. Participants are officers and senior managers of MDU Resources and Montana-Dakota Utility. These employees have the primary management responsibility for keeping MDU competitive in the industry and maintaining an adequate supply of low-cost energy for its customers.

24. Mr. Conley said that retirement benefits normally provided in the qualified plan are limited by IRS regulations and are not provided in the full amount called for in the qualified plan

design. Supplemental programs like SISP help to restore the retirement benefits to their intended level, and ensure a competitive overall retirement program. The removal of SISP, according to Mr. Conley, would unduly hamper the company from meeting its overall reward objectives. Programs such as SISP, Mr. Conley stated, represent a normal cost of doing business.

25. Towers Perrin considers an organization that is within plus or minus 10% of the market 50th percentile to be within the competitive range. Because MDU's program elements fall within plus or minus 5% of the market 50th percentile, Towers Perrin found the overall program to be competitive and appropriate. Removal of any of these elements would represent a competitive shortfall in MDU's ability to attract and retain qualified executives. Mr. Conley concludes that SISP is an important element for a balanced and competitive compensation package for executive employees who tend to be experienced employees who consider retirement benefits an important part of a total compensation package.

Rita A. Mulkern

26. Rita Mulkern, the Regulatory Analysis Manager for MDU, presented MDU's per books cost of service for MDU's 2003 test year along with a pro forma cost of service reflecting known and measurable changes that will have occurred to that cost of service by year end 2004.

27. Montana gas operations had a return on rate base of 9.391% for the twelve months ended December 31, 2003. Ms. Mulkern stated that all adjustments were calculated on either a Montana specific basis or on a total company basis and allocated to Montana.

28. Ms. Mulkern said that MDU utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense, and rate base to the jurisdiction as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as have previously been used in PSC proceedings and are based on a principle of assigning and/or allocating costs to the cost causer.

29. Ms. Mulkern said the pro forma adjustments to operating revenue, expenses and rate base were based on known and measurable changes occurring by December 31, 2004, and conforms to past PSC practices outlined in Rule 38-5-175 ARM. Ms. Mulkern said that, in her opinion, all of the adjustments are reasonably certain to occur and can be measured with reasonable accuracy meeting the criteria of known and measurable.

MCC Prefiled Testimony

Stephen G. Hill

30. Mr. Stephen Hill, MCC expert witness, broke his testimony into four sections. First, he discussed the cost of capital standard as a measure of the return to be allowed for regulated industries, and he reviewed the current economic environment in which the equity return estimate is made. Second, he looked at MDU's actual capital structure in comparison to capital structures employed by the natural gas industry. Third, he evaluated the cost of equity capital for similar-risk operations using Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Modified Earnings-Price Ratio (MEPR), and Market-to-Book Ratio (MTB) analyses. Fourth, he discussed the cost of capital testimony of Company witness, Dr. Stephen Gaske, underscoring the shortcomings he sees contained therein.

31. Mr. Hill's testimony presented a cost of capital analysis for gas distribution operations in Montana. He estimated that the equity capital cost of a utility similar in risk to MDU to be in the range of 9.25% to 9.75%. Within that range, Mr. Hill said a reasonable point of estimate of the current cost of equity capital for MDU would be at the upper end of that range, or 9.75%. He said that data confirm that his 9.25% to 9.75% equity return range for the gas distribution operations under consideration is conservative.

32. Mr. Hill stated that MDU witness Gaske based his recommendations on the results of three DCF analyses, which he checks with a risk premium analysis and a comparable earnings analysis. Mr. Hill said Dr. Gaske's DCF methodologies are flawed and produce results which are overstated due to a heavy reliance on projected earnings growth rates.

33. According to Mr. Hill, even though Dr. Gaske's DCF produces overstated results, he believes they are more reasonable results than his Risk Premium analysis, which he thinks significantly overstates MDU's cost of equity capital. He reasoned that it is based on very long-term return data not necessarily representative of current risk/return relationships and it attempts to measure a return appropriate for all stocks, not utility stocks, which are considerably less risky than the broad market measure and that it relies on historical return data for small companies that are of questionable origin and do not apply to utilities.

34. Mr. Hill stated that Dr. Gaske's third methodology, which he terms his "Alternative Equity Investment Analysis," is simply a comparable earnings analysis that uses the earned

returns of unregulated industrial firms as a gauge of the return for MDU. Mr. Hill said that this comparison is inappropriate because those firms are not of comparable risk to MDU.

Albert E. Clark

35. The purpose of Mr. Clark's testimony was to present conclusions and recommendations to the PSC regarding MDU's test year revenue requirements. He addressed all revenue requirement issues raised by this application except the appropriate capital structure and cost of capital which were addressed by Mr. Hill.

36. MDU has proposed to use a historical test year ended December 31. 2003. Mr. Clark accepted the use of this historical period, as adjusted, for the test year in this case. He stated MDU has made many adjustments to the historical test year under the guise of being "known and measurable." In reality, according to Mr. Clark, MDU has made substantial post-test year adjustments that are based solely on the 2004 operating budget and pro form the historical test year into a budgeted 2004 test year. He said a budget is not an appropriate basis to be used to determine known and measurable changes as contemplated by the PSC.

37. Mr. Clark stated that MDU's requested annual revenue increase is excessive and should not be allowed by the PSC. He concluded that the PSC should order a revenue decrease of at least $248,245. Direct testimony of MDU's witness Bruce T. Imsdahl was that the primary reason for the requested increase is increased operating expenses driven largely by increases in labor, benefit costs, and depreciation expense. Mr. Clark states that the labor costs and the benefit costs, among other costs, are overstated in MDU's filing and depreciation expense (i.e. the proposed new depreciation rates) are absolutely unsupported anywhere.

38. Revised depreciation expenses were provided by MDU. That calculation produces a requested revenue increase of $1,084,052, or a reduction of $428,610. Mr. Clark said that, since MDU totally failed to offer any support for the originally requested overall increase in depreciation rates, if the parties are unable to reach a stipulation or the PSC opts not to approve the agreed upon rates, he recommends that the PSC specifically approve the existing depreciation rates.

39. The first adjustment Mr. Clark proposed is to eliminate the cost of gas from the operation and maintenance expenses and from sales revenues. That results in the removal of

$64,084,689 from operation and maintenance expenses and $64,084,500 from sales revenues. The very slight difference between these two amounts is *de minimus*.

40. Mr. Clark's next adjustment was to bring the net margin from merchandising operation "above the line" so that there is no chance that Montana ratepayers are subsidizing this non-utility, unregulated operation. The reported number for MDU is $1,582,258 for calendar year 2003. Mr. Clark allocated a portion of this amount to the gas utility and then allocated a portion of the gas utility amount to Montana. His adjustment increases other operating revenue by $81,339.

41. Mr. Clark proposed to reduce test year labor expense by $89,110. The basis for this adjustment is to use a percentage increase of 5.36% in lieu of the 6.82% used by MDU to calculate what is essentially a 2004 labor expense.

42. Mr. Clark proposed an adjustment to test year payroll related taxes. MDU proposed to measure test year payroll related taxes as a percentage of per books gas utility to per books gas utility payroll expense multiplied by the pro forma Montana payroll expense. The 2003 Montana gas operation payroll taxes were compared to the 2003 Montana payroll expense. The resulting ratio of 7.2052%, stated Mr. Clark, is applied to his proposed pro forma test year labor expense and compared to the pro forma payroll taxes included in MDU's filing. His adjustment is ($3,574).

43. MDU proposed to include $257,163 in test year expenses for the cost of the Supplemental Income Security Plan ("SISP"). Mr. Clark proposed to disallow this adjustment. The SISP is a plan to increase the retirement benefits of selected officers, directors and senior executives of MDU Resources and its subsidiaries and affiliates. MDU indicated out of a total of 1,063 employees, only 53 are SISP participants. Mr. Clark said, as a matter of public policy, it is not equitable to ask ratepayers to bear the additional costs associated with the provision of retirement benefits that exceed ERISA limitations.

44. Mr. Clark proposed to reduce MDU's pro forma insurance expense by $66,556 to remove the premiums associated with the Directors' and Officers' Liability insurance policies. The sole purpose of this request by MDU is to protect stockholders against malfeasance by MDU's directors and officers. Ratepayers do not benefit from this coverage in any way according to Mr. Clark.

45. Next Mr. Clark proposed to reduce MDU's consumption of utility services. This consumption is used by MDU to move gas, light its facilities, heat and cool its facilities and perhaps other uses as well. He proposed a reduction in pro forma operation and maintenance expenses by $2,574.

46. A reduction in MDU's claimed pro forma uncollectible expense by $39,900 was proposed by Mr. Clark. He proposed to remove years 2001 and 2002 because they are far out of line with normal uncollectible expenses, one too high and one too low. He said years 1999, 2000 and 2003 appear to be more representative.

47. Next Mr. Clark proposed to increase late payment revenues by $11,145. Mr. Clark states that, for twelve months ended May 2004, the actual late payment revenues are $50,977 for Montana gas operations. MDU proposed to use $38,932 which is actual recovery during 2003. He said the more recent experience should be used for ratemaking purposes.

48. The last adjustment to the pro forma income statement was to synchronize the interest expense with the capital structure and the rate base plus non-base construction work in progress. The impact of that adjustment was to increase current income tax expense by $15,077.

49. Mr. Clark concluded that MDU's requested revenue increase of $1,512,662 (reduced to $1,084,052 after taking into account the agreement relative to depreciation rates) is excessive and he recommended that the PSC reject MDU's request for that level of increase. He further concluded that MDU is actually over-recovering $248,245 from its Montana gas operations on a pro forma basis. He recommended that the PSC order a revenue decrease of $248,245. Mr. Clark stated that his conclusions and recommendations are based on his analysis of MDU's filing, supporting data and information, and the use of cost of capital and capital structure recommendations of MCC witness Mr. Stephen G. Hill.

MDU Rebuttal Testimony

50. In rebuttal MDU provided four witnesses to the MCC. Dr. Gaske and Mr. Keller explained why MCC witness Hill's proposed capital structure and cost of equity capital were unreasonable. Ms. Mulkern addressed issues raised by MCC witness Clark and explained why she felt many of Mr. Clark's adjustments to MDU's revenue requirements were not only unreasonable but in some instances simply wrong. Finally, Ms. Aberle disagreed with MCC

witness Donkin's criticisms of MDU's class cost of service studies and proposed rate design and explained why she felt they were misplaced.

Stipulation

51. The Stipulation between MDU and MCC stated that for purposes of settling the contested issues in this proceeding, a fair and equitable resolution of the issues that would result in the establishment of just and reasonable rates would be structured as follows. First, MDU should be authorized to increase the Basic Service Charges contained in its rates 60 and 70 as follows: Rate 60, by 10 cents per month; Rate 70, small meter, by 40 cents per month; and Rate 70, large meter, by 80 cents per month. These rate changes are estimated to generate an additional $124,625 in annual revenue.

52. Second, the stipulated rate change should be implemented immediately, if possible for services rendered on and after February 1, 2005. This provision was an essential component of the Stipulation for MDU as no interim rate relief of any kind was authorized in this docket.

53. Third, after the completion of contested case proceedings in this docket, the Commission should, in its discretion, issue a final order approving, adopting, and implementing the terms of this Stipulation.

54. After careful review the Commission finds that the annual revenue increase proposed in the Stipulation to be just and reasonable.

B. COST OF SERVICE AND RATE DESIGN

Introduction

55. As noted above in Table 1, MDU initially proposed class revenue increases of $969,849 and $543,199 for the residential and firm general service rate classes, respectively. MDU also proposed various changes to its operating rules, including a distribution delivery stabilization mechanism to correct for over/under collections of distribution delivery charge revenues due to weather variation.

56. MDU's sales tariffs are Rate 60 (residential), Rate 70 (firm general service), Rate 71 (small interruptible) and Rate 85 (large interruptible). Transportation tariffs include Rate 81 (small interruptible) and Rate 82 (large interruptible). Other tariffs include Rate 72 (optional seasonal general service), Rate 80 (interruptible electric generation transportation service), Rate

93 (special gas service), Rate 100 (conditions for service), Rates 119 and 120 (line extension policies), Rate 88 (gas cost tracking procedure) and Rate 89 (universal system benefits charge).

57. MDU's last general natural gas rate case occurred in 2002, Docket No. D2002.5.59. In that case, MDU requested an increase in annual revenues of $3,642,269. MDU and MCC, the only intervener, stipulated to an annual revenue increase of $2,393,517, approximately 4.26%. The stipulation increased residential class revenues 4.45%, firm general service class revenues 3.85% and small interruptible class revenues 8.43%. The stipulated rate design increased the residential Basic Service Charge from $5.00 per month to $6.25 per month. The firm general service Basic Service Charges increased from $8.00 per month to $10.00 per month for customers with meters rated under 500 cubic feet per hour, and from $17.00 per month to $21.25 per month for customers with meters rated 500 cubic feet per hour or more. The Commission approved the stipulation, finding its rates fair, just and reasonable.

58. MDU's next most recent general rate case, before Docket D2002.5.59, was Docket D95.7.90. MCC was the only intervener to testify on cost of service and rate design issues. The different methodological approaches for estimating non-gas costs that were debated by MDU and MCC in Docket D95.7.90 are virtually identical to the issues debated in this case, as discussed below.

59. Although Commission rules require applications for rate increases to include a marginal cost of service analysis (ARM 38.5.176), MDU's April 2004 application relied on an embedded cost study. MDU requested a waiver of ARM 38.5.176, asserting that a marginal cost of service study was not relevant to its application because its distribution system is static and, therefore, an embedded cost of service study provides a more appropriate measure of costs on a class of service basis. On May 6, 2004, the Commission denied MDU's request for a waiver of ARM 38.5.176. MDU submitted its marginal cost of service analysis on May 26, 2004.

60. ARM 38.5.176 describes the basic marginal cost model the Commission uses to develop and organize cost of service testimony. That model is summarized in Table 2. Costs are organized first by functions that identify sources of marginal costs, such as production (costs to ensure sufficient gas supplies), distribution and customer costs. Storage and transmission costs are related to the gas supply (production) function. After separating costs into functions, costs within each function are classified according to services provided to customers, such as the capacity to meet demand (demand-related), the flow of natural gas (energy-related) and access to

the distribution system (customer-related). Classified costs are multiplied by the units of each service provided (annual dkt, peak day demand, number of customers) in order to allocate those costs to various customer classes. Total marginal costs equal the sum of all the allocated costs. Because total marginal costs rarely equal the approved revenue requirement, a final step reconciles total marginal costs and the revenue requirement. A uniform percent adjustment is the reconciliation method used most often, although there are other methods. If unacceptable rate changes result, the reconciled revenue increases may be moderated on public policy grounds. Prices must ultimately be set to recover the allowed revenue requirement.

Table 2

Gas Cost of Service Model (ARM 38.5.176)

Cost Function (1)	**Cost Classification (2)**	**Cost Allocation (3)**	**Reconcile and Moderate (4)**	**Rate Design (5)**
Gas production, storage and transmission	Energy, Demand	Annual throughput, Peak day	Uniform percent or other – e.g., market based	$/dkt
Non-gas distribution	Energy, Demand	Annual throughput, Peak day		
Non-gas customer	Customer	Customer classes		$/month/ customer

MDU Testimony on Cost of Service

MDU's Embedded Cost Study

61. Although the Commission has preferred to use marginal costs to set rates, both MDU witness, Tamie Aberle, and MCC witness, George Donkin, focused heavily on embedded costs. Therefore, the Commission briefly summarizes the respective embedded cost positions of the parties.

62. MDU used its embedded cost of service analysis as a guide for allocating total revenue requirements among customers and for setting rate components for each customer class. The goal of Ms. Aberle's rate design proposals was to move each class's individual rate of return closer to the overall rate of return, based on the results of the embedded cost of service analysis. Ms. Aberle's embedded cost of service study indicated that MDU's test year rate of return, adjusted for known and measurable changes, was 6.695%. The study also indicated that the

small and large interruptible customer classes contribute significantly more to the overall return than the residential and firm general service customers. For this reason, Ms. Aberle allocated responsibility for recovering the proposed revenue increase entirely to the residential and firm general service customer classes. Table 3 shows the results of Ms. Aberle's embedded cost of service study, based on information contained in Statement L, Schedule L-1 of MDU's application.

Table 3

MDU's Embedded Cost Model

Cost function	Classification	Allocation		Per unit cost
Distribution $5,367,678	Commodity (energy) $1,620,733	Residential	$905,550	$0.146/dkt
		Firm General Service	$577,253	$0.162/dkt
		Small Interruptible	$68,307	$0.069/dkt
		Large Interruptible	$69,623	$0.017/dkt
	Capacity (demand) $3,746,945	Residential	$2,145,094	$0.347/dkt
		Firm General Service	$1,227,590	$0.345/dkt
		Small Interruptible	$103,224	$0.104/dkt
		Large Interruptible	$271,037	$0.068/dkt
Customer $15,755,918	Customer	Residential	$11,646,923	$14.979/cust/mo
		Firm General Service	$3,851,144	$40.333/cust/mo
		Small Interruptible	$177,913	$361.612/cust/mo
		Large Interruptible	$79,938	$1,332.300/cust/mo
Total (non-gas) $21,123,596				

63. Table 4 shows the total class revenue requirements that resulted from Ms. Aberle's embedded cost study, compared to current revenues.

Table 4

Calculated Embedded Costs vs. Current Revenues

Customer Class	Non-gas embedded costs	Gas costs	Total embedded cost	Pro forma 2004 revenue	Percent differ-ence
Residential	$14,697,567	$40,414,231	$55,111,798	$52,329,434	-5.32%
Firm Gen. Service	$5,655,987	$23,217,561	$28,873,548	$29,276,679	1.40%
Small Interruptible	$349,444	$452,897	$802,341	$1,214,691	51.39%
Large Interruptible	$420,598	0	$420,598	$537,475	27.79%
Total	$21,123,596	$64,084,689	$85,208,285	$83,358,279	2.22%

64. Table 5 shows the rates of return for individual customer classes based on test year data, along with the rates of return that would result from Ms. Aberle's proposed rate adjustments. This information was provided in Statement M of MDU's application.

Table 5

Accounting-based Rate of Return Comparison

Customer class	Test year return	Revenue increase	Proposed return
Residential	1.40%	$969,986	4.69%
Firm General Service	13.61%	$542,676	17.52%
Small Interruptible	62.38%	0	62.38%
Large Interruptible	21.95%	0	21.95%

MDU's Marginal Cost Study

65. On May 26, 2004, Ms. Aberle submitted supplemental testimony presenting the results of a marginal cost of service study. Ms. Aberle stated that the costing methodology she used was the same methodology used in previous marginal cost studies filed by MDU.

66. Ms. Aberle's cost study included three cost components (functions): 1) marginal gas costs, 2) marginal distribution demand costs and 3) marginal customer costs. She stated that marginal gas costs reflect the long-run cost of gas, including pipeline-related charges. She used Statement G, p. 3 of MDU's application as the source of her marginal gas costs. Statement G showed per books test year gas supply expenses and a pro forma adjustment to test year expenses. According to Statement G, the cost of gas is $6.483 per dkt for residential and firm general service customers and $5.434 per dkt for interruptible customers. Ms. Aberle adjusted these costs upwards to account for distribution losses. Her total marginal cost of gas supply, in 2004 dollars, is $6.53 per dkt for firm sales customers and $5.473 per dkt for interruptible sales customers. She emphasized that gas costs are recovered in commodity rates that are adjusted monthly according to a gas cost tracking adjustment mechanism and that MDU did not request changes to gas supply rates as part of this proceeding.

67. Ms. Aberle classified marginal distribution costs as either capacity (demand)-related, or customer-related. She determined that the marginal demand-related distribution cost is $10.65 per peak day dkt based on the cost of incremental investments in distribution mains and related facilities required to provide an additional dkt of distribution capacity on a peak day. She assembled actual and projected investments related to distribution projects designed to increase

the overall capacity of the system for a 10 year period, 1999 through 2008. The sum of investments for the period, restated in 2006 dollars, divided by the total incremental capacity provided by the investments yields $52.33 per peak day dkt for incremental peak day distribution capacity. Ms. Aberle increased this cost to include an allocation of general and common plant and then applied a nominal carrying charge of 12.34% to derive an annual, levelized cost of $8.08 per peak day dkt. She then adjusted this cost to reflect demand-related operation and maintenance expenses, administrative and general expenses, taxes other than income taxes and working capital. The calculations were provided in her Exhibit TAA-3, pages 4 and 5.

68. Ms. Aberle allocated incremental demand-related distribution costs to residential and firm general service customer classes based on their respective shares of coincident peak day demand. According to an MDU data response (DR PSC-031), the coincident peak day demand is not a weather normalized demand, but is based on the actual peak during the test year. For the small and large interruptible customer classes, Ms. Aberle restated the incremental demand-related distribution cost as a cost per dkt of $0.029 by assuming a 100% load factor for these customers. In the data response (Id), she said that this assumption recognized that interruptible customers do not contribute to the peak day demand costs, but they do place a demand on the system. The resulting cost was allocated to these customers based on annual throughput.

69. Ms. Aberle's calculation of incremental customer-related distribution costs is similar to her calculation of demand-related costs. First, for each customer class she assembled current costs for the capital equipment necessary to connect a new customer to the system: a main extension, service line, meter and regulator. She restated these costs in 2006 dollars. Each of these costs for each customer class was increased to include a share of general and common plant costs and annualized. Then she added customer-related operation and maintenance expenses, administrative and general expenses, taxes other than income taxes and a working capital component. Her customer-related marginal distribution costs are shown in Table 6. The calculations were provided in her Exhibit TAA-3, pages 6 – 10.

70. Ms. Aberle stated that the O&M expenses, A&G expenses, taxes other than income taxes and working capital amounts that were added to the demand- and customer-related marginal distribution costs reflect a five-year average of embedded costs for the period from 1999 through 2003, restated in January 2006 dollars.

Table 6

MDU's Marginal Customer-related Cost Calculations

	Residential	Firm General	Sm. Interrup.	Lg Interrupt.
Capital investment	$1,016.32	$2,377.89	$7,112.82	$22,478.93
General and Common	$255.50	$597.80	$1,788.16	$5,651.20
Total incremental investment	$1,271.82	$2,975.69	$8,900.98	$28,130.13
Annualized cost	$161.23	$375.44	$1,116.34	$3,538.29
O&M, A&G, Taxes, Working Capital	$144.47	$334.90	$1,024.16	$8,572.06
Total annual incremental customer cost	$305.70	$710.34	$2,140.50	$12,152.73
Total cost per month	$25.48	$59.20	$178.38	$1,012.73

71. The total annual marginal cost revenues for the Montana gas operations are $90,519,939, according the results of Ms. Aberle's study. She calculated a uniform adjustment factor to reconcile the total marginal cost revenues with MDU's proposed total revenue requirement in this case, which, according to Ms. Aberle's worksheets, is $85,208,290. She applied the adjustment factor to the individual class marginal costs to establish reconciled marginal cost revenues by rate class. Table 7 compares class revenues at current rates with Ms. Aberle's marginal cost revenues.

Table 7

MDU's Marginal Cost-based Class Revenue Compariosn

Customer class	Current revenues	Reconciled marginal cost revenues	difference	percent differ-ence
Residential	$52,561,881	$57,141,151	$4,579,270	8.71%
Firm General Service	$29,369,158	$27,432,729	-$1,936,429	-6.59%
Small Interruptible	$1,220,178	$529,836	-$690,342	-56.58%
Large Interruptible	$544,410	$104,574	-$439,836	-80.79%
Total	$83,695,627	$85,208,290	$1,512,663	1.81%

72. Ms. Aberle stated that both the embedded cost of service study and the marginal cost of service study indicated that more than MDU's requested revenue increase of $1,513,048 should be allocated to the residential customer class and other customer classes' rates should be decreased.

MDU's Proposed Rate Design

73. In order to recover MDU's requested revenue increase, Ms. Aberle proposed increasing the monthly Basic Service Charges for the residential and firm general service customer classes. Specifically, she proposed a residential Basic Service Charge of $0.23 per day, which is roughly equivalent to a monthly charge of $6.99 and an increase of $0.74 per month from the current rate. She proposed a firm general service Basic Service Charge of $0.40 per day for customers with meters rated less than 500 cubic feet per hour and $0.80 per day for customers with meters rated 500 cubic feet per hour or more. These daily charges are roughly equivalent to $12.16 per month and $24.32 per month, respectively, an increase of $2.16 per month for customers with meters rated less that 500 cubic feet per hour and an increase of $3.07 per month for customers with meters rated 500 cubic feet per hour or greater.

74. Ms. Aberle proposed recovering the rest of the revenue increase, after accounting for revenues from the higher Basic Service Charges, from distribution delivery charges. For residential customers, the distribution delivery rate would increase from the current $1.14 per dkt to $1.203 per dkt. For firm general service customers the distribution delivery rate would increase from $1.367 per dkt to $1.456 per dkt.

75. For an average residential customer using 110 dkt per year, Ms. Aberle's proposed rate adjustments would result in an annul bill increase of $15.82, or an average of $1.32 per month. An average firm general service customer with a meter rated less than 500 cubic feet per hour would see an annual bill increase of $52.62. An average firm general service customer with a meter rated at 500 cubic feet per hour or greater would see an annual bill increase of $116.93. Attachment A to this order illustrates MDU's proposed rate design and compares: 1) MDU's current rate design, 2) MCC's proposed rate design, and 3) the stipulated rate design approved by the Commission.

76. Ms. Aberle also proposed a Distribution Delivery Stabilization Mechanism (DDSM) as a way to adjust customer bills to reflect normal weather. The DDSM would correct for over/under collection of distribution delivery charge revenues due to weather variation during the heating season (Nov. 1 through Mar. 31). She stated that a DDSM would be determined for each rate class and expressed as a rate per dkt. Monthly bills beginning in May of each year would be

adjusted to recover/refund any under/over collection of distribution delivery revenue in the prior heating season.

Montana Consumer Counsel Testimony

77. George Donkin testified for MCC on cost of service and rate design issues. He stated that, in general, gas utility rates should be structured and designed to promote multiple objectives: 1) conservation of energy supplied by gas utilities, 2) economically efficient use of facilities and resources, 3) equity in rates charged to customers, 4) revenue and earnings stability, i.e., utilities should have a reasonable opportunity to recover allowed costs of service, 5) adequate incentives to control costs, 6) rate continuity, i.e., moderate rate changes are preferred to dramatic changes, and 7) understandability and customer acceptance.

78. Mr. Donkin acknowledged that several of these objectives are often in conflict. Lower monthly customer charges and higher commodity rates might better promote conservation and economically efficient consumption, but might also subject the utility to less stable revenue and earnings. Higher monthly customer charges would stabilize utility revenues, but are often unacceptable to customers and diminish the utility's incentives to control costs. According to Mr. Donkin, regulators normally seek a reasonable balance among the various objectives.

79. According to Mr. Donkin, basing gas utility rates on cost of service sends customers the right price signals and leads to efficient allocation of natural gas resources, but there is not a widely accepted method for preparing cost of service studies. Methods vary among gas utilities and regulatory jurisdictions, and evolve as conditions in the industry change over time. Most methods, according to Mr. Donkin, have some common traits, such as distinguishing between variable costs and fixed costs. He said variable costs are almost always allocated among customers on the basis of their respective annual usage. Fixed costs, which mostly relate to the capacity to deliver gas, can be allocated in a number of different ways, he said. Common factors used to allocate fixed costs are: 1) peak period or peak day usage levels, 2) seasonal usage levels, 3) annual usage levels, and 4) number of customers. Often a combination of the above factors is used.

80. Mr. Donkin described marginal cost of service as the cost of providing one more or one less unit of natural gas, either on a peak day or on an annual basis. Marginal costs vary according to the time frame being considered. Short-run marginal costs reflect the cost of

producing an incremental amount of service holding constant elements of the current physical system such as distribution plant and contracts with pipeline suppliers. The costs of these elements are often fixed in the short-run and, therefore, are not included in short-run marginal costs.

81. Long-run marginal costs do not consist of fixed costs because all inputs to production and delivery are variable in the long run. According to Mr. Donkin, utility rates should not reflect long-run marginal costs since it would take many years to restructure gas supply arrangements and reconstruct physical plant in order to minimize costs in response to small changes in output. He said gas supply arrangements and physical plant are largely fixed and are difficult to change in response to changes in demand, so utility rates usually reflect a form of intermediate-run marginal costs, which include costs associated with existing capacity. Exhibit MCC 3, p. 6.

82. Mr. Donkin explained that embedded cost of service reflects a calculation of a gas utility's historic costs, including costs used to support the allowed revenue requirement. Embedded costs are allocated to customer classes based on historic cost responsibility. He asserted that gas utility service is largely the provision of joint products and embedded cost of service studies attempt to allocate joint costs among rate classes. He said most natural gas utilities and regulatory commissions use embedded cost studies in the ratemaking process, while marginal costs receive more attention when there is a large difference between marginal and embedded costs, as occurred in the early 1980s when market prices of natural gas supplies greatly exceeded the price of regulated gas supplies. Today there is little difference between the marginal and embedded cost of gas supply and short- and intermediate-run non-gas marginal costs are far below embedded costs. As a result, he does not believe basing cost allocation and rate design on short-run marginal costs would promote economically efficient gas consumption decisions or equity in the recovery of non-gas costs. Exhibit MCC 3, p. 8.

Marginal Cost of Service

83. Mr. Donkin did not provide an independent marginal cost of service study. However, he testified that MDU's study did not reflect traditional marginal cost analysis and should not be used to evaluate the reasonableness of MDU's non-gas class revenues and rate design proposals. According to Mr. Donkin, traditional gas utility marginal cost analyses focus on the change in

total costs of increasing gas sendout by incremental amounts. Incremental output could be related to increased consumption by existing customers or from new customers. He said MDU, which experiences very little customer growth, should focus on the marginal cost of peak- and off-peak distribution capacity and argued that Ms. Aberle's study focused on marginal customer costs and provided little information about how MDU's non-gas costs increase or decrease as customers increase or decrease their consumption of natural gas. He maintained that 96.9% of Ms. Aberle's total non-gas marginal costs were classified as customer costs and 97.7% of residential class non-gas marginal costs were classified as customer costs. He said these results lead to the implausible conclusion that off-peak conservation or an increase in off-peak consumption would have zero impact on MDU's total non-gas cost of service. He also concluded that under Ms. Aberle's cost study adding new customers to MDU's system adds more costs than revenues. He believes Ms. Aberle's cost study overestimated the actual cost of adding a new residential customer and, therefore, her marginal cost study has no value for evaluating the reasonableness of non-gas revenue responsibility on the MDU system.

84. Mr. Donkin asserted that marginal gas costs are not relevant to this proceeding because MDU recovers gas supply costs through a tracker. Nonetheless, he testified that MDU's marginal gas cost consists of the cost of acquiring gas supply from gas producers or marketers, including variable transport costs. He said MDU's marginal gas cost should not include demand or reservation charges paid to its pipeline supplier, Williston Basin Interstate Pipeline (WBIP), since MDU cannot avoid paying these charges under long-term service agreements. In other words, pipeline demand and reservation charges are fixed in the short-term. And, he said, even in the long-term MDU has a limited ability to avoid these charges because MDU represents such a large percentage of WBIP's firm demand. Any reduction in MDU's firm contract capacity would likely result in a corresponding increase in the charges MDU pays WBIP. Exhibit MCC 3, p. 10. While noting that MDU's marginal gas cost fluctuates widely over time, he estimated that the summer 2004 cost ranged between $5.50 and $6.00 per dkt. Id., p. 11.

Embedded Cost of Service

85. Mr. Donkin also disagreed with MDU's embedded cost study. He said Ms. Aberle's study allocated most non-gas costs based on the number of customers and peak period volumes. Statement L, Schedule L-1 of the Company's application showed that Ms. Aberle's embedded

cost study classified 74.6% of total non-gas costs as customer related, 17.7% as demand related and 7.7% energy related. According to Mr. Donkin, Ms. Aberle's method assigns an excessive amount of non-gas costs to small volume customers in the firm rate classes, and too little to interruptible customers.

86. According to Mr. Donkin, MDU classified 30 percent of distribution mains costs as customer-related and 70 percent demand-related, but none of these costs should be classified as customer-related. Distribution mains are part of the integrated delivery system that provides energy supply throughout the year and during peak periods. He maintained that the load, not the number of customers, drives the utility's investment in distribution plant. He recommended classifying 50 percent of distribution mains cost as demand-related and allocating those costs to customer classes based on coincident peak day demands at distribution. He would classify the other 50 percent of distribution mains costs as energy-related and allocate them to customer classes based on annual throughput at distribution. He reasoned that even if customer demand did not vary over the course of a year, the capacity of the distribution system would still have to be designed to meet a peak-day demand of 33,130 dkt. Therefore, some distribution costs are related to average annual usage and some are related to peak period deliveries, which, he said, supports classifying 50 percent of these costs as energy-related. Additionally, he said, many of the costs of gas distribution mains do not vary according to pipe capacity, for example excavation costs, rights-of-way costs, inspection costs, surveying costs and the costs of replacing sidewalks and roads, so total costs do not increase by a one-to-one ratio as peak demand increases.

87. Mr. Donkin disagreed with Ms. Aberle that 100 percent of distribution service line costs should be classified as customer-related since this approach does not recognize that the primary function of a service line is to move gas volumes from the distribution main to the point of consumption. He recommended classifying 50 percent of the total investment in service lines as customer-related and 50 percent demand-related. He recommended allocating the demand-related portion on the basis of coincident peak day demand at distribution.

88. Mr. Donkin recommended allocating administrative and general expenses 50 percent on the basis of coincident peak day demand and 50 percent on the basis of total throughput. He also used this method to allocate several other components of MDU's total embedded costs, including investments in general plant and common plant, other taxes and gas in underground

storage component of working capital. He said he allocated uncollectible accounts and sales expenses on the basis of class revenues, rather than the number of customers in each rate class. The rates of return for each customer class that result from Mr. Donkin's recommendations compared to MDU's embedded cost study are provided in Table 8.

Table 8

Accounting Rates of Return: MCC vs. MDU

	MCC	MDU
Overall	6.695%	6.695%
Residential	8.650%	1.401%
Firm General Service	11.015%	13.607%
Small Interruptible	62.381%	13.816%
Large Interruptible	-17.769%	21.946%

89. According to Mr. Donkin, with appropriate changes Ms. Aberle's embedded cost of service study would show that existing rates of return for MDU's customer classes are reasonably in line with each other, except for the Large Interruptible class, which is producing a significant negative rate of return at current rate levels. Accordingly, he asserted that MDU's proposal to increase non-gas revenue while holding constant the non-gas revenue responsibility of its interruptible customer classes is unjust, unreasonable and should be rejected. He said non-gas revenue responsibility should be shifted to large interruptible customers, who at current rates, contribute $537,475, about 2.8%, to MDU's total non-gas costs but account for 27.2% of total Montana annual throughput. Mr. Donkin's proposed class revenues are shown in Table 9.

Table 9

MCC's Proposed Non-gas Revenues

Customer class	Current non-gas cost revenues	MCC proposed non-gas cost revenues	Increase/decrease	% change
Residential	$11,915,303	$11,463,129	($452,174)	-3.795%
Firm General Service	$6,059,173	$5,829,233	($229,940)	-3.795%
Small Interruptible	$761,828	$732,917	($28,911)	-3.795%
Large Interruptible	$537,475	$1,000,242	$436,414	86.1%

90. Mr. Donkin's class revenues were based on MCC's proposed total non-gas revenue requirement of about $19 million, presented by MCC's witness, Clark. Mr. Donkin developed his class revenues by first charging the large interruptible customer class $0.25 per dkt for test year throughput of 4,000,969 dkt. This produced $1,000,242. Next, he reduced the revenues of the other customer classes by an equal percent necessary to arrive at the proposed non-gas revenue requirement. He noted that even though his proposal would increase large industrial class revenues by 86%, that class' rate of return would still be -9.3%.

91. He acknowledged that several large interruptible customers may have bypass opportunities if their rates are raised too much. He therefore proposed a margin sharing/flexible pricing alternative for apportioning non-gas revenue responsibility. Under this approach, rates for the large industrial class would be set at MDU's proposed amount but MDU would be allowed to price the service on a competitive basis subject to a price cap. MDU could keep 20% of large interruptible non-gas revenue in excess of $537,475. He said this approach should give MDU an incentive to price large interruptible service at higher levels than it has proposed in this case, but not so high that customers would bypass the system.

MCC's Proposed Rate Design

92. Mr. Donkin recommended that the Commission reject MDU's proposal to increase monthly customer charges asserting that, based on variable embedded costs, a residential monthly charge of $6.25 or less would be appropriate. A higher monthly charge would cause existing residential customers to pay too much for the customer component of their rate and too little for the commodity cost of gas service.

93. He also recommended that the Commission reject MDU's proposal for a distribution delivery stabilization mechanism (DDSM) for two reasons: first, such weather normalization mechanisms distort price signals by increasing or decreasing rates in subsequent periods relative to actual costs, and second they reduce a utility's business risk relative to the risk used to calculate the utility's cost of capital. He also noted that MDU's proposed DDSM would conflict with Commission policy as reflected in Order No. 4914a.

MDU Rebuttal Testimony

Marginal Costs

94. Ms. Aberle disagreed with Mr. Donkin's characterization of her marginal cost study. She said Mr. Donkin's criticism that her study did not focus on the change in total costs from increasing or decreasing gas sendout failed to recognize the system-related costs associated with adding new customers.

95. She also disagreed with Mr. Donkin's conclusion that her study overstated the marginal cost of customer growth. She said Mr. Donkin appeared to reach his conclusion based on a comparison of the average marginal distribution cost per customer and the average annual distribution revenues collected from the residential class under proposed rates. She said Mr. Donkin inappropriately compared embedded revenue requirements and average marginal costs. She identified several adjustments to the marginal cost calculation that could be made to make a comparison to embedded costs appropriate. She also pointed out that MDU's line extension policy requires contributions from new customers if rates would not recover the incremental investment.

Embedded Costs

96. Ms. Aberle disagreed with Mr. Donkin that none of the embedded distribution mains investment should be classified as customer-related. She maintained that classifying a portion of the distribution mains cost as customer-related is a standard practice throughout the gas industry. She referenced a 1989 Gas Distribution Rate Manual prepared by the NARUC staff subcommittee on gas rates which found that a portion of distribution system capital costs can be classified as customer related because there is a minimum size main necessary to connect a customer to the system which affords the customer an opportunity to take service. She also disagreed with Mr. Donkin that a portion of distribution mains costs should be classified as energy-related, maintaining that mains investment does not vary as more or less gas is used. She said the fact that customers exist and require a system to deliver natural gas on demand on the coldest day of the year supports classifying and allocating embedded distribution costs on the basis of customers and peak day demand.

97. Ms. Aberle also disagreed with Mr. Donkin's recommendation to classify service lines investment 50 percent customer-related and 50 percent demand-related. She said service lines are clearly customer-related since investment varies directly with the number of customers

served not the amount of utility service provided. She also said the NARUC gas distribution rate design manual discussed above supports classifying service lines investment as customer-related.

98. Ms. Aberle rejected Mr. Donkin's recommendation to allocate administrative and general expenses 50 percent based on coincident peak day demands and 50 percent on annual throughput. She stated that administrative and general expenses are incurred for overall support of all other functions and that is why they should be allocated on the basis of other operation and maintenance expenses. Again, Ms. Aberle said the NARUC manual supports MDU's approach.

99. According to Ms. Aberle, Mr. Donkin's recommendation to use the 50 percent demand-50 percent throughput allocator for general and common plant, ad valorem taxes, other taxes and gas in underground storage does not follow the principle of cost causation. General and common plant consists of such things as office buildings, furniture, computer equipment and transportation equipment. She maintained that general and common plant supports the distribution function and the allocation of the costs of these investments should reflect that.

Rate Design

100. Ms. Aberle criticized Mr. Donkin's proposed rate design, asserting that he provided no basis for his $0.25 per dkt rate, which was used to assign revenues to the large interruptible customer class. She also said increasing non-gas rates for the large interruptible class would jeopardize MDU's ability to fully realize the increased revenues (presumably due to the risk of bypass). She maintained that the large increase proposed by Donkin contradicts several of the rate design objectives he subscribed to including equity, revenue and earnings stability, rate continuity, understandability and customer acceptance.

101. Ms. Aberle dismissed Mr. Donkin's proposed margin sharing/flexible pricing proposal saying his embedded cost conclusions are wrong, and incentives exist today to price large interruptible service at the highest available price to minimize revenue erosion. She asserted that Mr. Donkin incorrectly thinks that MDU has proposed new rate levels for the large interruptible class, when, in fact, revenues for this class reflect contracts what were executed before this rate case was filed. She said the average per unit revenue from this class has ranged from a low of $0.129 per dkt to a high of $0.140 per dkt during the period 1999-2003. The average over that time period was $0.132 per dkt.

102. Ms. Aberle said Mr. Donkin's calculation of cost-based customer charges based on variable monthly embedded customer costs is inappropriate and unsound because classifying customer costs as variable is inconsistent with the theory that customer costs are fixed. She said Mr. Donkin's own embedded cost study supports a monthly charge of about $7.50 for the residential class.

103. Finally, Ms. Aberle clarified that MDU's proposed distribution delivery stabilization mechanism would only apply to the distribution component of bills. This component represents about 22% of a customer's total annual bill. Therefore, Ms. Aberle concluded the DDSM would not distort price signals. She also disagreed that the Commission's Order 4914a, referenced by Mr. Donkin, established a policy that would preclude the proposed DDSM or a similar mechanism.

PSC Cost of Service Analysis and Decisions

104. The Commission's long-standing policy is to set utility rates based on economic costs, meaning marginal, avoidable or incremental costs. Marginal cost is the increase/decrease in the total cost of production that results from increasing/decreasing the rate of production by one unit. Mathematically, it is the slope of the total cost curve at a specific level of output. The decrease in total cost associated with a decrease in production is also referred to as the avoided cost. In its first order addressing a comprehensive marginal cost study by a natural gas utility, the Commission stated that marginal cost pricing facilitates efficient resource allocation.[1] The Commission's policy was embraced by, among others, Montana Power Company (MPC) and MCC. MCC noted that using marginal costs promotes rate structures that encourage conservation, efficiency and equity. Since its first order on marginal cost pricing the Commission has established administrative rules requiring utilities to file an analysis of marginal costs to support rate design proposals. Of course, marginal cost estimates are not the only determinant of Commission-approved rates. First, prices must recover the allowed revenue requirement, which is based on accounting costs that may be more or less than marginal costs. A range of public policy considerations also typically informs Commission pricing decisions.

105. The evidentiary record on marginal costs in this proceeding consists of MDU's analysis and Mr. Donkin's relatively cursory critique, along with discovery and late filed exhibits

[1] See Montana Power Company docket no. 87.8.38, order no. 5410, paragraph 106.

that clarify and, in some cases, expand on MDU's analysis. Additionally, the Commission may take administrative notice of the body of prior Commission orders regarding natural gas utility marginal costing and pricing issues. Consistent with the Commission's well-grounded, established policy to base pricing decisions on analyses of marginal costs, this order analyzes the marginal cost information in this proceeding, referring to prior Commission orders where relevant. Using the marginal cost model described above, the Commission first analyzes the record with regard to marginal costs for gas supply, distribution and customer cost functions. The Commission assesses the MDU-MCC Stipulation in light of its marginal cost findings.

106. In this docket, Mr. Donkin articulated a number of pricing principles that are consistent with marginal cost-based prices including conservation, efficient use of facilities and resources and equity. He also identified a number of pricing principles that are public policy-related, such as understandability, customer acceptance and continuity. However, in contrast to previous MDU gas dockets, Mr. Donkin did not perform an in-depth, independent marginal cost analysis. Instead, after analyzing MDU's approach to estimating marginal costs, he concluded the approach was flawed and he developed an alternative embedded cost analysis. Mr. Donkin reasoned that marginal cost analysis is more relevant to utility ratemaking when there is a significant difference between marginal and embedded costs, for example when the marginal cost of gas supply greatly exceeds the average cost. In Mr. Donkin's view, since gas supply prices are now determined by market forces and a local distribution utility's non-gas marginal costs in the short- and intermediate-run are far below embedded costs, basing rates on marginal costs will not likely promote efficient consumption or equity in the recovery of non-gas costs.

Marginal Gas Supply Costs

107. In Order 5856b, docket D95.7.90, the Commission criticized both MDU and MCC for not analyzing gas costs more thoroughly. The Commission rejected proposals to rebalance rates finding that it would not serve the public interest to rebalance based on non-gas costs when the majority of MDU's costs are gas-related.[2] The Commission found that marginal gas costs must be part of cost of service for rate design.[3] In this case, while both MDU and MCC discuss gas supply costs briefly, neither party provided the kind of thorough analysis the Commission

[2] Docket No. D95.7.90, Order No. 5856b, paragraph 189.
[3] Id. paragraph 191.

determined was necessary in order 5856b. The Commission will require MDU to analyze marginal gas costs in future proceedings for non-gas rate design purposes.

108. MDU's marginal gas cost was derived from embedded costs and adjusted to reflect pro forma 2004 information. Ms. Aberle stated that MDU used this approach because gas costs are not an issue in this proceeding. TR 32. Ms. Aberle estimated marginal gas costs of $6.53 per dkt and $5.473 per dkt for firm and interruptible customers, respectively, including line losses.

109. In prefiled testimony, Mr. Donkin asserted that marginal gas costs are not relevant in this proceeding because MDU recovers these costs through a gas cost tracking mechanism. However, at the hearing, Mr. Donkin stated that marginal gas costs could be relevant to non-gas cost allocation and rate design. TR 76-78. Mr. Donkin stated that MDU's marginal gas cost consists of the cost of acquiring gas supply from producers or marketers, including variable transportation costs. Because MDU pays its pipeline supplier demand and/or reservation charges pursuant to long-term service agreements, Mr. Donkin determined that these charges are not avoidable and should not be included in marginal gas supply costs. Storage costs are avoidable, in Mr. Donkin's view. TR 65. Mr. Donkin estimated the marginal cost of gas supply at between $5.50 per Dkt and $6.00 per dkt in summer 2004.

110. Table 10 illustrates the relevance of marginal gas costs to cost allocation and rate design. The allocation of costs to customer classes, reconciled to the revenue requirement, varies depending on the chosen marginal cost of gas supply, holding other cost components equal. Although in this case the differences appear relatively small, some general service customers, for example, could pay hundreds of dollars more per year with MDU's gas cost estimate compared to MCC's. Information on the marginal cost of gas can also be relevant to deciding whether to recover non-gas costs through monthly Basic Service Charges or per dkt charges.

Table 10

Marginal cost revenues reconciled to revenue requirement

	Residential	Firm General Service	Sm. and Lg Interruptible	Revenue Requirement
MDU gas cost estimate	$57,141,151	$27,432,729	$634,410	$85,208,290
MCC low gas cost estimate	$57,497,827	$26,994,585	$715,878	$85,208,290

111. Neither MDU nor MCC provided thorough economic analyses to support their marginal gas cost estimates, in spite of the Commission's findings in Order 5856b. To the extent MDU's and MCC's marginal gas cost estimates are forward looking, both appear to be short-run; Mr. Donkin's estimate is based on summer 2004 and MDU's is perhaps based on 2004 as a whole. The record is essentially void of information on the appropriate basis for MDU's marginal gas supply costs. At the hearing, the Commission requested that MDU provide a copy of its annual 10-year projection of gas rates as a late-filed exhibit. The 10-year projection, dated February 2004, shows MDU's estimates of nominal gas costs for the period 2004 through 2013. If these projected nominal gas costs are converted to 2006 dollars using MDU's expected inflation rate of 2.05%, the exhibit shows declining real costs that average $5.51 per dkt.[4] Superficially, MCC's marginal gas cost estimate appears to better reflect forward looking gas costs. However, the analysis underlying MDU's 10-year projection was not evaluated in this proceeding. For example, notes accompanying MDU's projection indicate that the gas costs include costs for delivery to town border stations, i.e., they include costs related transporting purchased gas to MDU's distribution system. MDU's transportation and storage costs derive from contracts with Williston Basin Interstate Pipeline executed pursuant to Federal Energy Regulatory Commission tariffs. The record contains some information on these pipeline charges but not enough to definitively determine whether they represent incremental or avoidable costs. Again, Mr. Donkin argued that transportation costs are not avoidable because they are fixed in long-term contracts. If Mr. Donkin is correct, both MDU's projections, and Mr. Donkin's short-run cost estimates may overstate longer-term marginal gas costs. For purposes of its analysis, the Commission uses $5.50 per dkt. In future proceedings, MDU must more thoroughly evaluate forward-looking gas costs as part of its marginal cost studies. Included in the evaluation must be a thorough analysis of how Williston Basin Interstate Pipeline-related transportation costs are incurred and how those costs are allocated to rate classes. Alternatively, as previously suggested by the Commission, an annual gas tracker case could also be an appropriate forum for evaluating gas cost of service and rate design issues, including the sources of transportation costs and the proper allocation of those costs.[5]

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[4] MDU's calculation of real carrying charges assumes an inflation rate of 2.05%. See late filed exhibit 2, p. 10.
[5] Docket No. D95.7.90, Order 5856b, paragraph 232.

Marginal Distribution Costs

112. MDU estimated marginal distribution capacity-related costs using a method that is similar to the one it used in docket D95.7.90. Ms. Aberle used costs associated with a combination of historic and projected capacity expansion projects to derive a cost for incremental peak day distribution capacity. She screened project costs to eliminate any costs associated with pipe less than 2 inches in diameter as a means of removing costs that might be associated with service lines, which she considers customer-specific costs. DR PSC-027 and PSC-037. Using actual costs for 1999-2003 and projected costs for 2004-2008, Ms. Aberle determined that incremental distribution capacity-related costs are $10.65 per peak day dkt.

113. Mr. Donkin's critique of MDU's marginal cost analysis was not specific to individual, non-gas cost functions. Mr. Donkin asserted that Ms. Aberle's non-gas marginal cost analysis focused primarily on costs related to adding new customers, instead of properly focusing on costs related to changes in demand by existing customers. In docket D95.7.90 Mr. Donkin used a method similar to MDU's method in this case, except Mr. Donkin relied on actual recently completed distribution capacity projects. DR PSC-037. In that case, the Commission found that the difference between the marginal distribution costs estimated by MDU and MCC was due to Mr. Donkin's use of actual recent distribution investment experience.[6] While commending MDU for using a forward-looking approach, the Commission ultimately adopted Mr. Donkin's method finding it similar to the analysis approved in Docket 88.11.53.[7]

114. The Commission finds that its previously adopted method remains reasonable. Applying this method to the actual recent distribution capital investments identified in Ms. Aberle's marginal cost analysis (1999 – 2003) results in a marginal capacity-related distribution cost of $7.88 per peak day dkt. In the absence of a specific alternative marginal cost analysis from MCC, the Commission finds that this is a reasonable adjustment to MDU's marginal cost analysis.

Marginal Customer Costs

115. Ms. Aberle's calculation of marginal customer-related costs is similar to her calculation of marginal capacity-related distribution costs. First, for each customer class she

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[6] Docket D95.7.90, Order 5856b, paragraph 163

[7] Id, paragraph 192.

assembled current costs for the capital equipment necessary to connect a new customer to the system: a main extension, service line, meter and regulator. She restated these costs in 2006 dollars. Each of these costs for each customer class is grossed up for general and common plant costs and annualized. Then she added customer-related operation and maintenance expenses, administrative and general expenses, taxes other than income taxes and a working capital component.

116. Again, Mr. Donkin did not critique Ms. Aberle's non-gas cost analysis by cost function. However, his assertion that Ms. Aberle's analysis inappropriately focuses on the cost of adding new customers rather than the cost of serving existing customers makes the most sense in the context of her method for estimating marginal customer costs, especially given his prior testimony on distribution costs as discussed above. In docket D95.7.90 the Commission approved Mr. Donkin's method for determining the capital costs underlying marginal customer costs. In that case Mr. Donkin excluded investments in main extensions and service lines. This was consistent with long-standing Commission practice. In its first natural gas utility marginal cost of service docket the Commission stated that including meter and regulator costs while excluding costs for main extensions and service lines turns on the concept of opportunity costs.[8] Meters and regulators have opportunity costs in that a customer's decision to continue receiving service prevents the Company from using the meter and regulator to serve another customer. In contrast, once a main extension and service line are in place the investment is a sunk cost with respect to existing customers;[9] MDU could not cost effectively redeploy the main extension and service line if the customer decides to discontinue gas service. The record in this case appears to support the Commission's long-standing approach. In response to a data request, Ms. Aberle acknowledged the fungibility of meters and regulators and agreed that mains and services can not be cost effectively redeployed. DR PSC-027. In the absence of a specific alternative marginal cost analysis from MCC, the Commission finds excluding the capital costs for main extensions and service lines from MDU's marginal cost analysis remains reasonable. A comparison of the resulting marginal customer costs is shown in table 11.

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[8] Docket 87.8.38, Order 5410, paragraph 144.
[9] Id, paragraph 145.

Table 11

Marginal Customer-related Costs ($/month)

	Residential	Firm General	Sm. Interrup.	Lg Interrupt.
MDU estimate	$25.48	$59.20	$178.38	$1,012.73
Exclude main ext., service line	$7.19	$31.59	$150.77	$853.65

Other Marginal Cost Issues

117. In a marginal cost analysis carrying charges typically reflect the total cost of long-lived capital assets converted to a series of annual costs. For example, as discussed above, Aberle's estimate of marginal distribution capacity-related costs started with investments in distribution capacity. The total cost of these investments must be converted into an annual cost that can be allocated to customers. Ms. Aberle uses nominal carrying charges throughout her marginal cost analysis. In docket D95.7.90 the Commission stated that real carrying charges should be used to annualize distribution and customer costs.[10] When asset prices are increasing because of inflation, real carrying charges start at a lower value than nominal carrying charges, but rise from year to year. Consequently, in docket D95.7.90 the Commission found that using nominal carrying charges exaggerates distribution and customer cost estimates relative to using real carrying charges.

118. At the hearing the Commission asked Aberle to estimate marginal distribution and customer costs using real carrying charges. Late Filed Exhibit No. 2 contains the results. In the absence of a specific alternative marginal cost analysis from MCC, the Commission finds that using the real carrying charges in Late Filed Exhibit No. 2 is a reasonable adjustment to Ms. Aberle's marginal cost analysis. The result is slightly lower marginal distribution costs and marginal customer costs.

Summary of Marginal Costs

119. Table 12 compares the marginal costs from Aberle's analysis to the marginal costs that result from the Commission's adjustments described above.

120. Note that MDU's initial marginal cost analysis did not estimate separate marginal customer costs for firm general service customers served by small meters and large meters. The Commission requested a separate cost breakdown at the hearing and MDU provided the

[10] Docket D95.7.90, Order 5856b, paragraph 197.

breakdown in Late Filed Exhibit No. 2. The Commission also notes that while MDU converted the distribution capacity cost into a cost per dkt for interruptible customers, the Commission has previously determined that it is theoretically incorrect to allocate peak day demand costs to interruptible customers.[11]

Table 12

Comparison of Marginal Costs: MDU vs. Commission-adjusted

Marginal Cost Component	Residential	Firm General Service <500 cf/h	Firm General Service 500+ cf/h	Small Interruptible	Large Interruptible
MDU analysis					
Gas supply ($/Dkt)	$6.53	$6.53	$6.53	$5.473	$5.473
Dist. capacity ($/mcfd)	$10.65	$10.65	$10.65	$0.029	$0.029
Customer ($/mo)	$25.48	$59.20	$59.20	$178.38	$1,012.73
MDU analysis w/ adjustments					
Gas supply ($/Dkt)	$5.50	$5.50	$5.50	$5.50	$5.50
Dist. capacity ($/mcfd)	$6.66	$6.66	$6.66	$0.01825	$0.01825
Customer ($/mo)	$6.82	$10.41	$48.53	$136.36	$816.46

Rate Design

121. Using the adjusted marginal costs from Table 12 above, class marginal cost-based revenues are shown in Table 13. Table 13 also shows the class revenues that would result from an equal percent reconciliation to the proposed revenue requirement implied by the stipulation between MDU and MCC.

[11] Docket 87.8.38, Order 5410, paragraph 154.

Table 13

Commission-adjusted Marginal Cost Revenues and Reconciled Revenues

Marginal cost based revenues	Total	Residential	Firm Gen <500 cf/h	Firm Gen 500+ cf/h	Small Interruptible	Large Interruptible
Gas supply	$54,049,842	$34,039,467	$6,320,089	$13,235,239	$455,098	$0
Distribution	$514,083	$297,922	$55,105	$115,398	$13,992	$31,666
Customer	$7,239,728	$5,303,068	$768,258	$1,052,325	$67,089	$48,988
Total	$61,803,703	$39,640,457	$7,143,452	$14,402,962	$536,178	$80,654
Test year revenue*	$83,358,279	$52,329,434	$9,812,498	$19,464,181	$1,214,691	$537,475
Stipulated increase	$124,625					
Proposed revenue	$83,482,904					
Reconciliation factor	1.356233					
Reconciled marginal cost revenues	$83,482,904	$53,545,343	$9,649,197	$19,455,162	$724,256	$108,946
Percent change	0.15%	2.32%	-1.66%	0.05%	-40.38%	-79.73%
Stipulated revenue		$52,407,192	$9,842,018	$19,481,529	$1,214,691	$537,475

* Test year revenues from Statement H, p. 3 and Statement M, p. 1

122. Attachment A to this Order compares MDU's current rates to the rate design stipulated to by MDU and MCC along with the rate designs advocated by each party in prefiled testimony.[12] As shown in the attachment, MDU proposed increases in both basic monthly service charges and per-dkt distribution rates for residential and firm general service customers. MDU's rates were designed to recover approximately $1.5 million of additional revenue annually. MCC advocated a net reduction in MDU's annual revenues of $274,611. Additionally, Mr. Donkin recommended rebalancing class revenue requirements by reducing per-dkt distribution rates for the residential, firm general service and small interruptible classes and increasing the per-dkt distribution rate for the large interruptible class. Mr. Donkin recommended maintaining current basic monthly service charges for all customer classes. The Stipulation slightly increases the basic monthly service charges for the residential and firm general service classes and produces additional annual revenues of $124,625, or about 0.15 percent of test year revenues.

[12] The attachment focuses on the residential and firm general service classes since these are the customer classes covered by the stipulation. MCC initially recommended rate adjustments for interruptible customers.

123. The Commission finds the rate adjustments in the Stipulation to be within a zone of reasonableness when placed in the context of the adjusted marginal costs outlined above. In the past the Commission has preferred to recover some of a rate increase in the commodity (i.e., per-dkt) rate so customers have an opportunity to avoid some of the increase by changing consumption behavior.[13] However, in this case the overall increase is so small that, for all practical purposes, there is no difference in a customer's final bill under various rate design scenarios, as shown in the table at the bottom of Attachment A. Additionally, the adjusted marginal cost analysis indicates that current Basic Service Charges are below marginal costs, while the distribution demand costs, when converted to per-dkt rates, are well below current distribution rates.

124. Finally, as this Order adopts the Stipulation between MDU and MCC, the Commission finds that the various other tariff changes MDU initially proposed related to its operating rules and the distribution delivery stabilization mechanism are moot.

III. CONCLUSIONS OF LAW

125. All findings of fact, discussion, and decisions above that can properly be categorized as consclusions of law and should be so categorized to preserve the integrity of this final order are adopted here as conclusions of law.

126. MDU is a public utility as defined in § 69-3-101, MCA. The PSC has jurisdiction over MDU in regard to the matter presented pursuant to §§ 69-3-102, 69-3-103, 69-3-106, et al., MCA. MDU's application and supplement were properly filed and processed.

ORDER

IT IS HEREBY ORDERED that the above order is the Final Order in this matter, MDU shall comply with the provisions of this Final Order, and MDU shall file tariffs in compliance with this Final Order.

Done and dated this 10th day of May, 2005, by a vote of 4 – 1.

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[13] Docket D95.7.90, Order 5856b, paragraph 235.

	A	B	C	D	E	F	G	H	I	J
1	**Summary of MDU-MCC stipulation in D2004.4.50**									
2									**Attachment A**	
3		**Current rates**		**Stipulated rates**		**MDU testimony**		**MCC testimony**		
4	Rate Schedule	Basic Service Charge	Distribution Delivery Charge	Basic Service Charge	Distribution Delivery Charge	Basic Service Charge	Distribution Delivery Charge	Basic Service Charge	Distribution Delivery Charge	
5	Residential Rate 60	$6.25	$1.14	$6.35	$1.14	$6.99	$1.203	$6.25	$1.067	
6	Firm General Service Rate 70									
7	Meters rated < 500 cf/h	$10.00	$1.37	$10.40	$1.37	$12.16	$1.367	$10.00	$1.302	
8	Meters rated 500+ cf/h	$21.25	$1.37	$22.05	$1.37	$24.32	$1.456	$21.25	$1.302	
9										
10										
11	**Allocation of revenue increase & results of stipulated rate design**									
12	Rate class	Billing units	Dkt	Current Distribution Revenues	Stipulated Distrubution Revenues	Gas commodity expense	Total Current Revenue	Total Stipulated Revenue	Difference	pct
13	Residential Rate 60	777,576	6,188,994	$11,915,303	$11,993,061	$40,414,131	$52,329,434	$52,407,192	$77,758	0.15%
14	Firm General Service Rate 70									
15	Meters rated < 500 cf/h	73,800	1,149,107	$2,308,829	$2,338,349	$7,503,669	$9,812,498	$9,842,018	$29,520	0.30%
16	Meters rated 500+ cf/h	21,684	2,406,407	$3,750,343	$3,767,691	$15,713,838	$19,464,181	$19,481,529	$17,347	0.09%
17	Stipulated revenue increase								$124,625	
18										
19	**Monthly residential bill under various rate designs**									
20		**Current**			**Stipulation**					
21	Basic Service Charge	$6.25	$6.25	$6.30	$6.35					
22	Distribution Delivery Charge	$1.1400	$1.1526	$1.1463	$1.1400					
23	Assumed gas commodity rate	$6.5000	$6.5000	$6.5000	$6.5000					
24	Annual dkt	**Average monthly bill amount**								
25	70	$ 50.82	$ 50.89	$ 50.90	$ 50.92					
26	75	$ 54.00	$ 54.08	$ 54.09	$ 54.10					
27	80	$ 57.18	$ 57.27	$ 57.28	$ 57.28					
28	85	$ 60.37	$ 60.46	$ 60.46	$ 60.47					
29	90	$ 63.55	$ 63.64	$ 63.65	$ 63.65					
30	95	$ 66.73	$ 66.83	$ 66.83	$ 66.83	**Average consumption**				
31	100	$ 69.92	$ 70.02	$ 70.02	$ 70.02					
32	105	$ 73.10	$ 73.21	$ 73.21	$ 73.20					
33	110	$ 76.28	$ 76.40	$ 76.39	$ 76.38					

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

GREG JERGESON, Chairman

BRAD MOLNAR, Vice-Chairman, Voting to Dissent

DOUG MOOD, Commissioner

ROBERT H. RANEY, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Connie Jones
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.

CERTIFICATE OF SERVICE

I hereby certify that a copy of **FINAL ORDER 6580a** issued in D2004.4.50 in the matter of Montana-Dakota Utilities Co. has today been served on all parties listed on the Commission's most recent service list, created 4/23/04, by mailing a copy thereof to each party by first class mail, postage prepaid.

Date: May 12, 2005

Katy Bogy
For The Commission

Intervenors:

Montana Consumer Counsel

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

* * * * *

IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO., Application for Authority to Increase Rates for Natural Gas Services in its Montana Service Areas	))))	**UTILITY DIVISION D2004.4.50** **STIPULATION**

COMES NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota) and the Montana Consumer Counsel (MCC) and agree and stipulate as follows:

1. On April 1, 2004, Montana-Dakota filed with the Commission an Application for authority to implement a general rate increase in the rates it is authorized to charge for natural gas service in Montana. The requested rate increase, if granted in its entirety, would have raised an additional $1.51 million dollars in annual revenues. The Application was denominated PSC Docket D2004.4.50.

2. The MCC intervened in the docket, opposing both the proposed rate increase and the manner in which Montana-Dakota proposed to allocate its revenue deficiency between customer classes, and the manner in which Montana-Dakota proposed to design the final authorized rates established in this docket.

3. The pre-filed testimony of the MCC expert witnesses was filed in this docket on July 30, 2004. In that pre-filed testimony, the MCC contends that the Commission should decrease the annual revenues that Montana-Dakota is currently authorized to collect in Montana by $248,245. Additionally, the MCC has proposed an alternative allocation of the revenue deficiency between customer classes and alternative rate design to that proposed by Montana-Dakota in its Application in this docket.

4. The MCC developed revenue requirement in this case utilized a weighted cost of capital of 8.45%, including a cost of equity of 9.75%. Montana-Dakota contests the validity and the adequacy of the MCC developed cost of capital in this docket. In addition, the MCC has proposed other adjustments to the Montana-Dakota revenue requirement in this case.

5. A contested case hearing was held in this docket on November 17, 2004. However, a quorum of Commissioners was not available for the hearing, and it was heard by Commissioner Thomas Schneider, acting as hearing officer.

6. For settlement purposes, a fair and equitable resolution of the issues between Montana-Dakota and the MCC, one which would result in the establishment of just and reasonable rates, would be:

A. Montana-Dakota should be authorized to increase the Basic Service Charges contained in its Rates 60 and 70 as follows:

1. Rate 60, by 10 cents per month;
2. Rate 70, small meter, by 40 cents per month;
3. Rate 70, large meter, by 80 cents per month.

The above specified change in the Basic Service Charges is estimated to generate an additional $124,625 in annual revenue.

B. The agreed upon rate change should be implemented immediately, if possible for service rendered on and after February 1, 2005.

7. For Montana-Dakota, an essential component of this Stipulation is provision 6 B above, as no interim rate relief of any kind was authorized in this docket.

8. The Commission, after the completion of contested case proceedings in this docket, should be moved in its discretion to issue a final order approving, adopting, and

implementing the terms of this Stipulation.

9. The parties to this Stipulation present it to the Commission as a reasonable settlement of the issues raised in this docket. Neither party's position in this docket is accepted by the other party by virtue of their entry into this Stipulation, nor does it indicate their acceptance, agreement, or concession to any rate making principle, cost of service determination, or legal principle embodied, or arguably embodied, in this Stipulation.

10. The various provisions of this Stipulation are inseparable from the whole of the agreement between the parties to the Stipulation. The reasonableness of the proposed settlement set forth in this Stipulation is critically dependent upon its adoption, in its entirety, by the Commission. If the Commission decides not to adopt, in its entirety, the proposed settlement set forth in this Stipulation, then the entire Stipulation is null and void, no party to the Stipulation is bound by any provision of it, and it shall have no force or effect whatsoever.

Respectfully submitted January 14, 2005.

MONTANA CONSUMER COUNSEL

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Its Attorney
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ATTORNEYS FOR MONTANA DAKOTA

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-04-97

ORDER ADOPTING SETTLEMENT

September 22, 2004

Appearances

Commissioners: Anthony T. Clark, Susan E. Wefald, Kevin Cramer.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff.

Daniel S. Kuntz, Senior Attorney, MDU Resources Group, Inc., PO Box 5650, Bismarck, ND 58506-5650, appearing for Montana-Dakota Utilities Co.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, appearing as procedural Hearing Officer.

Preliminary Statement

On March 3, 2004, Montana-Dakota Utilities Co. a division of MDU Resources Group, Inc (MDU) filed an application with the North Dakota Public Service Commission to increase its natural gas rates by 2.8% annually. The requested increase in rates would generate additional revenues of $3,334,226 annually in North Dakota. MDU's application is based on a calendar 2005 projected test year. MDU also included a request for interim rate relief, based on a 2004 test year, to generate additional annual revenues of $1,869,539.

MDU proposed that all increases be flowed into the firm residential and commercial rate schedules, and that no change in rate levels be applied to the Air Force or small and large interruptible schedules. The proposed changes in rates by customer class are as follows: Residential, 3.5%, and Firm General Service, 2.3%. MDU estimates the proposed increase for a residential customer would average about $31.45 per year.

MDU stated that the primary reason for its application is increased operating expenses driven largely by increases in labor and benefit costs.

On March 31, 2004, the Commission suspended MDU's rates filed with its application and issued a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline. The technical hearing was scheduled for August 31, 2004, and Public Input Sessions via interactive video teleconference were scheduled for May 10, 2004, in Bismarck, Devils Lake, Dickinson, Jamestown, Minot and Williston.

The Notice of Hearing specified the following issues to be considered:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice of Intervention Deadline provided that any person wishing to intervene as a party in the proceeding must file a petition for intervention by May 24, 2004. No one petitioned to intervene as a party in the proceeding.

On April 15, 2004, Commission advisory staff filed a memo advising that MDU did not comply with the statute that authorizes interim rates because MDU did not properly adjust for inclusion of short-term debt in its capitalization structure, as was ordered by the Commission in MDU's most recent natural gas rate case, Case No. PU-399-02-183. Advisory staff further noted the law requires that any interim rate design may not change existing rate design and therefore advised that any interim rate increase must be applied equally to all customer classes, including the Air Force and interruptible customers.

On April 26, 2004, MDU submitted amended rate schedules for interim rate relief reflecting short-term debt in its capitalization structure resulting in a lower interim annual revenue requirement of $1,714,000 or 1.4293 percent spread equally to all customer classes.

On April 27, 2004, the Commission ordered the amended interim rates effective for service rendered on or after May 3, 2004.

Public Input Sessions were held via interactive video teleconference on May 10, 2004, in Bismarck, Devils Lake, Dickinson, Jamestown, Minot and Williston.

On July 15, 2004, the Commission advocacy staff (Staff) filed testimony recommending that MDU's revenue deficiency is $603,000 for the 2005 test year. Staff agreed with MDU's rate design to modestly increase the daily basic service charge, with the remainder to be recovered through the distribution delivery charge on a per dekatherm basis. Staff's agreement to MDU's rate design proposal was predicated on the Commission's acceptance of MDU's proposed weather normalization adjustment referred to as the Distribution Delivery Stabilization Mechanism (DDSM). However, Staff recommended changes to administer the DDSM in real time so as to recover additional revenue during winter months that are warmer than normal and less revenue when winter months are colder than normal.

On August 2, 2004, MDU filed rebuttal testimony disputing the revenue deficiency recommended by Staff. MDU agreed with Staff's real-time DDSM recommendation but proposed that it be calculated based on each individual customer's usage rather than customer class average deviations.

On August 24, 2004, MDU and Staff filed a Settlement Agreement. MDU and Staff agreed to:

1. A net increase in rates to yield increased annual revenues of $2,500,000 based on a return on rate base of 8.791 percent.
2. Basic service charge increases as proposed.
3. An increase to the residential customer class of approximately 2.5 percent and the general service class of approximately 1.9 percent with no increase to interruptible customers or to the Minot Air Force Base.
4. Establishment of the DDSM billing adjustment in form proposed by MDU in rebuttal testimony.

On August 31, 2004, a hearing was commenced as scheduled, but was immediately converted to an Informal Hearing to discuss the settlement agreement. At the Informal Hearing, MDU and staff discussed the settlement and summarized the basis for it. Generally, several issues originally disputed by staff were no longer disputed by staff after additional investigation and the filing of MDU rebuttal testimony. Consequently, the adjustments that these originally disputed items represented were no longer advocated by staff. In addition, at the Informal Hearing MDU addressed several questions and concerns raised by the Commission concerning language in the proposed DDSM tariff schedule. MDU agreed to revise the tariff language to address the Commission's concerns.

On September 8, 2004, the Commission issued a Notice of Rescheduled Hearing, rescheduling the hearing to September 20, 2004.

On September 10, 2004, MDU and Staff filed a Stipulation identifying issues no longer disputed and on which MDU and staff could agree in order to avoid holding a contested hearing on matters not in dispute. On September 20, 2004, a hearing was commenced as scheduled, but was immediately converted to a working session.

Having considered this matter, the Commission finds the Settlement Agreement filed August 24, 2004 is reasonable and should be approved. Therefore, the Commission issues the following:

Order

1. The Settlement Agreement filed August 24, 2004, a copy of which is attached to this Order and made a part of this Order, is APPROVED.

2. MDU's interim increase in annual revenues of approximately $1,714,000 will remain effective until the revised tariff sheets contemplated by this order take effect, at which time the interim rates will expire and be replaced by the rates reflected in the compliance tariffs. Since the final rates exceed the interim rates, no refunds will be due.

3. MDU shall file compliance tariffs to implement final rates, as agreed to in the Settlement Agreement and at the Informal Hearing, to yield a final annual revenue increase of not more than $2,500,000.

PUBLIC SERVICE COMMISSION

Susan E. Wefald **Commissioner**	**Tony Clark** **President**	**Kevin Cramer** **Commissioner**

RECEIVED
AUG 24 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.	)	**Case No. PU-04-97**
Natural Gas Rate Increase	)	
Application		

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into by and between Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company") and the Staff of the North Dakota Public Service Commission ("Staff"), (collectively the "Parties"). The Parties agree this Settlement Agreement resolves all outstanding issues in this case in a manner consistent with the public interest and will result in just and reasonable rates for the Company's retail natural gas operations in North Dakota.

PROCEDURAL HISTORY

1. On March 3, 2004, Montana-Dakota filed a notice of a proposed increase to its North Dakota retail natural gas rates to become effective April 2, 2004, based on a 2005 test year. The Notice proposed an increase in natural gas rates to provide additional annual revenue of $3,334,226, or 2.8 percent overall, over current rates. Montana-Dakota proposed to increase Distribution Delivery Charges for residential service customers by 5.5 percent and general service customers by 2.3 percent. The Company proposed no increase in rates for service to interruptible customers or to the Minot Air Force Base. Filed with the Notice were revised tariffs, direct testimony, exhibits and supporting statements.

2. Montana-Dakota concurrently submitted an Application and Notice for an

interim increase in natural gas rates in the annual amount of $1,871,000 to be effective 60 days from filing if the Commission suspended the proposed general rate increase. The Company subsequently revised its interim request to include short-term debt as part of the Company's cost of capital and to allocate the proposed interim rate increase equally to all customer classes with no change to existing rate design. The revised interim request sought an increase in annual revenue of $1,714,000. On April 27, 2004, the Commission issued an Order approving the revised interim rates to become effective May 3, 2004.

3. The North Dakota Public Service Commission ("Commission") suspended Montana-Dakota's general rate increase application and set the matter for investigation and hearing.

4. On March 31, 2004, the Commission issued a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline which set forth the following issues to be considered in this case:

> 1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?
>
> 2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
>
> 3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
>
> 4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
>
> 5. Are MDU's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

5. On May 10, 2004, the Commission conducted a Public Input Session via interactive video conference with hearing sites in Bismarck, Minot, Dickinson, Jamestown, Devils Lake and Williston.

6. No person has filed a petition to intervene in this proceeding.

7. Discovery requests were served on Montana-Dakota by the Staff and responded to by the Company.

8. On July 15, 2004, the Staff filed direct testimony of Charles W. King, President of the economic consulting firm of Snavely King Majoros O'Connor & Lee. In his direct testimony, Mr. King recommended various adjustments to the 2005 test year that, if adopted, would reduce the test year revenue requirement to $604,000. Mr. King further commented on Montana-Dakota's proposed rate design changes.

9. On August 2, 2004 and August 4, 2004, Montana-Dakota filed rebuttal testimony to the testimony of Mr. King. In its rebuttal testimony, Montana-Dakota responded to the adjustments recommended by Mr. King. The Company's rebuttal testimony included additional information and explanation on the test year items questioned by Mr. King.

10. Settlement discussions were held between the Parties on August 17, 2004 and August 20, 2004. As a result of those and subsequent discussions, the Parties reached this Settlement Agreement.

11. The Settlement Agreement is supported by the administrative record. Accordingly, the Parties jointly recommend the Commission issue an Order approving this Settlement Agreement in it's entirely, without conditions or modifications.

TERMS OF SETTLEMENT AGREEMENT

1. Revenue Increase. The Parties agree to, and recommend the Commission approve, a net increase in Montana-Dakota's natural gas rates for retail customers in North Dakota to yield an annual revenue increase of $2,500,000 effective October 3, 2004. This revenue increase is based upon a return on rate base of 8.791 percent.

2. Basic Service Charge. The Parties agree to, and recommend the Commission approve, that the changes in Montana-Dakota's retail rates to yield the revenue increase in paragraph 1 include an increase in Montana-Dakota's residential and general service Basic Service Charges as proposed by the Company.

3. Rate Design. The Parties agree to, and recommend the Commission approve, that the changes in Montana-Dakota's retail rates to yield the revenue increase in paragraph 1 include an increase in residential and general service retail Distribution Delivery Charges which, when combined with the revenue yielded from the Basic Service Charge changes in paragraph 2, result in an overall increase of total residential test year revenues of approximately 2.5 percent and general service revenues of approximately 1.9 percent. The Parties agree to, and recommend the Commission approve, no increase in the rates for service to interruptible customers or to the Minot Air Force Base.

4. The Parties agree to, and recommend the Commission approve, the Company's proposed Distribution Delivery Stabilization Mechanism Rate 87 as filed with the Rebuttal Testimony of Tamie A. Aberle.

OTHER TERMS AND CONDITIONS

1. Basis of Settlement.

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. The Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

2. Effect of the Settlement Negotiations.

It is understood and agreed that all offers of settlement and discussions related to this Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Public Service Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or otherwise.

3. Applicability and Scope.

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

4. Effective Date.

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The revised rates and tariff agreed to by

this Settlement Agreement shall be effective on the dates specified herein.

5. Modification.

If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if any party files a letter with the Commission within three (3) business days of notice of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

Dated this 24th day of August, 2004.

MONTANA-DAKOTA UTILITIES CO.

By: Donald R. Ball

Its: Assistant Vice President – Regulatory Affairs

Dated this 24th day of August, 2004.

NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF

By: [illegible]

Its: Chief Counsel

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
Natural Gas Rate Increase
Application

Case No. PU-04-97

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **23rd day of September day of September, 2004**, she deposited in the United States Mail, Bismarck, North Dakota, **two** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Order

The envelopes were addressed as follows:

Don Ball Montana-Dakota Utilities Co. 400 N 4th St Bismarck ND 58501	Dan Kuntz Montana-Dakota Utilities Co 400 N 4th St Bismarck ND 58501
Cert. No. 7001 2260 0001 3517 0807	**Cert. No. 7001 2260 0001 3517 0814**

Each addresses shown ares the respective addressee's last reasonably ascertainable post office address.

_____

Subscribed and sworn to before me
this **23rd day of September day of September, 2004**.

_____
Notary Public

SEAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	**ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION NG04-004**

On June 7, 2004, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its Black Hills service territory. The application seeks an increase in rates in the approximate amount of $1,281,417 or approximately 2.2%. On June 22, 2004, the Commission suspended the proposed schedule of rates for 90 days beyond June 7, 2004.

At its regularly scheduled meeting of June 22, 2004, the Commission found that pursuant to SDCL 49-1A-8, MDU shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 9, 2004. On July 15, 2004, Commission Staff advised the Commission that the suspension should have been for 90 days beyond July 7, 2004. On July 20, 2004, pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by MDU for 90 days beyond July 7, 2004.

The Commission set the matter for hearing for November 4 and 5, 2004, starting at 9:00 A.M., on November 4, 2004, in Room 412, State Capitol, 500 East Capitol, Pierre, South Dakota. On October 28, 2004, the Commission was informed that Commission Staff and MDU had reached a settlement agreement, so the hearing set for November 4 and 5, 2004, which was scheduled to hear the testimony of the parties was cancelled. On November 15, 2004, the Commission received a Joint Motion for Approval of Settlement Stipulation and Settlement Stipulation signed by all of the parties. On November 18, 2004, the Commission received Staff Memorandum Supporting Settlement Stipulation. Staff requested that the Commission consider the Settlement Agreement on November 30, 2004.

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.1, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, and 49-34A-23.

On November 30, 2004, the Commission heard from MDU and Commission Staff concerning the proposed Settlement Stipulation. After listening to the presentations, the Commission voted to grant the Joint Motion for Approval of Settlement Stipulation.

The tariff sheets approved by this order and effective for service rendered on and after December 1, 2004, are as follows:

Section No. 1
1st Revised Sheet No. 1, Canceling Original Sheet No. 1
1st Revised Sheet No. 1.1, Canceling Original Sheet No. 1.1

Section 3
9th Revised Sheet No. 1, Canceling 8th Revised Sheet No. 1
1st Revised Sheet No. 2, Canceling Original Sheet No. 2
1st Revised Sheet No. 11, Canceling Original Sheet No. 11
2nd Revised Sheet No. 13, Canceling 1st Revised Sheet No. 13
1st Revised Sheet No. 22.1, Canceling Original Sheet No. 22.1
1st Revised Sheet No. 26, Canceling Original Sheet No. 26

Section 5
1st Revised Sheet No. 1, Canceling Original Sheet No. 1
1st Revised Sheet No. 1.1, Canceling Original Sheet No. 1.1
1st Revised Sheet No. 1.2, Canceling Original Sheet No. 1.2
1st Revised Sheet No. 1.3, Canceling Original Sheet No. 1.3
1st Revised Sheet No. 1.4, Canceling Original Sheet No. 1.4
1st Revised Sheet No. 1.5, Canceling Original Sheet No. 1.5
1st Revised Sheet No. 1.6, Canceling Original Sheet No. 1.6
1st Revised Sheet No. 1.7, Canceling Original Sheet No. 1.7
1st Revised Sheet No. 1.8, Canceling Original Sheet No. 1.8
1st Revised Sheet No. 1.9, Canceling Original Sheet No. 1.9
1st Revised Sheet No. 1.10, Canceling Original Sheet No. 1.10
1st Revised Sheet No. 1.11, Canceling Original Sheet No. 1.11
1st Revised Sheet No. 1.12, Canceling Original Sheet No. 1.12
1st Revised Sheet No. 1.13, Canceling Original Sheet No. 1.13
1st Revised Sheet No. 1.14, Canceling Original Sheet No. 1.14
1st Revised Sheet No. 1.15, Canceling Original Sheet No. 1.15
1st Revised Sheet No. 1.16, Canceling Original Sheet No. 1.16
1st Revised Sheet No. 1.17, Canceling Original Sheet No. 1.17
1st Revised Sheet No. 1.18, Canceling Original Sheet No. 1.18
1st Revised Sheet No. 1.19, Canceling Original Sheet No. 1.19
1st Revised Sheet No. 24, Canceling Original Sheet No. 24

Section 6
1st Revised Sheet No. 5, Canceling Original Sheet No. 5
1st Revised Sheet No. 8, Canceling Original Sheet No. 8
Original Sheet No. 8.1
1st Revised Sheet No. 12, Canceling Original Sheet No. 12
1st Revised Sheet No. 13, Canceling Original Sheet No. 13
1st Revised Sheet No. 16, Canceling Original Sheet No. 16

It is therefore

ORDERED, that the Joint Motion for Approval of Settlement Stipulation is hereby granted. The Settlement Stipulation is incorporated by reference into this Decision and Order the same as if it had been set forth in its entirety herein.

Dated at Pierre, South Dakota, this 10th day of December, 2004.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 12/13/04

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

ROBERT K. SAHR, Chairman

GARY HANSON, Commissioner

JAMES A. BURG, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE NATURAL GAS RATES IN SOUTH DAKOTA.	))))	**JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION NG04-004**

Montana-Dakota Utilities Co. (Montana-Dakota) and the Staff of the South Dakota Public Utilities (Commission Staff), collectively referred to as Parties, hereby file the above-referenced Motion and Settlement Stipulation with the South Dakota Public Utilities Commission (Commission). The Parties propose that the Commission adopt the Settlement Stipulation as the settlement and resolution of all the issues in this proceeding. In support of this Mouton, the Parties submit as follows:

1. This Motion is made pursuant to ARSD 20:10:01:19.

2. The Settlement Stipulation resolves all of the issues in Docket No. NG04-004.

3. The Settlement Stipulation represents the conclusion of the undersigned parties that it is in the best interests of the Parties and the general public to reach a negotiated settlement of specific issues in this case and that the terms of the Settlement Stipulation agreed upon are just, fair, and reasonable, and consistent with South Dakota law.

For the foregoing reasons, the undersigned parties jointly request the Commission to adopt the attached Settlement Stipulation without modification for the purpose of resolving the specific issues for use in determining the revenue requirement of Montana-Dakota Utilities in Docket No. NG04-004.

Montana-Dakota Utilities Co.

BY: _____

Brett Koenecke
Attorney
May, Adam, Gerdes & Thompson, LLP
503 S. Pierre Street
PO Box 160
Pierre, SD 57501

DATED: 11/15/04

South Dakota Public Utilities Commission

BY: _____

Karen E. Cremer
Attorney
State Capital Building
500 E. Capitol
Pierre, SD 57501

DATED: _____

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE NATURAL GAS RATES IN SOUTH DAKOTA	)))))))	DOCKET NO. NG04-004

I. SETTLEMENT STIPULATION

On June 7, 2004, Montana-Dakota Utilities Co. ("Montana-Dakota") filed with the South Dakota Public Utilities Commission ("Commission") an application for approval to increase rates for natural gas service in the State of South Dakota for its Black Hills system. Montana-Dakota proposed an overall increase of $1,281,417. The Staff of the Commission ("Commission Staff") on October 19, 2004, filed its direct testimony supporting an overall increase for Montana-Dakota of $210,448.

The Commission Staff and Montana-Dakota (jointly the "Parties") held several negotiating sessions in an effort to arrive at a jointly acceptable resolution of this matter. As a result of the sessions, the Parties have been able to resolve all issues in this proceeding and have entered into this Settlement Stipulation ("Stipulation"), which, if accepted and ordered by the Commission, will determine rates to result from this proceeding.

II. PURPOSE

This Stipulation has been prepared and executed by the Parties for the sole purpose of resolving Docket No. NG04-004. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Settlement Agreement, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1. Upon execution of this Stipulation, the Parties shall immediately file this Stipulation with the Commission together with a joint motion requesting that the Commission issue an order approving this Stipulation in its entirety without condition or modification.

2. This Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any changes in or conditions to this Stipulation which are unacceptable to any party, this Stipulation shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3. This Stipulation shall become binding upon execution by the Parties, provided however, that if this Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void and privileged. This Stipulation is intended to relate only to the specific matters referred to herein; no party waives any claim or right which it may otherwise have with respect to any matter not

expressly provided for herein; no party shall be deemed to have approved, accepted, agreed or consented to any rate making principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Stipulation, or be prejudiced or bound thereby in any other current or future proceeding before the Commission. No party or representative thereof shall directly or indirectly refer to this Stipulation or that part of any order of the Commission referring to this Stipulation as precedent in any other current or future rate proceeding before the Commission.

4. The Parties to this proceeding stipulate that all prefiled testimony, exhibits, and workpapers be made a part of the record in this proceeding. The Parties understand that if this matter had not been settled, Montana-Dakota would have filed rebuttal testimony and the Commission Staff would have responded to certain of the positions contained in Montana-Dakota's rebuttal testimony.

5. It is understood that Commission Staff enters into this Stipulation for the benefit of Montana-Dakota's South Dakota customers affected by this docket.

III. ELEMENTS OF THE SETTLEMENT STIPULATION

1. Revenue Requirement

The Parties agree that Montana-Dakota's attached rate schedules are designed to produce annual increases in base rate levels (excluding purchased gas cost adjustment and sales taxes) of $669,549 annually for retail natural gas service in the Company's Black Hills service area in the State of South Dakota. The parties agree to an overall rate of return of 8.917%.

2. Tariffs

The increase will be allocated on an equal percentage basis to the Residential, Firm General Service and Large Interruptible rate classes resulting in an increase of 1.6% to each of the affected rate classes. The Tariffs reflect the following basic service charges with the remainder of the applicable revenue increase collected through the Distribution Delivery Charges:

Rate Class	Base Rate
Residential	$0.25 per day
Firm General	
Meters < 500 cubic ft./hour	$0.35 per day
Meters > 500 cubic ft./hour	$0.70 per day
Air Force	$95.00 per month
Small Interruptible Sales	$50.00 per month
Small Interruptible Transport	$125.00 per month
Large Interruptible Sales	$175.00 per month
Large Interruptible Transport	$225.00 per month

3. Implementation of Rates

The revised rate schedules shall be implemented with service rendered on and after December 1, 2004, with bills prorated so that usage prior to December 1, 2004 is billed at the previous rates and usage on and after December 1, 2004, is billed at the new rates.

4. Conclusion

This Stipulation is entered into this 15 day of November, 2004.

Montana-Dakota Utilities Co.

BY: _____

South Dakota Public Utilities Commission

BY: _____

Mr. Brett M. Koenecke
Attorney
May, Adam, Gerdes and Thompson
503 South Pierre Street
P.O. Box 160
Pierre, SD 57501

DATED: 11/15/04

Karen E. Cremer
Attorney
State Capitol Building
500 East Capitol Building
Pierre, SD 57501-5070

DATED:_____

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	**ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION NG05-002**

On March 24, 2005, Montana-Dakota Utilities Co. (MDU), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in its East River Natural Gas System service territory. The application seeks an increase in rates in the amount of $849,745 or approximately 12.8%.

At its regularly scheduled meeting of April 12, 2005, the Commission found that pursuant to SDCL 49-1A-8, MDU shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of April 29, 2005. On April 12, 2005, the Commission suspended the proposed schedule of rates for 90 days beyond April 23, 2005. On July 12, 2005, the Commission extended the suspension of proposed schedule of rates for 60 days beyond July 22, 2005.

On August 23, 2005, the Commission received a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation signed by all of the parties and Staff Memorandum Supporting Settlement Stipulation. Staff requested that the Commission consider the Settlement Stipulation on August 31, 2005.

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.1, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, and 49-34A-23.

On August 31, 2005, the Commission heard from MDU and Commission Staff concerning the proposed Settlement Stipulation. After listening to the presentations, the Commission voted to grant the Joint Motion for Approval of Settlement Stipulation.

The revised tariff sheets proposed by MDU, effective for service rendered on and after September 1, 2005, are as follows:

Section No. 1
2nd Revised Sheet No. 1, Canceling 1st Revised Sheet No. 1
2nd Revised Sheet No. 1.1, Canceling 1st Revised Sheet No. 1.1

Section No. 2
1st Revised Sheet No. 1, Canceling Original Sheet No. 1

Section 3
2nd Revised Sheet No. 2, Canceling 1st Revised Sheet No. 2
1st Revised Sheet No. 7, Canceling Original Sheet No. 7
Original Sheet No. 7.1
2nd Revised Sheet No. 11, Canceling 1st Revised Sheet No. 11
1st Revised Sheet No. 12, Canceling Original Sheet No. 12
3rd Revised Sheet No. 13, Canceling 2nd Revised Sheet No. 13

Original Sheet No. 17
Original Sheet No. 17.1
1st Revised Sheet No. 22, Canceling Original Sheet No. 22
2nd Revised Sheet No. 26, Canceling 1st Revised Sheet No. 26
2nd Revised Sheet No. 28, Canceling 1st Revised Sheet No. 28
1st Revised Sheet No. 28.1, Canceling Original Sheet No. 28.1
1st Revised Sheet No. 29, Canceling Original Sheet No. 29
1st Revised Sheet No. 29.2, Canceling Original Sheet No. 29.2
1st Revised Sheet No. 29.4, Canceling Original Sheet No. 29.4
1st Revised Sheet No. 30, Canceling Original Sheet No. 30
1st Revised Sheet No. 30.1, Canceling Original Sheet No. 30.1
1st Revised Sheet No. 30.2, Canceling Original Sheet No. 30.2
1st Revised Sheet No. 30.3, Canceling Original Sheet No. 30.3
1st Revised Sheet No. 30.4, Canceling Original Sheet No. 30.4
1st Revised Sheet No. 30.5, Canceling Original Sheet No. 30.5

Section 4
3rd Revised Sheet No. 1, Canceling 2nd Revised Sheet No. 1

Section 5
1st Revised Sheet No. 19, Canceling Original Sheet No. 19

It is therefore

ORDERED, that the Joint Motion for Approval of Settlement Stipulation is hereby granted. The Settlement Stipulation is incorporated by reference into this Decision and Order the same as if it had been set forth in its entirety herein; and it is further

ORDERED, that the aforementioned tariff sheets are approved for service rendered on and after September 1, 2005.

Dated at Pierre, South Dakota, this 7th day of September, 2005.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 9/8/05

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

Gary Hanson
GARY HANSON, Chairman

Robert K. Sahr
ROBERT K. SAHR, Commissioner

Dustin M. Johnson
DUSTIN M. JOHNSON, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	**JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION NG05-002**

Montana-Dakota Utilities Co. (Montana-Dakota) and the Staff of the South Dakota Public Utilities Commission (Commission Staff), collectively referred to as Parties, hereby file the above referenced Motion and Settlement Stipulation with the South Dakota Public Utilities Commission (Commission). The Parties propose that the Commission adopt the Settlement Stipulation as the settlement and resolution of all the issues in this proceeding. In support of this Motion, the Parties submit as follows:

1. This Motion is made pursuant to ARSD 20:10:01:19.

2. The Settlement Stipulation resolves all of the issues in Docket No. NG05-002.

3. The Settlement Stipulation represents the conclusion of the undersigned parties that it is in the best interests of the Parties and the general public to reach a negotiated settlement of specific issues in this case and that the terms of the Settlement Stipulation agreed upon are just, fair, and reasonable, and consistent with South Dakota law.

For the foregoing reasons, the undersigned parties jointly request the Commission to adopt the attached Settlement Stipulation without modification for the purpose of resolving the specific issues for use in determining the revenue requirement and appropriate rates of Montana-Dakota in Docket No. NG05-002

Montana-Dakota Utilities Co.

BY: _____

Brett Koenecke
Attorney
May, Adam, Gerdes & Thompson, LLP
503 S. Pierre Street
P.O. Box 160
Pierre, SD 57501-0160

DATED: August 22, 2005

SD Public Utilities Commission

BY: _____

Sara B. Greff
Staff Attorney
SD Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501

DATED: AUG. 22, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	**NG05-002**

I. SETTLEMENT STIPULATION

On March 24, 2005, Montana-Dakota Utilities Co. ("Montana-Dakota") filed with the South Dakota Public Utilities Commission ("Commission) an application for approval to increase rates for natural gas distribution service in the State of South Dakota for its East River Natural Gas System customers. Montana-Dakota stated they could justify a $1,786,862 overall increase but requested only an $849,745 overall increase. The Staff of the Commission ("Commission Staff") reviewed Montana-Dakota's case and determined that an increase in excess of Montana-Dakota's request was justified.

The Commission Staff and Montana-Dakota (jointly the "Parties") held several negotiating sessions in an effort to arrive at a jointly acceptable resolution of this matter. As a result of the sessions, the Parties have been able to resolve all issues in this proceeding and have entered into this Settlement Stipulation ("Stipulation"), which, if accepted and ordered by the Commission, will determine rates to result from this proceeding.

II. PURPOSE

This Stipulation has been prepared and executed by the Parties for the sole purpose of resolving Docket No. NG05-002. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue,

whether express or implied by the Settlement Agreement, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1. Upon execution of this Stipulation, the Parties shall immediately file this Stipulation with the Commission together with a joint motion requesting that the Commission issue an order approving this Stipulation in its entirety without condition or modification.

2. This Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any changes in or conditions to this Stipulation which are unacceptable to any party, this Stipulation shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3. This Stipulation shall become binding upon execution by the Parties, provided however, that if this Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void and privileged. This Stipulation is intended to relate only to the specific matters referred to herein; no party waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein; no party shall be deemed to have approved, accepted, agreed or consented to any rate making principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Stipulation, or be prejudiced or bound thereby in any other current or future proceeding before the Commission. No party or representative thereof shall directly or indirectly refer to this Stipulation or that part of any

order of the Commission referring to this Stipulation as precedent in any other current or future rate proceeding before the Commission.

4. The Parties to this proceeding stipulate that all pre-filed testimony, exhibits, and work papers be made a part of the record in this proceeding. The Parties understand that if this matter had not been settled, Staff would have filed pre-filed testimony and Montana-Dakota would have filed rebuttal testimony and the Commission Staff would have responded to certain of the positions contained in Montana-Dakota's rebuttal testimony.

5. It is understood that Commission Staff enters into this Stipulation for the benefit of Montana-Dakota's South Dakota customers affected by this docket.

III. ELEMENTS OF THE SETTLEMENT STIPULATION

1. Revenue Requirement

The Parties agree that Montana-Dakota's attached rate schedules are designed to produce annual increases in base rate levels (excluding purchased gas cost adjustment and sales taxes and rounded as close as possible to Montana-Dakota's request) of $850,156 annually for retail natural gas service in Montana-Dakota's East River Natural Gas service area in the State of South Dakota. The parties agree to an overall rate of return of 8.9% for the purposes of Purchased Gas Adjustment and other similar carrying charge calculations.

2. Tariffs

The Tariffs reflect the following basic service charges with the remainder of the applicable revenue increase collected through the Distribution Delivery Charges:

Rate Class	Base Service Charge

Residential	15 cents/day
Firm General	
Meters < 500 cubic ft./hour	25 cents/day
Meters > 500 cubic ft./hour	50 cents/day

3. Implementation of Rates

The revised rate schedules, attached hereto, shall be implemented with service rendered on and after September 1, 2005, with bills prorated so that usage prior to September 1, 2005, is billed at the previous rates and usage on and after September 1, 2005, is billed at the new rates.

4. Conclusion

This Stipulation is entered into this 22nd day of August, 2005.

Montana-Dakota Utilities Co.

BY: _____

Brett Koenecke
Attorney
May, Adam, Gerdes & Thompson, LLP
503 S. Pierre Street
P.O. Box 160
Pierre, SD 57501-0160

DATED: August 22 2005

SD Public Utilities Commission

BY: _____

Sara B. Greff
Staff Attorney
SD Public Utilities Commission
500 E. Capitol Avenue
Pierre, SD 57501

DATED: AUG. 22, 2005

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO., FOR AUTHORITY TO INCREASE RATES FOR WYOMING GAS UTILITY SERVICE BY $662,152 PER ANNUM OR 5.6%, INCLUDING RESIDENTIAL, 5.7% AND FIRM GENERAL SERVICE, 5.5%	)	**DOCKET NO. 30013-GR-02-127 (RECORD NO. 7524)**

APPEARANCES

BRUCE S. ASAY of Associated Legal Group, LLC
Cheyenne, Wyoming
for the Applicant Montana-Dakota Utilities Co.

ANTHONY M. REYES, Cheyenne, Wyoming,
for Intervenor Consumer Advocate Staff of the
Wyoming Public Service Commission

HEARD BEFORE

CHAIRMAN STEVE ELLENBECKER
DEPUTY CHAIRMAN STEVE FURTNEY

Chairman Ellenbecker, presiding

ORDER CONFIRMING BENCH DECISION APPROVING STIPULATION OF PARTIES
(Issued February 6, 2003)

This matter is before the Wyoming Public Service Commission, hereinafter referred to as the Commission, upon the application of Montana-Dakota Utilities, Co., hereinafter referred to as MDU or the Company, for authority to increase rates for Wyoming gas utility service by $662,152 per annum or 5.6%, including residential, 5.7% and firm general service, 5.5%.

The Commission considered the evidence of record in this case, its files concerning the application and the Stipulation and Agreement, hereinafter referred to as the Stipulation, submitted to the Commission at the public hearing. The Stipulation was entered into between MDU and Intervenor Consumer Advocate Staff of the Wyoming Public Service Commission, hereinafter referred to as the CAS, collectively referred to as the Parties. The Commission having furthered reviewed applicable Wyoming utility law and being otherwise fully advised in the premises, FINDS and CONCLUDES:

FINDINGS ON PARTIES AND PROCEDURE

1. On June 11, 2002, MDU filed an application requesting authority to increase rates for Wyoming gas utility service by $662,152 per annum or 5.6%, including residential, 5.7% and firm general service, 5.5%. MDU's application provides that the proposed increase for a residential customer will average about $2.60 per month or approximately $31.00 per year.

2. The Commission issued its Suspension Order on May 17, 2002, suspending the proposed rate increase, pending further investigation in the public interest, pursuant to W.S. § 37-3-106.

3. MDU, a Division of MDU Resources Group, Inc., a Delaware corporation, is authorized to do business in Wyoming. It is a public utility as defined by W.S. § 37-1-101(a)(vi) and, as such, is subject to the Commission's jurisdiction pursuant to the provisions off W.S. § 37-2-112, 117, 119, 120, 121 and 122.

4. The Consumer Advocate Staff (CAS) consists of employees of the Public Service Commission of Wyoming who have been authorized by the Commission to act as a party to these proceedings. The CAS, in fulfilling its statutory mandate to promote the best interests of the citizens of the state, or a broad class of citizens, appears in a capacity distinct, separate and apart from the Commission.

5. As part of its application, MDU submitted prefiled testimony and exhibits of C. Wayne Fox, J. Stephen Gaske, Craig A. Keller, Rita A. Mulkern, Richard A. Espeland, Russell A. Feingold, and Tamie A. Aberle.

6. The application stated that MDU's Wyoming natural gas distribution system serves approximately 14,900 customers in eight communities. The customer mix is approximately 87% residential, 13% firm commercial, with small interruptible and large interruptible customers making up less than 1% of the customer base. The total annual gas used by Wyoming firm service customers is approximately 2.2 million dk as projected for 2003 in the rate proceeding.

7. In addition to its revenue request, Applicant proposed as a change in policy that it own all service lines on a prospective basis. Although customers presently own service lines in Montana-Dakota's service territory, Applicant proposed that it own, and pay for, all new and replacement service lines in the future.

8. Applicant also proposed a change in rate structure that would allow an additional measure of protection from the financial effect of temperature changes in the weather.

9. After its intervention, CAS reviewed the application to determine the need for relief by the Company. The investigation included an examination of a detailed cost-of-service analysis provided by Applicant. In addition, CAS prepared and received responses to numerous information requests, which were exchanged during the course of the proceeding. Applicant and CAS debated all aspects of the filing, possible adjustments to the filing and implementation of any changes in rates. The analysis by CAS indicated that

a general increase in MDU's Wyoming revenue requirement is just and reasonable and consistent with the pubic interest. The rate design proposed by Montana-Dakota is also appropriate and designed to recover the rates in a manner that is just and reasonable.

10. A Notice Of Application was issued July 18, 2002 establishing a deadline of August 19, 2002 for anyone desiring to intervene, file a statement, representation, protest, complaint or request for hearing regarding the application. The Notice was published and a public service announcement concerning the application was broadcast on public radio. The Consumer Advocate Staff petitioned, and was granted intervention status. Other statements and representations received by the Commission were made a part of the record and considered in the decision of the Commission. No other person requested to be an intervenor in this proceeding.

11. Pursuant to the Commission's Order, and in accordance with the Wyoming Administrative Procedure Act and the Commission's Procedural Rules and Regulations, the Commission held the public hearing regarding this matter on December 9, 2002. All the parties appeared and had a full opportunity to present evidence, to cross-examine witnesses and otherwise participate in the proceedings. MDU and the CAS offered into evidence a Stipulation and Agreement, hereinafter referred to as the Stipulation, which was entered into on December 6, 2002, and submitted to the Commission at the public hearing on December 9, 2002. The Stipulation addressed and resolved issues existing as between the parties.

12. At the conclusion of the December 9, 2002, public hearing, the Commission deliberated this matter and issued a bench decision whereby the Commission adopted the Stipulation and approved the terms and conditions as supported in the Stipulation.

13. On December 19, 2002, the Commission, in regular open meeting, reconfirmed the bench decision of December 9, 2002, adopting the Stipulation and approving the terms and conditions supported therein, as well as approving Tariff No. 6, with the exception of the summary sheet, for an effective date of January 1, 2003. The Stipulation and Agreement is incorporated herein, as a part of this Order.

FINDINGS OF FACT

Summary of the Stipulation and Agreement's Terms and Conditions:

14. The terms and conditions contained in the Stipulation and Agreement, generally reflect the following:

A. The existing annual additional revenue requirement for Montana-Dakota's Wyoming operations is stipulated to be $465,855 which is an overall revenue increase of 3.95%; this amount is just and reasonable. This overall determination results from a comprehensive consideration by the Parties of many factors, including those described herein.

B. Applicant utilizes a jurisdictional accounting system that directly assigns and/or allocates revenue, expense and rate base to the appropriate jurisdictions as part of a regular accounting process. The allocation methods and procedures are the same as

have previously been adopted by the Commission based on principles of cost causation assignability.

C. The parties agree and stipulate to the use of a projected average 2003 test year, with test year net earnings of $152,391, to determine the Company's revenue requirement. The rate base utilized by the Company, and agreed to by the CAS, in determining its revenue requirement is $5,079,977.

D. No return on common equity was agreed to by the parties in this Stipulation and Agreement. However, the parties agree and stipulate that an overall just and reasonable authorized rate of return on Montana-Dakota's Wyoming rate base should be established at 8.94%. The parties further agree and stipulate that the rate of return for calculating the Applicant's Purchased Gas Cost adjustments will be 9.00%. Stipulation Exhibit No. 1 presents the rate base, authorized return on rate base, test year net earnings and revenue requirement stipulated and agreed to by the parties in this proceeding.

E. The rate design proposed by Montana-Dakota is stipulated to be appropriate and designed to recover the rates in a manner that is just and reasonable. Stipulation Exhibit No. 2, page 1, shows the increase in revenues by core service rate class. Stipulation Exhibit No. 2, page 2, indicates the rates for the Basic Service Charge and Delivery Distribution Charge based on the stipulated additional annual revenue requirement of $465,855. Stipulation Exhibit No. 3, pages 1-4, illustrate the bill comparison details for the core service rate classes based on this Stipulation and Agreement.

COMMISSION CONCLUSIONS OF LAW

1. MDU is a public utility company as defined by W.S. § 37-15-103(a)(xi) and as such, is subject to the jurisdiction of this Commission pursuant to the provisions of W.S. § 37-15-401.

2. Proper notice of the application and public hearing in this matter was given in full compliance with the requirements of the Wyoming Administrative Procedure Act, and the relevant provisions of the Commission's Procedural Rules and Special Regulations. All proceedings in this matter have in all respects been conducted in compliance with the requirements of the Wyoming Administrative Procedure Act and the Commission's Rules.

3. The intervention of the CAS was properly granted and this entity became a party to this proceeding as defined in the Wyoming Administrative Procedure Act.

4. Public deliberations were held, with regard to this matter, pursuant to the provisions of W.S. § 16-4-403.

5. The Commission may approve a stipulation or agreed upon settlement as a means of disposing of any matter coming before it at hearing, pursuant to Commission Rule Section 119.

6. The Commission concludes that the Stipulation, entered into between the Parties, represents a just, equitable and reasonable resolution of the issues in this service quality requirement proceeding. The Commission further concludes that approval of the

Stipulation helps move MDU closer to compliance with the Commission's rules, and therefore, approval of the Stipulation is in the public interest.

IT IS THEREFORE ORDERED THAT:

1. Pursuant to the bench decision rendered by the Commission at the conclusion of the public hearing held in this matter on December 9, 2002, the application of Montana-Dakota Utilities, Co. for authority to increase rates for Wyoming gas utility service as modified by the Stipulation and Agreement entered into by the parties, for an additional revenue requirement of $465,855 or 3.95%, is hereby, approved effective January 1, 2003.

2. This Order is effective immediately.

MADE AND ENTERED at Cheyenne, Wyoming, February 6, 2003.

PUBLIC SERVICE COMMISSION OF WYOMING

STEVE ELLENBECKER, Chairman

STEVE FURTNEY, Deputy Chairman

KRISTIN H. LEE, Commissioner

PUBLIC SERVICE COMMISSION OFFICIAL SEAL OF WYOMING

(SEAL)

ATTEST:

DOUGLAS J. MOENCH, Assistant Secretary

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO., FOR AUTHORITY TO INCREASE RATES FOR WYOMING GAS UTILITY SERVICE BY $662,152 PER ANNUM OR 5.6%, INCLUDING RESIDENTIAL, 5.7% AND FIRM GENERAL SERVICE, 5.5%	)	DOCKET NO. 30013-GR-02-127

STIPULATION AND AGREEMENT

This Stipulation and Agreement ("Stipulation") is agreed to and entered into between the Consumer Advocate Staff of the Public Service Commission of Wyoming ("CAS"), and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., ("Applicant" or "Montana-Dakota" or "Company"). The Applicant and CAS shall be referred to hereinafter, collectively, as the "Parties".

PROCEDURAL BACKGROUND

1. On June 10, 2002, Montana-Dakota filed with the Wyoming Public Service Commission ("Commission"), an application for authority to increase rates for Wyoming gas utility service by $662,152 per annum or 5.6%, including residential, 5.7% and firm general service, 5.5%. Testimony and exhibits in support of the application were filed with the application of Montana-Dakota.

2. The Commission issued its Suspension Order on June 19, 2002, suspending the proposed rate increase, pending further investigation, pursuant to W.S. § 37-3-106.

3. On July 18, 2002, the Commission issued its Notice of Application which provided for an August 19, 2002, deadline in which interested parties could intervene, file a statement, representation, protest, complaint or request for hearing with regard to this matter.

4. On July 30, 2002, the Consumer Advocate Staff of the Wyoming Public Service Commission filed a Motion to Intervene. This motion was approved on August 13, 2002.

5. After having received the intervention of the CAS, as well as several complaint letters from Montana-Dakota customers, the Commission determined that a hearing was necessary to further review the merits of the application. Accordingly, the Commission issued a Notice of Hearing on October 5, 2002, in which it notified the public of a hearing to be held on Monday, December 9, 2002, in the 2nd Floor Meeting Room of the new addition to the Sheridan Courthouse, 224 S. Main Street, Sheridan, Wyoming.

6. The Commission directed, as part of its Notice, that any person who wished to appear at the public hearing to protest or comment on this application might do so either by notifying the Commission in advance, or by appearing and requesting to speak at the public hearing.

DESCRIPTION OF THE PARTIES AND APPLICATION

7. Montana-Dakota, a Division of MDU Resources Group, Inc., a Delaware corporation, is authorized to do business in Wyoming. It is a public utility as defined by W.S. § 37-1-101(a)(vi) and, as such, is subject to the Commission's jurisdiction pursuant to the provisions off W.S. § 37-2-112, 117, 119, 120, 121 and 122.

8. The CAS consists of employees of the Public Service Commission of Wyoming who have been authorized by the Commission to act as a party to these proceedings. The CAS, in fulfilling its statutory mandate to promote the best interests of the citizens of the state, or a broad class of citizens, appears in a capacity distinct, separate and apart from the Commission.

9. Although appropriate notice was provided to the public, no other person requested to be an intervenor in this proceeding.

10. Montana-Dakota seeks authority to increase rates for Wyoming gas utility service by $662,152 per annum or 5.6%, including residential, 5.7% and firm general service, 5.5%. On June 10, 2002, Montana-Dakota filed an application requesting such authority and provided supporting documentation. Montana-Dakota's application provides that the proposed increase for a residential customer will average about $2.60 per month or approximately $31.00 per year.

11. As part of its application, Montana-Dakota submitted prefiled testimony and exhibits of C. Wayne Fox, J. Stephen Gaske, Craig A. Keller, Rita A. Mulkern, Richard A. Espeland, Russell A. Feingold, and Tamie A. Aberle.

12. The application stated that Montana-Dakota's Wyoming natural gas distribution system serves approximately 14,900 customers in eight communities. The customer mix is approximately 87% residential, 13% firm commercial, with small interruptible and large interruptible customers making up less than 1% of the customer share. The total annual gas used by Wyoming firm service customers is approximately 2.2 million dk as projected for 2003 in the rate proceeding.

13. In addition to its revenue request, Applicant proposed as a change in policy that it own all service lines on a prospective basis. Although customers presently own service lines in Montana-Dakota's service territory, Applicant proposed that it own, and pay for, all new and replacement service lines in the future.

14. Applicant also proposed a change in rate structure that would allow an additional measure of protection from the financial effect of temperature changes in the weather.

15. After its intervention, CAS reviewed the application to determine the need for

relief by the company. The investigation included an examination of a detailed cost-of-service analysis provided by Applicant. In addition, CAS prepared and received responses to numerous information requests, which were exchanged during the course of the proceeding. Applicant and CAS debated all aspects of the filing, possible adjustments to the filing and implementation of any changes in rates. The analysis by CAS indicated that a general increase in Montana-Dakota's Wyoming revenue requirement is just and reasonable and consistent with the pubic interest. The rate design proposed by Montana-Dakota is also appropriate and designed to recover the rates in a manner that is just and reasonable.

AGREEMENT

GENERAL PROVISIONS

16. In an effort to avoid a protracted and fully contested general rate proceeding, the Parties hereby stipulate and agree, subject to Commission approval, as follows:

17. The Parties agree that this Stipulation and Agreement represents a compromise in the positions of the Parties.

18. The Parties agree that the terms and conditions of this Stipulation and Agreement shall not become effective until the date of a final decision by the Commission approving this Stipulation and Agreement without modification of any material term, which is unacceptable to any Party.

19. In the event that the Commission modifies any material term of this Stipulation and Agreement, which modification is unacceptable to any party hereto, that party shall so notify the other party within ten (10) days after the decision becomes effective. In that event, this Stipulation and Agreement shall be considered null and void and of no force and effect in this or any other proceeding. In that event this Stipulation and Agreement, its terms and conditions, and

the negotiations or discussions undertaken in conjunction with this Stipulation and Agreement shall not be admissible in evidence in this or any other proceeding.

20. The Parties agree that this Stipulation and Agreement represents a just, equitable and reasonable resolution of all issues, which were or could have been contested by the Parties in this docket.

21. The existing annual additional revenue requirement for Montana-Dakota's Wyoming operations is stipulated to be $465,855 which is an overall revenue increase of 3.95%; this amount is just and reasonable. This overall determination results from a comprehensive consideration by the Parties of many factors, including those described herein.

22. Applicant utilizes a jurisdictional accounting system that directly assigns and/or allocates revenue, expense and rate base to the appropriate jurisdictions as part of a regular accounting process. The allocation methods and procedures are the same as have previously been adopted by the Commission based on principles of cost causation assignability.

23. The parties agree and stipulate to the use of a projected average 2003 test year, with test year net earnings of $152,391, to determine the Company's revenue requirement. The rate base utilized by the Company, and agreed to by the CAS, in determining its revenue requirement is $5,079,977.

24. No return on common equity was agreed to by the parties in this Stipulation and Agreement. However, the parties agree and stipulate that an overall just and reasonable authorized rate of return on Montana-Dakota's Wyoming rate base should be established at 8.94%. The parties further agree and stipulate that the rate of return for calculating the Applicant's Purchased Gas Cost adjustments will be 9.00%. Stipulation Exhibit No. 1 presents

the rate base, authorized return on rate base, test year net earnings and revenue requirement stipulated and agreed to by the parties in this proceeding.

25. The rate design proposed by Montana-Dakota is stipulated to be appropriate and designed to recover the rates in a manner that is just and reasonable. Stipulation Exhibit No. 2, page 1, shows the increase in revenues by core service rate class. Stipulation Exhibit No. 2, page 2, indicates the rates for the Basic Service Charge and Delivery Distribution Charge based on the stipulated additional annual revenue requirement of $465,855. Stipulation Exhibit No. 3, pages 1-4, illustrate the bill comparison details for the core service rate classes based on this Stipulation and Agreement.

26. This Stipulation and Agreement is a unitary whole document; any party may withdraw from it if this Stipulation and Agreement is not approved in its entirety by the Commission. In the event that any part or all of the Stipulation and Agreement is not approved by the Commission, or is otherwise disapproved by any court of competent jurisdiction, then neither the Commission nor any party to the Stipulation and Agreement shall be prejudiced by the terms of this pleading and each party shall be entitled to file testimony and to cross-examine witnesses, and in general, to proceed and prosecute its entire case with its full claims and rights preserved.

27. All negotiations related to this Stipulation and Agreement are privileged and confidential and no party shall be bound by any position asserted in the negotiations. Execution of this Stipulation and Agreement shall not be deemed to constitute an acknowledgement by any party of the validity of any theory, principal or practice of rate making, nor shall it be construed to constitute the basis of an estoppel or waiver by any party.

28. The Parties believe settlement of this proceeding through this Stipulation and

Agreement is in the public interest and that the rates resulting from the Agreement are just and reasonable.

29. This Stipulation and Agreement will be presented to the Commission for approval; the Parties request in submitting this Stipulation and Agreement that the Commission approve the same and that the rates be allowed to go into effect on a service rendered basis on and after January 1, 2003.

30. In presenting the Stipulation and Agreement to the Commission for approval, it is the intent of the Parties, Montana-Dakota and CAS, that as deemed appropriate by the Commission, they will each present the testimony of a witness to explain the Stipulation and Agreement as well as their support for the Agreement.

31. No party shall hereafter be deemed to be bound by any position asserted by any party and no finding of fact or conclusion of law, other than those incorporated herein, shall be deemed to be intended by this Stipulation and Agreement.

32. The entry by the Commission of an order approving this Stipulation and Agreement shall not be deemed to effect any estoppel upon the Commission, or otherwise establish or create any limitation or precedent for the Commission.

33. This Stipulation and Agreement shall not become effective until approved by this Commission.

34. This Stipulation and Agreement may be executed in one or more identical counterparts and upon execution by the Parties, each executed counterpart shall have the same force and effect as the original instrument and as if all the parties had signed the same instrument. Any signature page of the Stipulation and Agreement may be detached from any counterpart of this Stipulation and Agreement without impairing the legal effect of any

signatures thereon, and may be attached to another counterpart of this Stipulation and Agreement identical in form hereto, but having attached to it one or more signature pages.

IN WITNESS WHEREOF, the Parties hereto have executed this Stipulation and Agreement this 6th day of December, 2002.

CONSUMER ADVOCATE STAFF OF THE
PUBLIC SERVICE COMMISSION OF WYOMING

By: _____ 12/6/02
Date

MONTANA-DAKOTA UTILITIES CO.

By: _____ Dec. 6, 2002
Date

Asst. Secretary

Stipulation Exhibit No. 1

Montana-Dakota Utilities
Docket 30013-GR-02-127
Stipulated Rate Base,
Authorized Return on Rate Base,
Test Year Net Earnings
and Revenue Requirement

Rate Base	$5,079,977
Return on Rate Base	8.94%
Earnings Requirement	$454,150
Test Year Net Earnings	$152,391
Earnings Deficiency	$301,759
Revenue Multiplier	1.5438
Revenue Requirement	$465,855

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - WYOMING
ANNUAL REVENUES UNDER CURRENT AND PROPOSED RATES
DOCKET NO. 30013-GR-02-127

CORE SERVICE	Bills	Dk	ADJUSTED TEST YEAR RESULTS Distribution Revenues	Gas Costs	Total Revenues	MDU Increase in Revenue	Percent Increase
Residential - Rate 60	157,308	1,323,807	2,454,865	5,033,115	7,487,980	424,928	5.67%
Firm General Service - Rate 70 & 72	22,620	849,568	1,072,746	3,230,057	4,302,803	237,341	5.52%
Total Wyoming	179,928	2,173,375	3,527,611	8,263,172	11,790,783	662,269	5.62%

CORE SERVICE	Bills	Dk	ADJUSTED TEST YEAR RESULTS Distribution Revenues	Gas Costs	Total Revenues	STIPULATED Increase in Revenue	Percent Increase
Residential - Rate 60	157,308	1,323,807	2,454,865	5,033,115	7,487,980	**295,970**	**3.95%**
Firm General Service - Rate 70 & 72	22,620	849,568	1,072,746	3,230,057	4,302,803	**169,808**	**3.95%**
Total Wyoming	179,928	2,173,375	3,527,611	8,263,172	11,790,783	**465,778**	**3.95%**

PROPOSED RATES BY CLASS OF SERVICE FROM STIPULATION		
Tariff	Basic Service Charge	Dist. Delivery Charge ($/Dk)
CORE SALES		
Residential	$0.40/day	$0.633
Firm General Service:		
Meters < 500 Cubic/ft	$0.90/day	$0.583
Meters > 500 Cubic/ft	$1.80/day	$0.583
Optional Seasonal Gas		
Meters < 500 Cubic/ft	$0.90/day	$0.583
Meters > 500 Cubic/ft	$1.80/day	$0.583
NON-CORE SALES		
Small Interruptible Sales	$95.00/month	Per Contract
Small Interruptible Trans.	$145.00/month	
Maximum		$0.471
Minimum		$0.100
Large Interruptible Trans.	$250.00/month	
Maximum		$0.161
Minimum		$0.020
Large Interruptible Sales	$200.00/month	Per Contract

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - WYOMING
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE (SMALL METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	19	$83.90	$83.45	($0.45)	-0.54%
February	15	68.13	68.44	0.31	0.46%
March	13	60.25	60.94	0.69	1.14%
April	9	44.48	45.93	1.45	3.26%
May	7	36.59	38.42	1.83	5.01%
June	3	20.33	23.42	3.09	15.18%
July	2	16.13	19.66	3.53	21.91%
August	2	16.13	19.66	3.53	21.91%
September	2	16.13	19.66	3.53	21.91%
October	5	28.71	30.92	2.21	7.70%
November	10	48.42	49.68	1.26	2.60%
December	15	68.13	68.44	0.31	0.46%
Total	102	$507.33	$528.62	$21.29	4.20%

PRESENT RATE 60: 1/	
Base Rate	$7.75
1st 5 dk	$4.192
Over 5 dk	$3.942
PROPOSED RATE 60: 2/	
Basic Delivery Charge	$12.16
Disbribution Delivery	$0.633
Cost of Gas	$3.119

1/ Rate Effective June 1, 2002
2/ Includes June 2002 Cost of Gas based on .68% loss factor plus surcharge, incentive adjustment and non-core credit.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - WYOMING
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE (LARGE METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	67	$278.11	$263.54	($14.57)	-5.24%
February	46	195.33	184.75	(10.58)	-5.42%
March	47	199.27	188.50	(10.77)	-5.40%
April	33	144.09	135.98	(8.11)	-5.63%
May	20	92.84	87.20	(5.64)	-6.07%
June	10	53.42	49.68	(3.74)	-7.00%
July	6	37.65	34.67	(2.98)	-7.91%
August	6	37.65	34.67	(2.98)	-7.91%
September	7	41.59	38.42	(3.17)	-7.61%
October	18	84.96	79.70	(5.26)	-6.20%
November	30	132.26	124.72	(7.54)	-5.70%
December	41	175.62	165.99	(9.63)	-5.48%
Total	331	$1,472.79	$1,387.83	-$84.96	-5.77%

PRESENT RATE 60: 1/	
Base Rate	$12.75
1st 5 dk	$4.192
Over 5 dk	$3.942
PROPOSED RATE 60: 2/	
Basic Delivery Charge	$12.16
Disbribution Delivery	$0.633
Cost of Gas	$3.119

1/ Rate Effective June 1, 2002
2/ Includes June 2002 Cost of Gas based on .68% loss factor plus surcharge, incentive adjustment and non-core credit.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - WYOMING
RATE 60 BILL COMPARISON
FIRM GENERAL SERVICE (SMALL METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	38	$166.42	$168.04	$1.62	0.97%
February	30	135.07	$138.42	3.35	2.48%
March	25	115.48	$119.91	4.43	3.84%
April	17	84.12	$90.29	6.17	7.34%
May	11	60.61	$68.08	7.47	12.33%
June	5	35.85	$45.87	10.02	27.95%
July	4	31.68	$42.17	10.49	33.11%
August	4	31.68	$42.17	10.49	33.11%
September	4	31.67	$42.17	10.50	33.15%
October	7	44.18	$53.27	9.09	20.58%
November	17	84.12	$90.29	6.17	7.34%
December	28	127.23	$131.02	3.79	2.98%
Total	190	$948.11	$1,031.70	$83.59	8.82%

PRESENT RATE 70: 1/	
Base Rate	$15.00
1st 10 dk	$4.169
Over 10 dk	$3.919
PROPOSED RATE 70: 2/	
Basic Delivery Charge	$27.36
Disbribution Delivery	$0.583
Cost of Gas	$3.119

1/ Rate Effective June 1, 2002
2/ Includes June 2002 Cost of Gas based on .68% loss factor plus surcharge, incentive adjustment and non-core credit.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - WYOMING
RATE 60 BILL COMPARISON
FIRM GENERAL SERVICE (LARGE METERS)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	254	$1,017.93	$995.03	($22.90)	-2.25%
February	203	818.06	$806.23	(11.83)	-1.45%
March	173	700.49	$695.17	(5.32)	-0.76%
April	127	520.21	$524.87	4.66	0.90%
May	99	410.48	$421.22	10.74	2.62%
June	61	261.56	$280.54	18.98	7.26%
July	35	159.67	$184.29	24.62	15.42%
August	35	159.67	$184.29	24.62	15.42%
September	37	167.50	$191.69	24.19	14.44%
October	74	312.51	$328.67	16.16	5.17%
November	136	555.48	$558.19	2.71	0.49%
December	195	786.71	$776.61	(10.10)	-1.28%
Total	1,429	$5,870.27	$5,946.80	$76.53	1.30%

PRESENT RATE 70: 1/	
Base Rate	$20.00
1st 10 dk	$4.169
Over 10 dk	$3.919
PROPOSED RATE 70: 2/	
Basic Delivery Charge	$54.72
Disbribution Delivery	$0.583
Cost of Gas	$3.119

1/ Rate Effective June 1, 2002
2/ Includes June 2002 Cost of Gas based on .68% loss factor plus surcharge, incentive adjustment and non-core credit.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-051 RE: Form 2
Witness - Goodin

Provide a copy of the 2010 and 2011 Form 2.

Response:

Montana-Dakota does not file a FERC Form 2.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-052 RE: Reports to Stockholders
Witness - Goodin

Provide a copy of the Annual Report to Stockholders for each year from 2006 through 2011.

Response:

Please see Attachment A on the enclosed CD. The Annual Report to Stockholders is also available on the Company's website at www.mdu.com.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-053 Reports to Stockholders
Witness - Goodin

Provide a copy of each Quarterly Report to Stockholders for each quarter of 2010, 2011 and 2012 as available.

Response:

MDU Resources did not publish a Quarterly Report to Stockholder for the requested time period.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-061 RE: Statement E, Adjustment D - Gas in underground storage
Witness - Mulkern

Assuming the volumes and prices requested in MCC-059 and MCC-060 are provided on a total Company basis, provide a detailed explanation and all documentation that support the allocation/assignment of gas stored underground to Montana.

Response:

Gas stored underground is allocated to Montana based on the ratio of the contracted capacity (MDDQ) for Montana to the total contracted capacity. Please see the Statement Workpapers, page E-1 for the factor used to allocate gas in underground storage.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-063 **RE: Statement E, Adjustment F - Prepaid Demand and Commodity Charges**
Witness - Mulkern

a. Provide a schedule that shows actual prepaid demand and commodity charges for each month from July 2012 through the most recent month available.

b. Assuming these payments are on a total gas utility basis, provide a detailed explanation and all documentation that support the allocation/assignment to Montana.

Response:

a. The Prepaid Demand and Commodity charges for July 2012 to October 2012 were:

	Prepaid Demand	Prepaid Commodity	Total
July	$616,778	$68,693	$685,471
August	1,268,285	107,632	1,375,916
September	1,840,842	411,555	2,252,397
October	2,035,286	402,948	2,438,234

b. Prepaid demand charges are calculated for Montana based on the contract demand for that jurisdiction. Prepaid commodity charges are allocated to Montana based on the ratio of Montana sales to total company sales, adjusted to reflect normal weather.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-065 RE: Statement E, Adjustment H - Pensions and benefits
Witness - Mulkern

Provide an explanation as to why this adjustment does not reflect the balance as of December 31, 2012 – and therefore an average of 2012 – as was done for other rate base components.

Response:

Montana-Dakota used the same method as used in prior case, which was a beginning and ending average.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-069 **RE: Statement E, Adjustment N - Customer advances for construction**
Witness: - Mulkern

Provide a schedule that shows the actual balance of customer advances for construction for each month from July 2012 through the most recent month available.

Response:

The balances are shown below:

July	$712,141
August	751,368
September	751,368
October	759,139

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-070 RE: Statement B
Witness - Mulkern

The income statement shows Revenues from Merchandising, Jobbing and Contract Work and the Costs and Expenses associated with these activities that net to $1,389,701.

a. Provide a detailed description of all such services provided.

b. Provide all supporting documentation and detail that shows the revenues and expenses associated with these services are booked "below the line" and are not included in the revenue requirement in this case.

c. Provide a schedule that shows the revenues and expenses, by type of service, for the gas utility, and as allocated/assigned to Montana gas operations, on an actual basis for 2011 and for 2012 to date.

Response:

a. Please see Attachment A.
b. Please see Attachment A. All revenues and expense are below-the-line items and are recorded in FERC Account Nos. 415 and 416.
c. All of the revenues and expenses are below-the-line and none are included in the revenue requirement.

Montana-Dakota Utilities Co.
MCC-070

MCC-070- Revenues	Total Revenue	MT Gas Revenue	Total Revenue	MT Gas Revenue
	YTD	YTD	YTD	YTD
Account Description	October 2012	October 2012	December 2011	December 2011
		(1,163,329.76)		(1,505,940.75)
Service & Repair Labor Revenue	(245,098.37)	-	(500,579.90)	-
Service & Repair Materials Revenue	(127,165.22)	-	(234,127.47)	-
Residential Basic Serivce Agreement R	(4,118,766.03)	-	(5,414,230.79)	-
Residential Plus Package	530.73	-	185,624.45	-
Commercial Service Agreement Revenu	(75,050.00)	-	(90,060.00)	-
House Piping Revenue	(8,909.38)	-	(53.92)	-
Appliance Sales Revnue	-	-	(1,069.78)	-
HVAC	-	-	(1,817.53)	-
Total Revenue	(4,574,458.27)	(1,163,329.76)	(6,056,314.94)	(1,505,940.75)

Montana-Dakota Utilities Co.
MCC-070

MCC-070- Expense	Total Expense	MT Gas Expense	Total Expense	MT Gas Expense
	YTD	YTD	YTD	YTD
Account Description	October 2012	October 2012	December 2011	December 2011
Total Expense		778,332.35		1,160,382.92
0140-Vendor Products Warranty				
Straight Time	271.55	-	738.11	-
Premium Time	110.46	-	392.91	-
Incentive Compensation	25.44	-	81.69	-
Payroll Taxes	35.10	-	92.79	-
Other Benefits	1.90	-	2.60	-
Medical/Dental & Life Insurance	26.56	-	110.12	-
Pension	(3.36)	-	20.63	-
Post Retirement	11.50	-	28.90	-
401 K Plan	46.09	-	106.98	-
Workers Compensation	5.79	-	14.49	-
Subcontract Labor	-	-	3,939.32	-
Materials	(202.23)	-	(526.30)	-
Company Vehicles	56.24	-	107.74	-
Reimbursements	(2,428.18)	-	(8,225.94)	-
0141-Service Warranty				
Straight Time	1,086.68	-	3,427.90	-
Premium Time	941.63	-	2,410.44	-
Incentive Compensation	136.82	-	444.54	-
Payroll Taxes	174.71	-	509.59	-
Other Benefits	6.93	-	12.09	-
Medical/Dental & Life Insurance	128.19	-	491.71	-
Pension	(12.57)	-	158.16	-
Post Retirement	54.75	-	105.31	-
401 K Plan	227.10	-	359.53	-
Workers Compensation	30.20	-	82.47	-
Contract Labor	-	-	1.22	-
Subcontract Labor	324.37	-	309.13	-
Materials	1,939.44	-	1,853.85	-
Company Vehicles	239.26	-	1,310.04	-
	-	-	300.89	-
0144-Damage to Customer Premises				
	75.00	-	583.50	-
0151-Reserve for Inventory Shrinkage				
	3,434.19	-	(1,074.50)	-
0430-Labor & Other Service & Repair Exp				
Straight Time	79,002.01	-	156,756.56	-
Premium Time	23,529.59	-	65,718.82	-
Incentive Compensation	6,918.13	-	16,902.28	-
Taxable Meals	11.68	-	48.80	-
Payroll Taxes	8,934.47	-	19,133.56	-
Other Benefits	505.68	-	501.94	-
Medical/Dental & Life Insurance	10,921.15	-	20,413.44	-
Pension	(1,082.69)	-	5,179.76	-
Post Retirement	3,756.09	-	4,538.21	-
401 K Plan	12,086.40	-	16,197.79	-
Workers Compensation	1,359.74	-	2,699.09	-

Montana-Dakota Utilities Co.
MCC-070

MCC-070- Expense	Total Expense	MT Gas Expense	Total Expense	MT Gas Expense
	YTD	YTD	YTD	YTD
Account Description	October 2012	October 2012	December 2011	December 2011
Contract Labor	-	-	(189.94)	-
Subcontract Labor	429.48	-	1,737.58	-
Materials	78,821.74	-	156,850.77	-
Company Vehicles/Work Equip	1,511.47	-	2,576.41	-
Company Vehicles	13,541.28	-	26,696.42	-
Company Work Equipment	75.00	-	36.00	-
Meals & Entertainment	46.27	-	-	-
Fees, Permits, Dues	348.00	-	289.00	-
Permits & Filing Fees	223.92	-	147.38	-
Reimbursements	-	-	(331.91)	-
Freight	877.46	-	1,509.43	-
Reference material	-	-	20.84	-
0431-Repair Parts Warehousing				
Straight Time	21,266.07	-	37,117.07	-
Premium Time	330.41	-	312.15	-
Incentive Compensation	1,459.51	-	2,853.65	-
Payroll Taxes	1,792.94	-	3,031.33	-
Other Benefits	139.27	-	128.98	-
Medical/Dental & Life Insurance	5,075.33	-	8,962.77	-
Pension	(371.51)	-	1,774.04	-
Post Retirement	1,421.21	-	1,107.22	-
401 K Plan	2,840.60	-	4,201.39	-
Workers Compensation	73.85	-	130.31	-
Company Vehicles	734.85	-	794.62	-
Commercial Air Service	180.42	-	423.96	-
Meals & Entertainment	57.29	-	863.75	-
Other Reimburseable Exp	66.23	-	716.96	-
Cellular Telephone	70.81	-	95.00	-
Office Supplies	2.38	-	289.79	-
Professional Organizational dues	128.50	-	174.00	-
Seminars and Meeting Registrations	-	-	35.50	-
0441-Residential Service Agreement				
Materials	170.81	-	16.18	-
04411-Residential Basic Service Agreement				
Straight Time	414,773.26	-	751,656.97	-
Premium Time	201,059.83	-	368,186.84	-
Incentive Compensation	41,554.79	-	84,207.95	-
Taxable Meals	22.73	-	445.05	-
Payroll Taxes	53,444.29	-	95,179.47	-
Other Benefits	2,737.66	-	2,510.69	-
Medical/Dental & Life Insurance	58,924.68	-	100,826.74	-
Pension	(5,105.83)	-	26,927.38	-
Post Retirement	20,855.23	-	22,653.98	-
401 K Plan	72,956.51	-	86,619.18	-
Workers Compensation	7,433.63	-	12,961.51	-
Contract Labor	357.49	-	486.32	-
Subcontract Labor	943.50	-	1,134.39	-
Materials	191,435.72	-	352,260.62	-
Company Vehicles/Work Equip	6,310.20	-	11,607.88	-
Company Vehicles	87,090.58	-	147,486.01	-

Montana-Dakota Utilities Co.
MCC-070

MCC-070- Expense	Total Expense	MT Gas Expense	Total Expense	MT Gas Expense
	YTD	YTD	YTD	YTD
Account Description	October 2012	October 2012	December 2011	December 2011
Personal Vehicle use	4.44	-	-	-
Meals & Entertainment	9.41	-	1,160.31	-
Freight	712.34	-	1,813.80	-
0450-Serve & Repair Supervision & Dispatching				
Straight Time	566,394.48	-	690,678.43	-
Premium Time	10,108.83	-	9,952.38	-
Bonuses & Commissions	8,361.98	-	39,118.79	-
Incentive Compensation	38,326.16	-	38,798.35	-
Moving Allowance	720.00	-	4,785.08	-
Taxable Meals	95.52	-	198.12	-
Payroll Taxes	54,394.74	-	65,309.63	-
Other Benefits	3,619.24	-	2,933.75	-
Vacation & Other Non-Productive Time	-	-	4,437.00	-
Medical/Dental & Life Insurance	91,556.90	-	110,908.22	-
Pension	(4,501.10)	-	15,149.61	-
Post Retirement	22,641.90	-	13,029.01	-
401 K Plan	58,826.65	-	71,536.65	-
Workers Compensation	1,268.85	-	1,664.15	-
Subcontract Labor	3,381.83	-	28,259.55	-
Consulting Services	120.00	-	-	-
Custodial Services & Supplies	2,181.24	-	2,261.99	-
Company Vehicles	7,350.29	-	7,336.70	-
Commercial Air Service	1,914.51	-	4,672.21	-
Corporate Aircraft	27.52	-	-	-
Personal Vehicle use	144.51	-	156.44	-
Meals & Entertainment	1,735.54	-	4,889.51	-
Other Reimburseable Exp	5,127.81	-	5,105.96	-
Telephone	24,668.39	-	18,019.35	-
Cellular Telephone	65,545.14	-	75,259.55	-
Network Circuit Charges	3,516.22	-	-	-
Office Supplies	2,447.50	-	3,293.48	-
Utilities	1,729.68	-	2,238.93	-
Postage	1,196.37	-	1,212.89	-
Professional Organizational dues	18.90	-	66.30	-
Misc. Employee Benefits	1,228.99	-	420.45	-
Seminars and Meeting Registrations	1,199.28	-	893.88	-
Other Employee Training	98.40	-	807.25	-
Software Maintenance	7,159.37	-	9,546.36	-
Rents	53,824.67	-	77,394.15	-
Reference Material	14.28	-	13.36	-
0460-Serve & Repair Allocable Expenses				
Straight Time	289,820.81	-	337,435.17	-
Premium Time	30,917.79	-	41,978.30	-
Bonuses & Commissions	8,513.79	-	11,397.26	-
Incentive Compensation	21,445.01	-	(28,065.66)	-
Taxable Meals	14.12	-	364.16	-
Payroll Taxes	27,818.02	-	29,706.02	-
Other Benefits	1,267.78	-	2,616.99	-
Vacation & Other Non-Productive Time	-	-	13,952.00	-
Medical/Dental & Life Insurance	38,648.18	-	43,867.81	-

Montana-Dakota Utilities Co.
MCC-070

MCC-070- Expense	Total Expense	MT Gas Expense	Total Expense	MT Gas Expense
	YTD	YTD	YTD	YTD
Account Description	October 2012	October 2012	December 2011	December 2011
Pension	(3,871.03)	-	3,840.60	-
Post Retirement	15,864.78	-	4,510.39	-
401 K Plan	39,431.68	-	29,438.10	-
Workers Compensation	3,140.56	-	2,543.69	-
Materials	1,489.22	-	1,997.21	-
Company Vehicles/Work Equip	1,162.97	-	1,795.44	-
Company Vehicles	9,294.98	-	16,112.55	-
Company Work Equipment	(41.58)	-	16.00	-
Personal Vehicle use	34.75	-	20.49	-
Meals & Entertainment	370.62	-	501.16	-
Other Reimburseable Exp	1,094.38	-	1,366.05	-
Office Supplies	2,492.01	-	2,726.84	-
Cellular Telephone	34,236.67	-	55,566.62	-
Office Supplies	184.24	-	349.40	-
Postage	30.26	-	77.30	-
Professional Organizational dues	-	-	8.73	-
Employee Training	-	-	49.56	-
Seminars and Meeting Registrations	187.04	-	4.21	-
Other Employee Training	16.04	-	-	-
Uniforms	6,483.02	-	8,690.34	-
Fees, Permits, Dues	110.00	-	200.00	-
Freight	13.10	-	11.61	-
0721- Commissions & Bonuses				
	6,706.00	-	17,120.00	-
Payroll Taxes	698.78	-	1,766.88	-
Workers Compensation	13.67	-	50.90	-
0749- Service & Repair Advertising				
Merchandise Promotion	1,696.87	-	1,322.36	-
Merchandise Advertising	8,349.40	-	47,604.66	-
0810- Region Accounting and Collections				
Collection Agency Fees	9,049.98	-	9,421.82	-
Company Vehicles/Work Equip	94.50	-	-	-
0820- Uncollectible Accts - Trade Ally Financing				
Uncollectible Accounts Exp	-	-	1,166.49	-
0821- Uncollectible Accts				
Uncollectible Accounts Exp	4,119.71	-	13,286.01	-
0851-Provision for Depreciation				
Depreciation - non utility	1,909.44	-	3,089.28	-
0852-Office Expense				
Custodial Services & Supplies	-	-	5.96	-
0930-Corporate Overhead				
Contract Labor	4,677.09	-	9,236.06	-
Subcontract Labor	17,118.08	-	32,362.02	-
Total Expense	3,060,567.18	778,332.35	4,666,614.16	1,160,382.92

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-071 RE: Statement B
Witness - Mulkern

The income statement shows Gain on the Disposition of Property in the amount of $228,379 and a Loss on the Disposition of Property in the amount of $(4,772). Provide all work papers, analyses, memos and other documentation related to the gain and loss shown.

Response:

Please see below the gains and losses on the disposition of property. The total loss of a negative $4,772 reflects the balance of several tools in Service and Repair under the Non-Utility sector where the gains exceeded losses for all pieces of equipment.

Montana-Dakota Utilities Co.
Gain / Loss as of 12/31/2011

Work Order Number	Description of Property	Amount	Utility
Gain			
188018	Glendive Service Center Land	$228,379.03	Common
Loss			
162901	Service and Repair Tools	($4,772.32)	Non-Utility

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-072 RE: All statements
Witness - As required

Provide a CD with each of statements in computer readable format - presumably in Excel, with all formulae intact.

Response:

Please see the enclosed CD for the electronic copies of Statements A-M and O, Exhibits TAA-3, JSG-2, RAM-1, RAM-2, EMR-3, and Interim Statements A-K, M, and O.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-074 RE: Last General Natural Gas Case Increase
Witness: David L. Goodin

In reference to your testimony at page 7, lines 14-16: In contrast to the 1 percent increase that was effective in January, 2005, what was the percentage increase that MDU requested in that case?

Response:

In Docket No. D2004.4.50, filed on April 1, 2004, Montana-Dakota requested an increase of 1.82 percent.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-079 RE: Debt to Equity Ratio
Witness: Garret Senger

In your testimony at page 5, lines 20-22: Please state the target date for achieving the targeted year end 50/50 debt to equity ratio.

Response:

The Company targets a 50/50 debt to equity ratio with a special emphasis on the December 31 balance.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-080 RE: Targeted Capital Structure at December 31, 2012
Witness: Garret Senger

In regard to your testimony at page 6, lines 14-18: Please provide a work paper showing that the anticipated $25 million common equity addition will achieve the targeted 50/50 year end capital structure at December 31, 2012.

Response:

Please see Attachment A.

MONTANA DAKOTA UTILITIES CO. AND
GREAT PLAINS NATURAL GAS CO.
MONTHLY CAPITAL STRUCTURE DETAIL

C:\Documents and Settings\HahnC\Local Settings\Temporary Internet Files\Content.Outlook\9UN4MZIG\[12_MDU_Cap_Struct_Detail xlsm.xlsm]Monthly (Year 1)

3-Dec-12

	Jan 2012	Feb 2012	Mar 2012	Apr 2012	May 2012	Jun 2012	Jul 2012	Aug 2012	Sep 2012	Oct 2012	Nov 2012	Dec 2012	Year 2012
EQUITY:													
Beginning Balance	$357,676	$363,606	$363,104	$365,692	$367,271	$360,672	$362,869	$366,338	$362,137	$365,547	$392,954	$390,336	$357,676
Earnings	5,930	6,098	2,588	1,580	(5)	2,197	3,469	2,775	3,410	2,407	4,545	6,530	41,524
Common Dividends Declared	0	(6,600)	0	0	(6,594)	0	0	(6,976)	0	0	(7,164)	0	(27,334)
Equity Infusion	0	0	0	0	0	0	0	0	0	25,000	0	0	25,000
Ending Balance	$363,606	$363,104	$365,692	$367,271	$360,672	$362,869	$366,338	$362,137	$365,547	$392,954	$390,336	$396,866	$396,866
LONG-TERM DEBT (Incl. Commercial Paper):													
Beginning Balance	$280,889	$280,888	$280,888	$280,887	$280,886	$280,886	$287,885	$308,418	$330,919	$347,021	$348,171	$367,780	$280,889
Issuance	0	0	0	0	0	0	0	0	0	0	0	0	0
Commerical Paper Changes	0	0	0	0	0	7,000	20,534	22,502	16,102	1,151	19,610	11,031	97,929
Retirements	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(101)	(108)
Ending Balance	$280,888	$280,888	$280,887	$280,886	$280,886	$287,885	$308,418	$330,919	$347,021	$348,171	$367,780	$378,710	$378,710
PREFERRED STOCK:													
Beginning Balance	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000
Issuance	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000	$15,000
TOTAL CAPITAL:	**$659,494**	**$658,991**	**$661,579**	**$663,158**	**$656,558**	**$665,754**	**$689,756**	**$708,056**	**$727,568**	**$756,125**	**$773,116**	**$790,576**	**$790,576**
CAPITAL STRUCTURE:													
EQUITY	55.1%	55.1%	55.3%	55.4%	54.9%	54.5%	53.1%	51.1%	50.2%	52.0%	50.5%	50.2%	
DEBT	42.6%	42.6%	42.5%	42.4%	42.8%	43.2%	44.7%	46.7%	47.7%	46.0%	47.6%	47.9%	
PREFERRED STOCK	2.3%	2.3%	2.2%	2.2%	2.3%	2.3%	2.2%	2.2%	2.1%	2.0%	1.9%	1.9%	
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-082 RE: MDU Resources
Witness: Stephen Gaske

Please provide a copy of MDU Resources Group, Inc., 2011 SEC Form 10-K, as referenced on footnotes 1-6 of your testimony.

Response:

Please see Response No. 52, Attachment A.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-083 RE: MDU Resources
Witness: Stephen Gaske

In reference to your testimony at page 5, lines 4-5: What percentage of MDU Resources' 2011 annual revenue and year end assets was accounted for by the aggregates and construction materials business?

Response:

According to MDU Resources Group, Inc.'s 2011 SEC Form 10-K, the construction materials and contracting segment accounted for 37.27 percent of total external operating revenues and 20.96 percent of total assets for 2011. (See pages 80 and 82 of MDU Resources Group, Inc.'s 2011 SEC Form 10-K)

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-084 RE: MDU's Montana Customer Growth
Witness: Stephen Gaske

In reference to your testimony at page 6, lines 11-13: Please provide a comparison of MDU's Montana customer base growth and customer growth for your selected proxy group of natural gas distribution companies during the past three years.

Response:

Please see Attachment A.

	NATURAL GAS DISTRIBUTION CUSTOMERS					
	2008	2009	2010	2011	CAGR	Source
Montana-Dakota Utilities Co. (MT)	77,090	77,750	78,450	79,118	0.87%	[1]
AGL Resources Inc.	2,273,000	2,266,000	2,264,000	4,454,000	25.14%	[2]
Atmos Energy Corporation	3,105,418	3,094,545	3,102,029	3,129,438	0.26%	[3]
Laclede Group, Inc.	629,190	629,563	627,393	625,077	-0.22%	[4]
New Jersey Resources Corporation	483,487	486,529	490,310	494,883	0.78%	[5]
Northwest Natural Gas Company	662,341	667,794	673,997	679,543	0.86%	[6]
Piedmont Natural Gas Company, Inc.	949,605	952,469	960,801	968,188	0.65%	[7]
South Jersey Industries, Inc.	340,136	343,566	347,725	351,304	1.08%	[8]
Southwest Gas Corporation	1,819,000	1,824,000	1,837,000	1,859,000	0.73%	[9]

Notes:

[1] Annual Report of Montana-Dakota Utilities Co. to the Montana Public Service Commission, at Schedule 29
[2] AGL Resources Inc, Form 10-K for the fiscal year ended December 31, 2011, at 37
AGL Resources Inc, Form 10-K for the fiscal year ended December 31, 2010, at 32
[3] Atmos Energy Corporation, Form 10-K for the fiscal year ended September 30, 2011, at 10
[4] The Laclede Group, Inc., Form 10-K for the fiscal year ended September 30, 2011, at 9
The Laclede Group, Inc., Form 10-K for the fiscal year ended September 30, 2010, at 10
[5] New Jersey Resources Corporation, Form 10-K for the fiscal year ended September 30, 2011, at 24
[6] Northwest Natural Gas Company, Form 10-K for the fiscal year ended December 31, 2011, at 49
Northwest Natural Gas Company, Form 10-K for the fiscal year ended December 31, 2010, at 48
[7] Piedmont Natural Gas Company, Inc., Form 10-K for the fiscal year ended October 31, 2011, at 3
[8] South Jersey Industries, Inc., Form 10-K for the fiscal year ended December 31, 2011, at 28
South Jersey Industries, Inc., Form 10-K for the fiscal year ended December 31, 2010, at 27
[9] Southwest Gas Corporation, Form 10-K for the fiscal year ended December 31, 2011, at 20

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-085 RE: Interest Rates and the Economy
Witness: Stephen Gaske

Please provide copies of the Blue Chip Economic Indicators, Volume 37, No. 3, March 2012, and the Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14, as referenced in your testimony at footnote 7, page 11 and footnote 10, page 12, respectively.

Response:

Please see Attachment A for the March 2012 report and Attachment B for the June 2012 report.

Response No. MCC-085
Attachment A

Blue Chip Economic Indicators®

Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead

Vol. 37, No. 3 March 10, 2012

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Law & Business

BLUE CHIP ECONOMIC INDICATORS®

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TABLE OF CONTENTS

Summary -- Highlights of latest survey results ..... **p. 1**

2012 Blue Chip Forecasts -- Individual and consensus forecasts of annual change in 15 key U.S. economic variables ..... **p. 2**

2013 Blue Chip Forecasts – Individual and consensus forecasts of annual change in 15 key U.S. economic variables ..... **p. 3**

History of Annual Consensus Forecasts -- Annual forecasts from January 2011 to present and selected graphs ..... **p. 4**

Quarterly Blue Chip Forecasts -- Consensus forecasts of quarterly change in 12 U.S. economic variables through the end of 2013 ..... **p. 5**

Blue Chip International Forecasts -- 2012 and 2013 consensus forecasts of economic growth, inflation, current account, exchange rate and short-term interest rate for 15 of America's largest trading partners ..... **p. 6-7**

Recent Developments -- Graphs and analysis of economic trends ..... **p. 8-9**

Quarterly U.S. Forecasts -- Graphs and analysis of latest quarterly consensus forecasts of key U.S. economic variables ..... **p. 10-11**

International Forecasts -- Graphs and analysis of selected international consensus forecasts ..... **p. 12**

Databank -- Monthly historical data on many key indicators of economic activity ..... **p. 13**

Special Questions -- Results of twice-annual long-range survey. Consensus forecasts for the five years 2014 through 2018 and the five-year period 2019-2023 ..... **p. 14-15**

Viewpoints -- A sampling of views on the economy and government excerpted from recent reports issued by our panel members or others .... **p. 16-17**

Calendar -- Release dates for important upcoming economic data, FOMC meetings, etc ..... **p. 18**

Very Modest Changes In Outlook Since Last Month

Domestic Commentary The consensus forecast of year-to-year (y/y) real GDP growth in 2012 inched up 0.1 of a percentage point to 2.3% this month, according to our March 5th-6th survey, the first increase since early December. However, the consensus forecast of y/y growth in 2013 went unchanged at 2.6% as did the forecasts that real GDP would expand 2.3% and 2.8%, respectively, on a fourth quarter-over-fourth quarter (q4/q4) basis this year and next. Also unchanged were consensus forecasts of seasonally-adjusted annual growth (saar) in real GDP from Q1 2012 through Q4 2013. The consensus still predicts that real GDP growth in the first half of this year will fall a bit short of the 2.4% (saar) registered in the second half of 2011. Growth in the second half of 2012, however, is forecast to slightly exceed that witnessed in the second half of last year. Not until the second half of 2013 does the consensus predict that real GDP growth will exceed its trend rate. Moreover, real GDP growth is not forecast to match or exceed the 3.0% pace witnessed in the final quarter of last year until Q4 2013. Although the consensus predicts that the unemployment rate will continue to decline, its rate of descent may slow due to the still-modest rate of GDP growth and a rebound in the labor force participation rate. Consensus forecasts of consumer price inflation also inched up this month, most likely the result of surging gasoline prices. Nonetheless, the vast majority of our panelists continue to forecast that inflation is likely to remain relatively benign this year and next.

The stabilization and then gradual improvement in consensus forecasts of real GDP growth in 2012 since late last fall has resulted from a generally steady diet of better-than-expected high-frequency reports on U.S. economic activity, a strong rebound in U.S. equity prices that lifted household wealth, narrowing credit spreads, and easing concerns about the Eurozone crisis. Nonetheless, a variety of concerns have prevented our panelists from becoming even more optimistic. While real GDP growth in Q4 2011 was an upwardly revised 3.0%, the best since Q2 2010, the mix of growth was disappointing with a surge in business inventories accounting for about two-thirds of the increase. Some panelists also worry that an unseasonably warm and dry winter in much of the nation has overwhelmed seasonal-adjustment factors. As a result, some recent high-frequency measures of economic activity may be overstating the economy's current strength. The recent surge in gasoline prices also is a worry. The potential for sluggish growth if not outright recessions in the U.K. and the Eurozone also remain a threat to U.S. exports. The outlook for 2013 is particularly cloudy. Absent Congressional action before the end of this year all of the Bush-era tax cuts will expire, the current reduction in workers' payroll taxes will end, and large automatic cuts in defense and domestic spending will kick in. Contemplation of how a lame-duck Congress, and possibly lame-duck President, will handle this looming fiscal train wreck does not inspire confidence.

As for the trajectory of economic growth this year, real GDP still is forecast by the consensus to increase 2.1% (saar) in Q1, 2.2% in Q2, 2.4% in Q3 and 2.6% in Q4. Forecasts of quarterly growth in 2013 were also unchanged at 2.5% in Q1, 2.7% in Q2, 2.9% in Q3 and 3.0% in Q4. The consensus forecast 2012 y/y growth in nominal (current dollar) GDP rebounded 0.1 of a point this month to 4.1%. Nominal GDP still is predicted to grow 4.6% in 2013.

Consensus forecasts of the average unemployment rate in 2012 and 2013 declined another 0.1 of a percentage point this month to 8.2% and 7.8%, respectively. The 2012 forecast has dropped 0.8 of a point since last November and the 2013 forecast 0.5 of a point since January of this year. Since hitting its peak in late 2009 the unemployment rate has fallen more than one would have expected given the historically modest nature of the recovery and expansion to date. The explanation is that the labor force participation rate also has continued to decline. If the participation rate began to rebound as discouraged workers re-entered the workforce, the fall in the jobless rate would slow.

The consensus forecasts that the GDP chained price index will post y/y and q4/q4 increases of 1.8% in 2012, 0.1 of a point more than last month. Next year it is predicted to increase 1.9% on a y/y basis and 2.0% measured q4/q4. That compares with a y/y and q4/q4 increases of 2.1% in 2011. The Consumer Price Index (CPI) is forecast by the consensus to register y/y and q4/q4 increases of 2.2% both this year and next. All increased slightly this month except for the forecast of the q4/q4 change in 2013.

As for the components of GDP growth over the forecast horizon, personal consumption expenditures (PCE) are expected to grow 2.0% on a y/y basis in 2012 and 2.3% in 2013. The forecast for this year slipped 0.1 of a point this month while the 2013 forecast was unchanged for a third consecutive month. Real PCE grew 2.1% (saar) in q4 2011, the best performance since the initial quarter of last year. However, real PCE registered no growth in November, December and January, suggesting consumer spending had little forward momentum going into 2012. The increase in real PCE last quarter was capped by a gain of only 0.7% in purchases of services as spending on electricity and natural gas fell due to unusually warm winter weather that sharply curtailed homeowners' heating bills. Indeed, consumer spending on electricity and natural gas has dropped each month since last August. Despite our panel's continued caution about consumer spending, consensus forecasts of auto and trucks sales increased for a third consecutive month, with sales now expected to average 14.3 million units this year and 14.8 million units in 2013 versus 12.7 million in 2011.

Modest growth in real disposable personal income (DPI) no doubt helps explain why the consensus has failed to become more upbeat about consumer spending over the forecast horizon. While second half 2011 growth in real DPI was recently revised higher its pace of expansion remained modest. Real DPI grew just 1.3% last year, 0.5 of a point less than in 2010. It is predicted to grow 1.5% in 2012. That is 0.2 of a point stronger than forecast last month but still a relatively modest increase. The consensus expects real DPI growth of 2.0% in 2013, 0.1 of a point less than forecast a month ago.

Real nonresidential fixed investment is forecast by the consensus to grow 7.3% y/y in 2012, 0.2 of a percentage point more than predicted a month ago and the highest level since December. That would still mark a deceleration from last year when it grew 8.7%. Next year real nonresidential fixed investment is forecast to grow 6.9%, also 0.2 of a point stronger than predicted a month ago. Consensus forecasts of growth in residential investment, in contrast, still are improving, although at a gradual rate. The consensus forecast of total housing starts in 2012 rose for a fourth straight month to 730,000 units and the forecast of total starts in 2013 increased to 890,000. That compares with total starts of 610,000 in 2011.

Real net exports and business inventories are expected to neither add nor subtract much from GDP growth this year and next. Exports will be hampered by slow growth abroad while modest growth in consumer spending and slower growth in capital spending will keep firms cautious about letting inventory levels get out of hand. Industrial production is forecast to register y/y increases of 3.6% this year and 3.3% in 2013. A contraction in government spending and investment subtracted a bit more than 0.4 of a percentage point from real GDP growth in 2011 and seems likely to remain a drag this year and next as local, state and federal authorities continue to grapple with budget deficits. The degree of fiscal tightening in 2013 remains an especially large wild card given the variety and size of the tax cuts set to expire at the end of this year.

International Commentary The consensus predicts Eurozone real GDP will contract -0.4% this year but grow 0.9% in 2013. The U.K.'s economy is forecast to grow 0.5% in 2012 and 1.7% in 2013.

Special Questions This issue contains our latest long-range survey results. On page 14 are estimates for 2014 through 2018 and an average for the five-year period 2019-2023. Page 15 compares the results with those of last October and the latest estimates from the Office of Management and Budget and the Congressional Budget Office.

GREEN indicates the Blue Chip consensus forecast of real GDP growth in the near-term is 3.0 percent or higher.
YELLOW cautions that the consensus forecast of real GDP growth in the near-term is between 1.0 percent and 3.0 percent.
RED warns that near-term consensus forecast of real GDP growth of real GDP growth in the near-term is below 1.0 percent.

2012 Real GDP Forecast Inches Up To 2.3%

MARCH 2012 Forecast For 2012 SOURCE:	Percent Change 2012 From 2011 (Full Year-Over-Prior Year)									Average For 2012			Total Units-2012		-2012-
	1 Real GDP (Chained) (2005 $)	2 GDP Price Index	3 Nominal GDP (Cur. $)	4 Consumer Price Index	5 Indust. Prod. (Total)	6 Dis. Pers. Income (2005 $)	7 Personal Cons. Exp (2005 $)	8 Non-Res. Fix. Inv. (2005 $)	9 Corp. Profits (Cur. $)	10 Treas. Bills 3-mo.	11 Treas. Notes 10-Year	12 Unempl. Rate (Civ.)	13 Housing Starts (Mil.)	14 Auto & Light Truck Sales (Mil.)	15 Net Exports (2005 $)
Naroff Economic Advisors*	2.9 H	2.6	5.6 H	3.2 H	3.0	2.4 H	2.7 H	7.0	6.8	0.2 H	2.2	8.1	0.69	14.6	-480.0 L
Action Economics	2.8	2.0	4.8	2.7	4.5	1.4	2.0	10.6	5.7	0.1	2.4	8.2	0.70	15.0	-396.0
Bank of Tokyo-Mitsubishi UFJ	2.7	2.3	5.0	2.9	3.0	2.0	2.6	8.0	9.0	0.2 H	2.7	7.9 L	1.00 H	14.7	-450.0
RDQ Economics	2.7	2.2	5.0	2.6	3.7	1.7	2.1	7.0	7.6	0.1	2.8 H	8.4	0.70	14.0	-398.8
AIG	2.6	1.0 L	3.6	1.1 L	3.7	0.9 L	1.4	15.1 H	8.3	0.1	2.3	8.5	0.80	14.6	-402.5
Barclays Capital	2.5	2.3	4.8	2.6	4.2	1.4	2.3	9.6	6.3	0.1	2.1	8.1	0.72	14.4	-395.0
Eaton Corporation	2.5	1.9	4.4	2.1	4.4	1.7	2.0	8.4	6.4	0.1	2.1	8.0	0.77	14.3	-399.4
Russell Investments	2.5	1.7	4.2	1.9	3.7	1.4	2.3	6.4	6.0	0.1	2.2	8.2	0.71	13.8	-406.0
Moody's Analytics	2.5	1.3	3.6	2.1	3.7	2.3	2.2	6.9	6.7	0.0 L	2.4	8.2	0.85	14.5	-420.4
Turning Points (Micrometrics)	2.4	2.1	4.5	2.0	3.4	1.1	1.9	6.7	7.2	0.0 L	2.0	7.9 L	0.71	14.6	-364.0 H
Wells Capital Management	2.4	2.0	4.4	2.3	3.4	2.0	2.2	9.6	4.8	0.2 H	2.4	8.2	0.67	14.2	-396.0
Northern Trust Company*	2.4	1.8	4.3	2.2	na	na	1.9	6.9	na	0.1	2.2	8.2	0.75	14.6	-435.0
BMO Capital Markets*	2.4	1.8	4.2	2.2	3.7	1.8	1.9	6.3	5.7	0.1	2.0	8.2	0.70	14.7	-395.0
Macroeconomic Advisers, LLC**	2.4	1.5	4.0	2.4	4.3	1.5	2.0	8.2	0.8	0.2 H	2.4	8.2	0.72	15.0	-386.2
Oxford Economics	2.3	1.9	4.3	2.2	3.8	1.7	2.0	7.2	5.6	0.0 L	2.2	8.4	0.74	14.4	-392.1
National Assn. of Realtors	2.3	2.3	4.6	2.9	3.3	2.1	1.9	8.2	7.5	0.0 L	2.1	8.1	0.76	14.0	-405.0
Pierpont Securities	2.3	2.1	4.5	2.6	4.0	1.5	1.9	8.3	6.5	0.1	2.4	8.1	0.84	14.8	-416.0
UBS	2.3	1.9	4.2	2.0	3.9	2.2	1.9	7.3	na	0.1	2.2	8.1	0.80	na	-449.8
DuPont***	2.3	1.9	4.2	2.5	3.7	1.5	2.1	7.0	6.0	0.1	2.3	8.2	0.70	13.9	-411.0
SOM Economics, Inc.	2.3	1.9	4.2	2.3	3.7	1.1	2.2	6.7	4.5	0.2 H	2.2	8.0	0.73	14.7	-406.0
PNC Financial Services Group	2.3	1.8	4.1	2.2	4.5	1.3	2.1	7.2	na	0.1	2.0	8.1	0.71	14.1	-413.4
Inforum - Univ. of Maryland	2.3	1.7	4.1	2.2	4.3	1.4	2.0	8.0	3.9	0.1	2.3	8.2	0.73	14.2	-411.0
ClearView Economics*	2.3	1.7	4.0	2.2	3.4	0.6	2.1	6.0	2.8	0.1	2.0	8.1	0.71	14.1	-427.0
RBS	2.3	1.7	4.0	2.4	3.3	1.7	1.9	8.5	8.0	0.1	2.0	8.1	0.85	14.2	-417.0
National Assn. of Home Builders	2.3	1.7	4.0	2.1	3.2	1.5	2.1	6.0	5.0	0.1	2.3	8.3	0.71	14.0	-400.0
Credit Suisse	2.3	1.7	3.9	2.1	3.6	na	1.9	7.0	6.5	na	1.9 L	8.1	0.65 L	na	-424.0
U.S. Chamber of Commerce	2.3	1.6	4.0	2.1	4.0	0.7	2.2	7.4	6.5	0.1	2.2	8.3	0.70	na	-417.4
MacroFin Analytics	2.3	1.5	3.8	2.0	3.6	1.6	2.0	7.1	5.7	0.1	2.2	8.2	0.66	13.5	-375.0
General Motors Corporation	2.3	1.4	3.8	1.8	2.3	1.6	2.2	6.1	8.9	0.2 H	2.4	8.5	0.74	na	-374.7
J P MorganChase	2.3	1.4	3.7	2.0	4.7 H	1.7	1.9	7.6	4.3	0.1	2.8 H	8.2	0.72	14.2	-417.2
Ford Motor Company*	2.2	2.7 H	4.9	2.8	3.9	0.3 L	2.0	8.2	na	0.1	2.2	8.3	0.73	na	-397.7
Kellner Economic Advisers	2.2	2.0	4.2	2.2	3.4	1.6	2.0	6.8	6.0	0.1	2.0	8.3	0.70	14.0	-410.0
Econoclast	2.2	2.0	4.2	2.1	3.5	1.6	2.0	7.5	6.2	0.1	2.0	8.2	0.71	13.9	-392.0
Morgan Stanley	2.2	2.0	4.2	2.1	3.4	1.6	1.9	6.9	2.7	0.0 L	2.0	8.3	0.68	13.8	-380.7
J.W. Coons Advisors	2.2	1.9	4.2	2.4	3.1	1.9	2.4	6.6	4.3	0.2 H	2.1	7.9	0.76	14.0	-419.0
Comerica	2.2	1.9	4.1	2.0	4.4	0.8	2.2	7.3	na	0.0 L	2.0	8.0	0.69	14.4	-426.0
Swiss Re	2.2	1.9	4.1	2.2	3.4	1.5	2.1	6.6	4.8	0.1	2.1	8.0	0.76	14.1	-387.6
Daiwa Capital Markets America	2.2	1.6	3.8	2.0	3.4	1.3	1.9	8.1	1.4	0.1	2.2	8.3	0.68	14.8	-434.0
Mesirow Financial	2.2	1.5	3.7	2.0	3.9	1.0	1.9	8.1	7.8	0.1	2.3	8.2	0.70	14.6	-399.0
Fannie Mae	2.2	1.5	3.7	2.0	3.8	0.9	2.1	7.3	6.0	0.1	2.0	8.3	0.71	14.5	-395.8
Nomura Securities	2.2	1.4	3.6	1.8	4.4	0.5	1.8	7.3	17.2 H	0.1	2.2	8.1	0.74	15.1 H	-388.1
UCLA Business Forecasting Proj.*	2.2	1.3	3.5	2.1	3.8	1.2	2.1	6.8	-0.4 L	0.1	2.2	8.4	0.73	13.8	-415.2
FedEx Corporation	2.1	1.9	4.0	2.3	3.9	1.5	1.8	7.0	5.9	0.1	2.4	8.4	0.73	14.5	-442.5
Wintrust Wealth Management*	2.1	1.8	4.0	2.2	3.1	2.2	2.2	7.0	7.3	0.1	2.2	8.2	0.70	14.0	-410.0
Standard & Poors Corp.*	2.1	1.2	3.3	2.0	3.7	1.2	2.0	6.7	2.7	0.0 L	2.2	8.4	0.73	13.6	-411.5
Moody's Capital Markets	2.0	1.8	3.8	2.4	3.8	1.4	2.0	5.0	5.0	0.1	2.1	8.3	0.71	14.7	-409.3
Citigroup U.S. Economics	2.0	1.5	3.5	2.4	3.6	2.2	1.9	6.8	4.4	0.1	2.2	8.1	0.78	13.8	-399.0
Goldman Sachs & Co.**	2.0	1.5	3.5	2.2	2.7	1.5	1.7	6.1	7.6	0.0 L	2.4	8.3	0.69	13.4 L	-398.6
Conference Board*	2.0	1.4	3.4	2.3	3.3	1.4	2.1	6.1	5.8	0.1	2.0	8.3	0.71	14.8	-395.6
Economist Intelligence Unit	1.9	2.4	4.3	2.3	3.4	2.0	2.2	5.6	na	0.0 L	2.1	8.1	0.72	13.8	-430.0
Wells Fargo	1.9	2.1	4.0	2.2	3.8	1.2	1.6	8.8	6.3	0.1	2.2	8.3	0.69	14.5	-431.2
Bank of America Merrill Lynch	1.9	1.5	3.4	2.2	3.0	na	1.8	5.5	na	0.1	2.4	8.4	0.71	14.1	-400.0
Georgia State University*	1.9	1.3	3.1 L	2.1	3.1	1.5	1.7	5.1	6.1	0.0 L	2.4	8.4	0.72	13.6	-394.8
RBC	1.8	2.4	4.2	2.4	1.9	na	2.1	6.7	na	0.1	2.0	9.0 H	0.65 L	13.4 L	-412.5
Societe Generale	1.6 L	1.9	3.6	2.2	1.5 L	1.3	1.8	4.3 L	2.0	0.0 L	2.0	8.5	0.67	14.4	-409.6
2012 Consensus: March Avg.	**2.3**	**1.8**	**4.1**	**2.2**	**3.6**	**1.5**	**2.0**	**7.3**	**5.8**	**0.1**	**2.2**	**8.2**	**0.73**	**14.3**	**-408.6**
Top 10 Avg.	2.6	2.3	4.8	2.7	4.3	2.1	2.3	8.6	8.8	0.2	2.5	8.5	0.82	14.8	-383.5
Bottom 10 Avg.	1.9	1.4	3.5	2.0	2.7	0.8	1.8	5.7	2.5	0.0	2.0	8.0	0.67	13.7	-440.6
February Avg.	2.2	1.7	4.0	2.1	3.4	1.3	2.1	7.1	5.8	0.1	2.2	8.3	0.72	14.0	-408.2
Historical data: 2008	-0.3	2.2	1.9	3.8	-3.7	2.4	-0.6	-0.8	-17.4	1.4	3.7	5.8	0.91	13.2	-494.8
2009	-3.5	1.1	-2.5	-0.4	-11.2	-2.3	-1.9	-17.8	9.1	0.2	3.2	9.3	0.55	10.4	-358.8
2010	3.0	1.2	4.2	1.6	5.3	1.8	2.0	4.4	32.2	0.1	3.2	9.6	0.59	11.6	-421.8
2011	1.7	2.1	3.9	3.2	4.2	1.3	2.2	8.7	na	0.1	2.8	9.0	0.61	12.7	-412.0
Number Of Forecasts Changed From A Month Ago:															
Down	10	5	8	4	6	9	25	17	20	6	18	19	5	3	17
Same	28	24	16	22	13	13	23	13	19	40	29	33	24	16	14
Up	17	26	31	29	33	29	7	25	6	8	8	3	26	31	24
March Median	2.3	1.8	4.1	2.2	3.7	1.5	2.0	7.0	6.0	0.1	2.2	8.2	0.71	14.2	-406.0
March Diffusion Index	56 %	69 %	71 %	73 %	76 %	70 %	34 %	57 %	34 %	52 %	41 %	35 %	69 %	78 %	56 %

*Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.

2013 Real GDP Forecast Remains At 2.6%

MARCH 2012 Forecast For 2013 SOURCE:	Percent Change 2013 From 2012 (Full Year-Over-Prior Year)									Average For 2013			Total Units-2013		-2013-
	1 Real GDP (Chained) (2005 $)	2 GDP Price Index	3 Nominal GDP (Cur. $)	4 Consumer Price Index	5 Indust. Prod. (Total)	6 Dis. Pers. Income (2005 $)	7 Personal Cons. Exp (2005 $)	8 Non-Res. Fix. Inv. (2005 $)	9 Corp. Profits (Cur. $)	10 Treas. Bills 3-mo.	11 Treas. Notes 10-Year	12 Unempl. Rate (Civ.)	13 Housing Starts (Mil.)	14 Auto & Light Truck Sales (Mil.)	15 Net Exports (2005 $)
Pierpont Securities	3.9 H	2.8	6.8 H	3.3	4.7	3.0	3.3 H	12.9 H	7.5	0.8	4.2 H	7.2	1.21	15.4	-443.0
AIG	3.4	0.4 L	3.8	0.5 L	3.8	3.3	2.5	11.1	3.9	0.1	2.9	8.2	1.04	15.5	-414.5
RDQ	3.2	2.9 H	6.2	3.3	3.4	2.4	2.8	6.9	6.2	0.1	3.8	8.0	0.90	14.5	-400.5
Naroff Economic Advisors*	3.2	2.7	5.9	3.1	3.2	3.0	3.3 H	7.1	6.4	0.6	3.0	7.3	0.76	15.1	-590.0 L
Action Economics	3.2	2.6	5.9	3.3	4.3	1.6	2.1	11.4	4.9	0.5	3.5	7.7	0.82	15.9	-369.0
Bank of Tokyo-Mitsubishi UFJ	3.2	2.5	5.7	2.8	4.0	2.0	3.2	9.0	9.0	1.0 H	3.4	7.1 L	1.20	16.0	-550.0
ClearView Economics*	3.0	2.4	5.4	2.7	3.5	1.6	2.7	6.8	7.1	0.1	2.0 L	7.3	0.75	14.6	-436.0
Ford Motor Company*	3.0	2.2	5.2	2.5	2.0	0.7	2.6	6.3	na	0.1	2.7	8.0	0.97	na	-372.6
Macroeconomic Advisers, LLC**	3.0	1.6	4.6	2.1	2.5	1.2	2.7	6.5	2.6	0.3	3.3	7.6	0.98	15.4	-363.4
Moody's Analytics	2.9	2.3	5.2	2.0	2.7	2.3	3.0	5.2	3.7	0.1	3.7	7.9	1.36 H	16.1	-474.5
Daiwa Capital Markets America	2.9	1.9	4.9	2.0	3.3	3.1	2.4	9.4	1.1	0.1	2.6	7.9	0.73	15.4	-445.0
General Motors Company	2.9	1.1	4.0	1.6	2.1	1.3	2.2	5.5	17.3 H	0.3	3.5	8.2	0.97	na	-321.0
National Assn. of Realtors	2.8	2.5	5.3	3.5 H	3.2	2.4	2.2	9.8	4.5	0.2	2.7	7.6	0.96	14.2	-413.0
Comerica	2.8	2.2	5.1	2.0	4.5	2.2	2.5	8.0	na	0.0 L	2.0 L	7.2	0.74	15.0	-432.0
Kellner Economic Advisers	2.8	2.1	4.9	2.3	3.5	2.2	2.2	7.0	8.5	0.2	2.8	7.8	0.84	14.8	-420.0
DuPont***	2.8	2.0	4.9	2.0	3.7	2.8	2.5	6.4	6.0	0.5	3.4	7.8	1.03	14.8	-405.0
Inforum - Univ. of Maryland	2.8	1.9	4.8	2.3	3.6	1.5	2.2	6.1	2.3	0.4	3.1	7.8	0.79	14.1	-399.0
Eaton Corporation	2.8	1.5	4.3	1.9	4.0	2.7	2.3	8.6	6.5	0.2	2.4	7.1 L	0.96	14.9	-401.2
National Assn. of Home Builders	2.8	1.4	4.2	1.7	3.5	2.2	2.3	5.5	6.5	0.3	3.1	8.1	0.90	14.5	-370.0
Wells Capital Management	2.7	2.2	4.9	2.5	3.2	2.6	2.5	7.9	4.2	0.4	3.4	7.6	0.70	14.1	-412.0
Nomura Securities	2.7	2.0	4.8	1.3	4.6	2.6	2.4	6.2	3.8	0.1	2.5	7.6	0.90	16.4 H	-351.4
Wintrust Wealth Management*	2.7	2.0	4.7	2.3	3.3	2.3	2.4	6.8	6.5	0.2	3.0	7.9	0.86	14.9	-407.0
BMO Capital Markets*	2.7	1.9	4.7	2.1	3.5	1.6	2.6	7.1	4.8	0.1	2.9	7.7	0.74	15.0	-379.0
Swiss Re	2.7	1.8	4.6	2.0	3.0	2.7	2.5	6.7	6.6	0.1	2.6	7.4	0.92	14.9	-406.6
Moody's Capital Markets	2.7	1.8	4.6	2.1	3.6	2.4	2.7	4.7	5.1	0.1	2.7	7.8	0.82	15.3	-391.9
U.S. Chamber of Commerce	2.7	1.8	4.5	2.2	3.7	2.3	2.7	7.0	6.3	0.2	2.8	8.2	0.73	na	-448.3
Oxford Economics	2.7	2.5	5.3	2.1	3.4	2.3	2.6	7.8	7.8	0.0 L	2.9	7.5	1.10	14.8	-411.7
RBS	2.6	2.1	4.8	2.3	2.5	3.0	2.1	7.8	9.0	0.1	2.0 L	7.6	1.10	14.5	-412.0
PNC Financial Services Group	2.6	2.1	4.7	2.3	3.9	2.1	2.4	5.0	na	0.1	2.5	7.7	0.78	14.2	-433.2
UBS	2.6	2.0	4.7	1.8	4.9 H	2.4	2.4	10.1	na	0.5	2.7	7.5	0.90	na	-517.3
MacroFin Analytics	2.6	1.3	4.0	2.0	3.3	2.2	2.3	7.0	5.0	0.2	2.5	7.7	0.68 L	13.5 L	-360.0
Barclays Capital	2.5	2.7	5.3	2.7	4.5	3.5 H	2.6	10.7	na	na	na	7.3	0.85	na	-406.0
Turning Points (Micrometrics)	2.5	2.0	4.5	2.2	3.4	1.1	2.0	5.1	6.8	0.1	2.4	7.3	0.81	15.4	-292.4 H
FedEx Corporation	2.4	2.1	4.4	2.3	3.4	2.2	2.6	5.9	6.3	0.1	3.2	8.0	0.88	14.7	-477.5
Russell Investments	2.4	2.0	4.4	2.0	3.4	2.3	2.5	5.3	5.0	0.2	2.8	7.7	0.78	14.3	-409.0
Conference Board*	2.4	1.2	3.6	2.0	2.8	2.2	2.5	7.4	4.1	0.1	2.3	7.9	0.76	15.2	-405.8
UCLA Business Forecasting Proj.*	2.3	1.4	3.8	2.0	3.0	1.6	2.0	6.2	-0.7	0.2	3.1	8.1	0.98	14.7	-370.7
Georgia State University*	2.3	1.4	3.8	1.5	2.8	1.6	1.9	5.7	8.4	0.1	2.9	8.2	0.85	13.9	-336.4
Fannie Mae	2.3	1.4	3.7	1.7	2.7	0.6	2.1	5.5	4.2	0.3	2.3	8.1	0.88	15.0	-369.6
Mesirow Financial	2.3	1.3	3.7	1.8	1.4	1.2	1.8	6.6	14.3	0.3	3.3	7.8	0.97	14.8	-410.9
Standard & Poors Corp.*	2.3	1.3	3.7	1.8	3.0	1.5	2.1	6.0	8.5	0.1	2.7	8.2	0.99	14.7	-368.7
Wells Fargo	2.2	2.1	4.3	2.2	2.3	1.0	1.3	5.5	-6.6 L	0.2	2.3	8.3	0.80	14.2	-385.8
Econoclast	2.2	2.1	4.3	2.2	3.3	1.5	1.9	6.5	6.0	0.2	2.6	7.8	0.83	14.4	-385.0
J P MorganChase	2.2	1.4	3.6	1.5	3.2	2.3	1.8	6.4	5.0	na	na	8.0	0.80	14.0	-418.4
Goldman Sachs & Co.**	2.2	1.3	3.5 L	1.7	3.7	1.8	1.9	7.0	7.9	0.0 L	2.9	8.2	0.83	14.6	-419.3
Economist Intelligence Unit	2.1	2.3	4.4	2.2	3.4	1.9	2.2	5.7	na	0.1	2.3	7.8	0.90	14.2	-464.0
J.W. Coons Advisors	2.1	2.2	4.4	2.5	1.9	2.4	2.2	4.0	8.1	0.8	2.5	7.5	0.99	14.2	-418.0
SOM Economics, Inc.	1.8	2.1	3.9	2.3	2.7	1.4	2.0	3.8 L	1.5	0.2	2.3	7.6	0.80	15.0	-410.0
Citigroup U.S. Economics	1.8	2.0	3.8	1.8	3.2	0.3	1.8	5.2	0.4	0.1	2.7	8.0	0.95	14.0	-394.0
Morgan Stanley	1.8	1.9	3.8	1.8	3.2	1.3	1.4	5.3	-0.5	0.0 L	2.0 L	8.3	0.75	13.9	-340.0
Societe Generale	1.7 L	2.0	3.8	1.7	0.9 L	-0.3 L	1.0 L	5.4	5.1	0.0 L	2.3	8.7 H	0.77	14.8	-347.5
2013 Consensus: March Avg.	**2.6**	**1.9**	**4.6**	**2.2**	**3.3**	**2.0**	**2.3**	**6.9**	**5.5**	**0.2**	**2.8**	**7.8**	**0.89**	**14.8**	**-407.4**
Top 10 Avg.	3.1	2.5	5.6	2.8	4.2	2.9	2.8	9.3	9.7	0.5	3.5	8.3	1.07	15.5	-345.0
Bottom 10 Avg.	2.0	1.3	3.7	1.6	2.1	0.8	1.7	4.9	0.8	0.1	2.2	7.3	0.73	14.0	-472.9
February Avg.	2.6	1.9	4.6	2.1	3.2	2.1	2.3	6.7	5.9	0.2	2.9	7.9	0.88	14.6	-400.6
Number Of Forecasts Changed From A Month Ago:															
Down	15	7	13	10	10	16	16	10	13	12	14	21	8	9	22
Same	24	29	22	28	28	21	21	23	21	29	25	27	26	18	9
Up	12	15	16	13	12	14	14	18	9	8	10	3	17	19	20
March Median	2.7	2.0	4.6	2.1	3.3	2.2	2.4	6.5	6.0	0.2	2.7	7.8	0.86	14.8	-406.6
March Diffusion Index	47 %	58 %	53 %	53 %	52 %	48 %	48 %	58 %	45 %	46 %	46 %	32 %	59 %	61 %	48 %

***Former winner of annual Lawrence R. Klein Award for Blue Chip Forecast Accuracy. **Denotes two-time winner. ***Denotes three-time winner.**

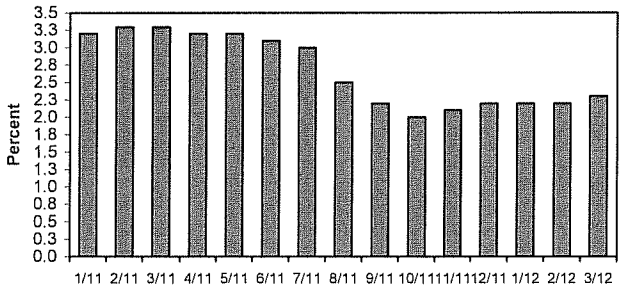
BASIC DATA SOURCES: [1]Gross Domestic Product (GDP), chained 2005$, National Income and Product Accounts (NIPA), Bureau of Economic Analysis (BEA); [2]GDP Chained Price Index, NIPA, BEA; [3]GDP, current dollars, NIPA, BEA; [4]Consumer Price Index-All Urban Consumers, Bureau of Labor Statistics (BLS); [5]Total Industrial Production, Federal Reserve Board (FRB); [6]Disposable Personal Income, 2005$, NIPA, BEA; [7]Personal Consumption Expenditures, 2005$, NIPA, BEA; [8]Non-residential Fixed Investment, 2005$, NIPA, BEA; [9]Corporate Profits Before Taxes, current dollars, with inventory valuation and capital consumption adjustments, NIPA, BEA; [10]Treasury Bill Rate, 3-month, secondary market, bank discount basis, FRB; [11]Treasury note yield, 10-year, constant maturity basis, FRB; [12]Unemployment Rate, civilian work force, BLS; [13]Housing Starts, Bureau of Census; [14]Total U.S. Auto and Light Truck Sales (includes imports), BEA; [15]Net Exports of Goods and Services, 2005$, NIPA, BEA.

Previous Consensus Forecasts

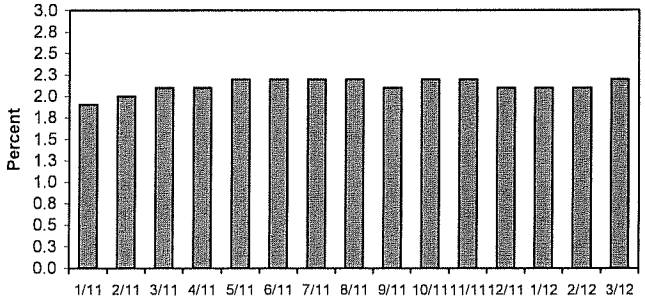
Consensus Forecasts For 2012	Real GDP Chained ('2005$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2005$)	Personal Cons. Exp. ('2005$)	Non-Res. Fix. Inv. ('2005$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2005$)
January 2011 Consensus	3.2	1.6	4.9	1.9	4.1	2.5	2.9	8.6	7.2	1.2	4.2	8.7	0.89	13.8	-491.2
February 2011 Consensus	3.3	1.7	4.9	2.0	4.1	2.4	2.9	8.1	6.2	1.2	4.3	8.6	0.89	13.9	-442.2
March 2011 Consensus	3.3	1.7	5.0	2.1	4.1	2.5	2.9	8.2	6.4	1.1	4.3	8.4	0.86	14.0	-431.8
April 2011 Consensus	3.2	1.7	5.0	2.1	4.1	2.5	2.9	8.0	6.6	1.2	4.3	8.2	0.83	14.1	-415.2
May 2011 Consensus	3.2	1.8	5.0	2.2	4.2	2.4	2.8	8.1	6.5	1.1	4.3	8.2	0.82	14.1	-404.0
June 2011 Consensus	3.1	1.8	5.0	2.2	4.1	2.3	2.8	8.2	6.0	1.1	4.2	8.2	0.79	14.1	-404.2
July 2011 Consensus	3.0	1.8	4.9	2.2	4.0	2.2	2.6	7.8	5.9	0.9	4.0	8.3	0.76	14.0	-375.3
August 2011 Consensus	2.5	1.9	4.3	2.2	3.3	2.0	2.2	6.8	5.3	0.5	3.5	8.7	0.73	13.6	-397.0
September 2011 Consensus	2.2	1.8	4.0	2.1	3.0	1.9	2.1	6.2	4.8	0.2	2.9	8.9	0.71	13.4	-404.3
October 2011 Consensus	2.0	1.8	3.9	2.2	2.8	1.6	1.9	6.1	5.0	0.1	2.6	9.0	0.70	13.3	-401.6
November 2011 Consensus	2.1	1.9	4.1	2.2	2.9	1.4	2.0	7.1	5.4	0.1	2.5	9.0	0.69	13.5	-406.7
December 2011 Consensus	2.2	1.9	4.1	2.1	3.0	1.3	2.1	7.3	6.1	0.1	2.4	8.8	0.70	13.7	-410.4
January 2012 Consensus	2.2	1.9	4.1	2.1	3.1	1.4	2.1	7.2	6.6	0.1	2.3	8.7	0.71	13.7	-406.7
February 2012 Consensus	2.2	1.7	4.0	2.1	3.4	1.3	2.1	7.1	5.8	0.1	2.2	8.3	0.72	14.0	-408.2
March 2012 Consensus	**2.3**	**1.8**	**4.1**	**2.2**	**3.6**	**1.5**	**2.0**	**7.3**	**5.8**	**0.1**	**2.2**	**8.2**	**0.73**	**14.3**	**-408.6**
Difference From Jan. 2011 Forecast	-0.9	0.2	-0.8	0.3	-0.5	-1.0	-0.9	-1.3	-1.4	-1.1	-2.0	-0.5	-0.16	0.5	82.6
Forecast High	3.3	1.9	5.0	2.2	4.2	2.5	2.9	8.6	7.2	1.2	4.3	9.0	0.89	14.3	-375.3
Forecast Low	2.0	1.6	3.9	1.9	2.8	1.3	1.9	6.1	4.8	0.1	2.2	8.2	0.69	13.3	-491.2

Consensus Forecasts For 2013	Real GDP Chained ('2005$)	GDP Price Index	Nominal GDP (Cur. $)	Consumer Price Index	Indust. Prod. (Total)	Dis. Pers. Income ('2005$)	Personal Cons. Exp. ('2005$)	Non-Res. Fix. Inv. ('2005$)	Corp. Profits (Cur. $)	Treas. Bills 3-mo.	Treas. Notes 10-Year	Unempl. Rate (Civ.)	Housing Starts (Mil.)	Auto/Truck Sales (Mil.)	Net Exports ('2005$)
January 2012 Consensus	2.6	1.9	4.5	2.1	3.3	2.0	2.3	6.6	6.3	0.4	3.0	8.3	0.87	14.4	-401.7
February 2012 Consensus	2.6	1.9	4.6	2.1	3.2	2.1	2.3	6.7	5.9	0.2	2.9	7.9	0.88	14.6	-400.6
March 2012 Consensus	**2.6**	**1.9**	**4.6**	**2.2**	**3.3**	**2.0**	**2.3**	**6.9**	**5.5**	**0.2**	**2.8**	**7.8**	**0.89**	**14.8**	**-407.4**
Difference From Jan. 2012 Forecast	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.3	-0.8	-0.2	-0.2	-0.5	0.02	0.4	-5.7
Forecast High	2.6	1.9	4.6	2.2	3.3	2.0	2.3	6.9	5.5	0.2	2.8	7.8	0.89	14.8	-407.4
Forecast Low	2.6	1.9	4.6	2.2	3.3	2.0	2.3	6.9	5.5	0.2	2.8	7.8	0.89	14.8	-407.4

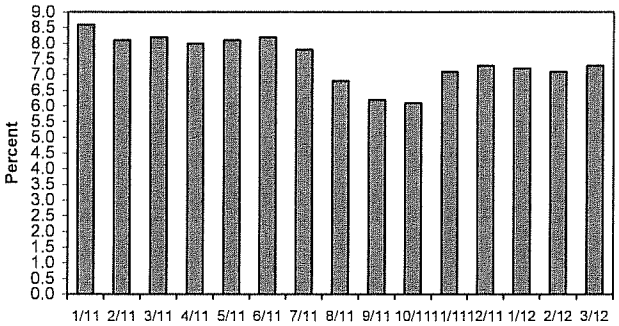
Consensus Forecasts Of Y/Y % Change In Real GDP In 2012



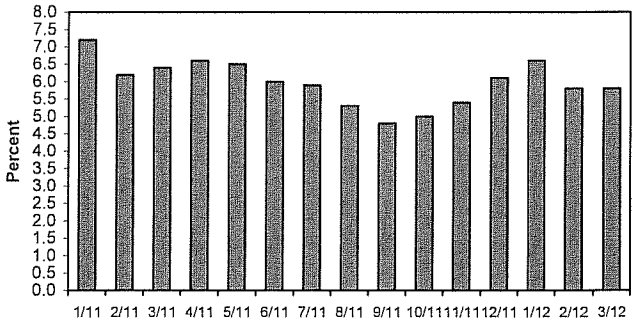
Consensus Forecasts Of Y/Y % Change In Consumer Price Index In 2012



Consensus Forecasts Of Y/Y % Change In Real Nonresidential Fixed Investment In 2012



Consensus Forecasts Of Y/Y % Change In Corporate Profits In 2012



3. Blue Chip Consensus: Percent Change From Prior Quarter At Annual Rate And Averages For Quarter.*

Actuals[1]	% Change From Prior Quarter At Annual Rate							Average For Quarter				
	Real GDP	GDP Price Index	CPI	Producer Price Index	Total Industrial Production	Disposable Personal Income	Personal Consump. Expend.	Unemploy-ment Rate	3-Mo. Treas. Bills	10-Yr. Treas. Notes	Change in Business Inventories	Real Net Exports
2011 1Q	0.4	2.5	4.5	10.2	4.8	1.2	2.1	9.0	0.1	3.5	49.1	-424.4
2Q	1.3	2.5	4.4	6.0	0.7	-0.5	0.7	9.0	0.1	3.2	39.1	-416.4
3Q	1.8	2.6	3.1	4.2	6.2	0.7	1.7	9.1	0.0	2.4	-2.0	-402.8
4Q	3.0	0.9	1.3	2.2	3.9	1.4	2.1	8.7	0.0	2.1	54.3	-404.4
Blue Chip Forecasts	% Change From Prior Quarter At Annual Rate							Average For Quarter				
2012 1Q Consensus	**2.1**	**1.9**	**2.3**	**1.7**	**3.8**	**1.7**	**2.0**	**8.3**	**0.1**	**2.0**	**44.6**	**-405.2**
Top 10 Avg.	2.8	2.7	3.1	3.6	5.7	3.1	2.8	8.5	0.1	2.1	65.1	-390.5
Bot. 10 Avg.	1.5	1.0	1.7	-0.6	2.2	0.3	1.1	8.2	0.0	1.8	18.1	-423.1
2Q Consensus	**2.2**	**1.7**	**2.0**	**1.6**	**3.3**	**2.2**	**2.2**	**8.3**	**0.1**	**2.1**	**44.6**	**-408.1**
Top 10 Avg.	2.9	2.4	3.1	3.9	4.5	3.0	2.8	8.6	0.1	2.4	65.9	-385.5
Bot. 10 Avg.	1.4	0.7	0.8	-1.0	1.9	1.3	1.6	8.0	0.0	1.9	21.7	-437.0
3Q Consensus	**2.4**	**1.9**	**2.3**	**1.5**	**3.1**	**2.2**	**2.3**	**8.2**	**0.1**	**2.3**	**45.6**	**-410.2**
Top 10 Avg.	3.0	2.6	3.3	3.3	4.3	2.9	3.0	8.5	0.2	2.6	68.7	-380.7
Bot. 10 Avg.	1.7	1.1	1.4	-0.9	1.8	1.4	1.7	7.9	0.0	2.0	25.5	-446.0
4Q Consensus	**2.6**	**1.8**	**2.1**	**2.0**	**3.1**	**2.4**	**2.4**	**8.1**	**0.1**	**2.4**	**47.3**	**-410.2**
Top 10 Avg.	3.4	2.6	3.0	3.5	4.6	3.1	3.2	8.5	0.2	3.0	72.5	-372.4
Bot. 10 Avg.	1.8	1.0	1.2	0.2	1.8	1.6	1.7	7.7	0.0	2.0	26.3	-457.5
2013 1Q Consensus	**2.5**	**2.1**	**2.1**	**2.3**	**3.1**	**0.9**	**2.1**	**8.0**	**0.1**	**2.6**	**48.1**	**-408.3**
Top 10 Avg.	3.3	2.9	3.0	4.2	4.4	2.9	3.0	8.4	0.3	3.2	71.6	-361.6
Bot. 10 Avg.	1.6	1.3	1.4	0.5	1.4	-2.7	0.9	7.5	0.0	2.1	27.9	-470.7
2Q Consensus	**2.7**	**1.9**	**2.1**	**1.9**	**3.3**	**2.4**	**2.3**	**7.8**	**0.2**	**2.7**	**49.1**	**-406.8**
Top 10 Avg.	3.5	2.6	3.0	3.7	4.6	3.5	3.2	8.3	0.4	3.5	71.6	-348.8
Bot. 10 Avg.	2.0	1.1	1.2	-0.1	1.9	1.3	1.5	7.4	0.0	2.1	28.5	-481.0
3Q Consensus	**2.9**	**2.0**	**2.3**	**1.9**	**3.4**	**2.4**	**2.4**	**7.7**	**0.3**	**2.9**	**48.7**	**-407.6**
Top 10 Avg.	3.6	2.7	3.4	3.8	4.9	3.3	3.2	8.3	0.7	3.7	70.3	-341.5
Bot. 10 Avg.	2.2	1.2	1.5	-0.2	1.9	1.3	1.7	7.1	0.0	2.2	28.9	-488.9
4Q Consensus	**3.0**	**2.1**	**2.2**	**2.2**	**3.4**	**2.7**	**2.6**	**7.6**	**0.4**	**3.0**	**49.1**	**-405.4**
Top 10 Avg.	4.0	2.8	3.2	3.8	4.8	3.9	3.6	8.2	1.1	3.9	69.9	-324.5
Bot. 10 Avg.	2.1	1.3	1.5	0.7	1.9	1.5	1.6	7.0	0.1	2.3	29.3	-498.4

4. Blue Chip Consensus: Quarterly Annualized Values And Percent Change From Same Quarter In Prior Year.*

Real Gross Domestic Product

	Billions Of Chained 2005$ (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2011	2012	2013	2011	2012	2013
1Q	13227.9	**13500.6**	**13827.5**	2.2	**2.1**	**2.4**
2Q	13271.8	**13574.3**	**13920.3**	1.6	**2.3**	**2.5**
3Q	13331.6	**13655.1**	**14018.6**	1.5	**2.4**	**2.7**
4Q	13429.9	**13743.4**	**14123.3**	1.6	**2.3**	**2.8**

GDP Chained Price Index

	Index 2005 = 100 (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2011	2012	2013	2011	2012	2013
1Q	112.4	**114.6**	**116.7**	1.8	**2.0**	**1.9**
2Q	113.1	**115.1**	**117.3**	2.1	**1.7**	**1.9**
3Q	113.8	**115.6**	**117.8**	2.4	**1.6**	**1.9**
4Q	114.1	**116.1**	**118.5**	2.1	**1.8**	**2.0**

Total Industrial Production

	Index 2002 = 100 (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2011	2012	2013	2011	2012	2013
1Q	92.8	**96.2**	**99.2**	5.5	**3.7**	**3.1**
2Q	92.9	**97.0**	**100.0**	3.8	**4.4**	**3.2**
3Q	94.4	**97.7**	**100.9**	3.7	**3.5**	**3.2**
4Q	95.3	**98.5**	**101.7**	3.9	**3.3**	**3.3**

Consumer Price Index

	Index 1982-1984 = 100 (SAAR)			% Change From Same Quarter In Prior Year[2]		
	Actual	Forecast[1]		Actual	Forecast	
Quarter	2011	2012	2013	2011	2012	2013
1Q	222.1	**228.3**	**233.1**	2.1	**2.8**	**2.1**
2Q	224.5	**229.4**	**234.3**	3.3	**2.2**	**2.1**
3Q	226.2	**230.7**	**235.7**	3.8	**2.0**	**2.2**
4Q	227.0	**231.9**	**237.0**	3.3	**2.2**	**2.2**

***See explanatory notes on inside of back cover for details of how this data is compiled.**

BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
CANADA	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**2.1**	**2.4**	**2.0**	**2.1**	**-40.3**	**-36.8**	**1.01**	**1.02**	**1.13**	**1.54**
Top 3 Avg.	2.3	2.9	2.4	2.4	-31.3	-24.5	1.04	1.08	1.52	2.12
Bottom 3 Avg.	1.8	2.0	1.8	1.9	-46.6	-45.4	0.97	0.97	0.84	0.99
Last Month Avg.	2.0	2.5	2.0	2.1	-44.0	-39.9	1.02	1.02	1.13	1.57
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	3.2	2.5	1.8	2.9	-41.8	-47.1	0.98	0.97	0.94	0.95
MEXICO	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**3.3**	**3.7**	**4.0**	**3.7**	**-14.4**	**-18.5**	**12.92**	**12.94**	**4.37**	**4.96**
Top 3 Avg.	4.0	4.4	4.9	4.5	-9.3	-9.9	13.77	14.23	4.67	5.41
Bottom 3 Avg.	2.9	3.2	3.4	3.3	-21.6	-26.8	12.43	12.17	4.10	4.56
Last Month Avg.	3.3	3.8	3.8	3.8	-17.0	-20.4	12.97	12.94	4.39	4.92
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	5.4	3.9	4.2	3.8	-9.9	-11.6	12.80	12.10	4.27	4.22
JAPAN	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**1.6**	**1.7**	**-0.3**	**0.0**	**95.7**	**85.1**	**79.5**	**83.7**	**0.19**	**0.32**
Top 3 Avg.	2.4	2.4	0.2	0.6	133.5	131.0	83.9	89.9	0.31	0.75
Bottom 3 Avg.	1.1	1.0	-0.7	-0.5	54.5	20.1	73.7	78.1	0.07	0.07
Last Month Avg.	1.8	1.8	-0.3	0.0	113.6	98.0	79.2	83.0	0.19	0.30
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	4.4	-0.9	-1.0	-0.3	194.8	130.3	80.9	81.7	0.15	0.16
UNITED KINGDOM	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**0.5**	**1.7**	**2.6**	**2.2**	**-42.9**	**-38.3**	**1.55**	**1.57**	**0.86**	**1.11**
Top 3 Avg.	0.9	2.2	2.9	2.9	-17.5	-0.5	1.61	1.66	1.14	1.63
Bottom 3 Avg.	-0.1	1.1	2.3	1.8	-71.9	-77.4	1.48	1.47	0.55	0.70
Last Month Avg.	0.4	1.8	2.6	2.2	-37.0	-33.4	1.57	1.60	0.90	1.21
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	1.8	0.8	3.3	4.5	-43.9	-38.2	1.59	0.61	1.10	0.80
SOUTH KOREA	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**3.1**	**4.1**	**3.0**	**3.0**	**25.2**	**22.8**	**1088**	**1044**	**3.43**	**3.79**
Top 3 Avg.	3.7	4.6	3.3	3.4	40.0	33.8	1122	1110	3.84	4.33
Bottom 3 Avg.	2.5	3.5	2.5	2.6	15.4	12.9	1052	989	3.06	3.35
Last Month Avg.	3.2	4.0	3.0	2.9	16.6	15.7	1083	1042	3.45	3.83
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	6.2	3.6	3.0	4.0	35.0	23.2	1119	1128	3.52	3.15
GERMANY	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**0.5**	**1.6**	**1.8**	**1.7**	**146.3**	**140.8**	**1.27**	**1.27**	**0.81**	**1.02**
Top 3 Avg.	0.9	2.3	2.2	2.1	170.6	169.9	1.35	1.37	1.03	1.50
Bottom 3 Avg.	-0.1	0.9	1.6	1.3	116.9	104.9	1.17	1.17	0.60	0.67
Last Month Avg.	0.4	1.5	1.8	1.8	139.2	135.5	1.29	1.29	0.94	1.23
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	3.6	3.1	1.2	2.5	173.2	176.1	1.33	1.39	0.98	1.10
TAIWAN	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**3.2**	**4.7**	**1.4**	**1.8**	**37.1**	**37.7**	**29.75**	**29.09**	**1.08**	**1.42**
Top 3 Avg.	4.2	5.5	1.8	2.1	40.8	41.9	31.16	30.50	1.59	1.89
Bottom 3 Avg.	2.1	3.9	0.9	1.5	32.4	32.4	29.11	28.14	0.71	1.07
Last Month Avg.	3.3	4.5	1.4	1.8	36.6	37.3	29.67	29.23	1.10	1.43
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	2.7	4.0	2.8	1.4	34.8	37.8	29.40	29.50	1.15	1.18
NETHERLANDS	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**-0.4**	**1.3**	**2.1**	**1.9**	**54.6**	**55.5**	**1.27**	**1.27**	**0.81**	**1.02**
Top 3 Avg.	0.3	1.8	2.5	2.6	60.9	60.1	1.35	1.37	1.03	1.50
Bottom 3 Avg.	-0.9	0.7	1.7	1.4	49.4	48.9	1.17	1.17	0.60	0.67
Last Month Avg.	-0.1	1.3	2.0	2.0	53.4	55.8	1.29	1.29	0.94	1.23
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	1.6	1.3	0.9	2.5	42.3	58.3	1.33	1.39	0.98	1.11

*Best estimates available. **In most cases, actual data for 2011 GDP, consumer prices and current account are not yet available. Where we don't have actual data yet, figures are consensus forecasts from December 10, 2011 issue of *Blue Chip Economic Indicators*. [1]Figures are currency units per U.S. dollar except for U.K., Australia and the Euro.

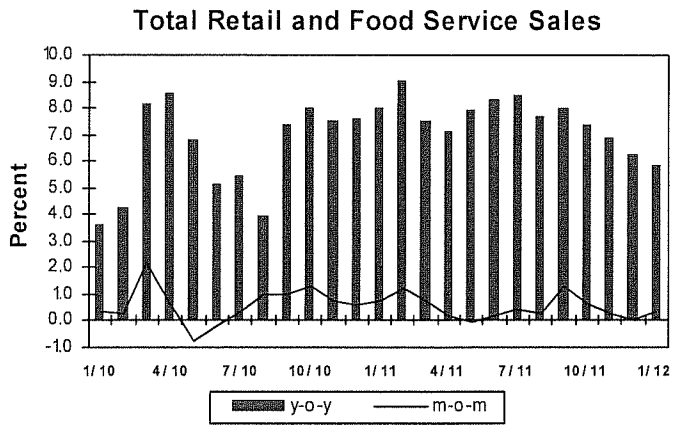
BLUE CHIP INTERNATIONAL CONSENSUS FORECASTS

	ANNUAL DATA						END OF YEAR			
	Real Economic Growth % Change GDP		Inflation % Change Consumer Prices		Current Account In Billions Of U.S. Dollars		Exchange Rate [1] Against U.S. $		Interest Rates 3-Month	
RUSSIA	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**3.6**	**3.9**	**5.8**	**6.1**	**74.3**	**53.9**	**30.9**	**31.1**	**6.91**	**6.84**
Top 3 Avg.	4.4	4.6	7.5	7.3	89.4	75.1	33.9	34.1	8.46	8.30
Bottom 3 Avg.	3.1	3.3	4.8	5.3	59.6	24.3	29.6	29.7	5.33	5.37
Last Month Avg.	3.5	3.9	6.2	6.0	75.1	59.3	30.4	30.3	6.79	6.70
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	4.3	4.3	6.9	8.6	60.9	82.7	29.20	28.40	6.61	8.00
FRANCE	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**-0.1**	**1.0**	**2.0**	**1.8**	**-45.8**	**-38.2**	**1.27**	**1.27**	**0.81**	**1.02**
Top 3 Avg.	0.4	1.6	2.4	2.0	-37.9	-17.9	1.35	1.37	1.03	1.50
Bottom 3 Avg.	-0.7	0.3	1.5	1.4	-53.1	-57.3	1.17	1.17	0.60	0.67
Last Month Avg.	-0.2	1.1	1.9	1.8	-58.6	-50.1	1.29	1.29	0.94	1.23
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	1.4	1.7	1.7	2.3	-51.2	-61.8	1.33	1.39	0.98	1.10
BRAZIL	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**3.2**	**4.4**	**5.3**	**5.1**	**-55.9**	**-61.3**	**1.78**	**1.78**	**9.70**	**9.55**
Top 3 Avg.	3.8	5.5	5.7	5.9	-42.5	-46.2	1.88	1.95	10.03	10.00
Bottom 3 Avg.	2.4	3.5	4.9	4.2	-71.3	-77.4	1.69	1.64	9.36	9.08
Last Month Avg.	3.2	4.4	5.3	5.0	-54.7	-59.8	1.79	1.79	9.76	9.68
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	7.5	2.8	5.0	6.5	-49.6	-47.8	1.72	1.66	10.40	11.17
HONG KONG	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**3.2**	**4.4**	**4.2**	**3.6**	**12.5**	**14.6**	**7.77**	**7.77**	**0.37**	**0.63**
Top 3 Avg.	4.4	5.1	4.9	4.5	21.6	26.1	7.80	7.80	0.50	1.12
Bottom 3 Avg.	2.1	3.8	3.6	2.9	5.3	5.8	7.74	7.73	0.23	0.33
Last Month Avg.	3.4	4.5	4.1	3.6	13.3	16.5	7.78	7.77	0.33	0.69
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	7.3	5.0	3.9	5.3	16.1	12.5	7.76	7.79	0.40	0.20
INDIA	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**7.0**	**7.9**	**6.9**	**6.7**	**-58.7**	**-64.2**	**49.0**	**47.1**	**8.53**	**8.43**
Top 3 Avg.	7.5	8.6	7.9	7.9	-48.2	-47.1	51.1	50.0	9.89	9.73
Bottom 3 Avg.	6.4	7.4	6.3	5.7	-69.3	-80.2	46.6	44.4	7.60	7.33
Last Month Avg.	7.1	8.0	6.9	6.8	-58.4	-60.7	49.2	47.4	8.34	8.17
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	8.5	7.0	1.0	8.8	-39.8	-56.2	49.0	44.9	9.06	7.14
CHINA	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**8.2**	**8.5**	**3.5**	**3.7**	**236.0**	**236.7**	**6.12**	**5.91**	**4.89**	**4.86**
Top 3 Avg.	8.6	9.0	4.2	4.7	314.5	337.3	6.24	6.09	6.13	6.17
Bottom 3 Avg.	7.7	8.0	3.1	2.5	136.9	119.8	5.99	5.69	3.65	3.37
Last Month Avg.	8.2	8.5	3.5	3.7	256.6	252.7	6.13	5.93	4.92	4.91
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	10.4	9.2	3.3	5.4	279.1	280.4	6.29	6.57	5.28	4.68
AUSTRALIA	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**3.2**	**3.2**	**2.6**	**2.9**	**-48.2**	**-57.6**	**1.02**	**1.00**	**4.18**	**4.52**
Top 3 Avg.	3.8	3.9	3.1	3.2	-32.8	-37.7	1.07	1.07	4.33	4.78
Bottom 3 Avg.	2.8	2.6	2.1	2.5	-68.3	-84.8	0.97	0.95	3.94	4.28
Last Month Avg.	3.3	3.2	2.7	3.0	-38.2	-46.5	1.02	1.02	4.26	4.65
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	2.7	1.9	2.8	3.4	-40.0	-32.0	0.93	0.98	4.69	4.95
EUROZONE	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
March Consensus	**-0.4**	**0.9**	**2.0**	**1.7**	**0.5**	**10.1**	**1.27**	**1.27**	**0.81**	**1.02**
Top 3 Avg.	0.2	1.6	2.4	1.9	51.2	73.7	1.35	1.37	1.03	1.50
Bottom 3 Avg.	-1.1	-0.1	1.7	1.4	-45.3	-48.0	1.17	1.17	0.60	0.67
Last Month Avg.	-0.4	1.0	1.9	1.8	-21.5	-13.5	1.29	1.29	0.94	1.23
	2010*	2011**	2010*	2011**	2010*	2011**	Latest	Year Ago	Latest	Year Ago
Actual	1.9	1.5	2.0	2.7	-77.0	-50.6	1.33	1.39	0.98	1.10

Contributors to Blue Chip International Survey: IHS Global Insight, US; Federal Express Corporation, USA; Credit Suisse, US; JP Morgan, US; Economist Intelligence Unit, UK; BMO Capital Markets, Canada; UBS, US; AIG, New York, NY; Oxford Economics, US; Citigroup U.S. Economics; Societe Generale, New York, NY; Bank of America-Merrill Lynch, US; Nomura Capital Markets America, US; WestLB; Germany; Morgan Stanley; US; Moody's Capital Markets, US; Wells Fargo & Company, US; Moody's Analytics, US; Swisse Re, U.S.; Barclays Capital, US; General Motors Corp., US; Wintrust Wealth Management, US; and Grupo de Economistas y Asociados, Mexico.

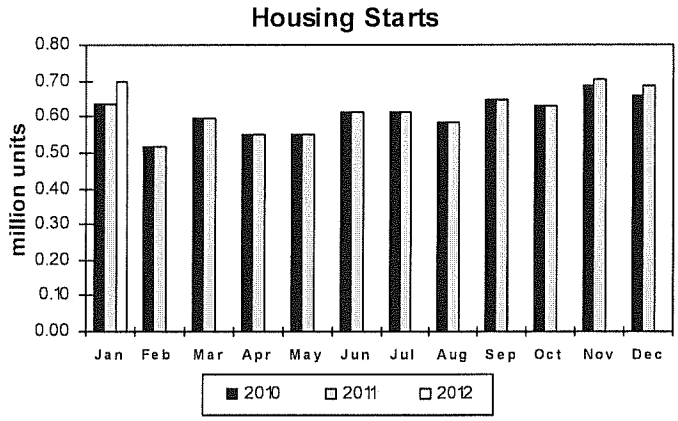
Recent Developments:

Retail Sales Increased Less Than Expected In January



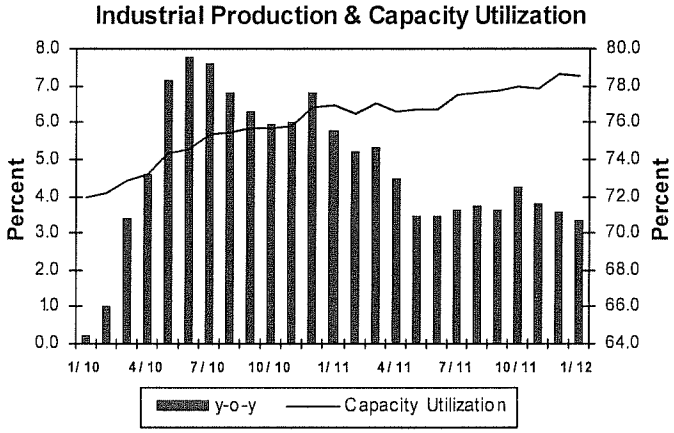
Retail sales increased a smaller-than-expected 0.4% in January and sales gains in the prior two months were revised down a bit. The y/y percent change in retail sales dropped to 5.8%, the fourth consecutive month of sequential slowing. Sales at auto dealers fell a surprisingly large -1.2%, the drop likely explained by very generous sales incentives given that unit sales of auto and light trucks rose 4.7% during January. Retail sales excluding autos, gasoline and building material stores increased a healthier looking 0.7% during the month. However, some of that strength may have resulted from unseasonably mild weather. Food store sales increased an unusually large 1.3%. Elsewhere, sales at building material stores rose 0.2% following the 2.0% surge in December while sales at sporting goods stores jumped 1.1%, the first increase since September. Most analysts anticipate a sizable rise of 0.9%-1.0% in February retail sales given the 5.6% gain in unit sales of auto and light trucks. However, fleet rather than consumer purchases of autos may have again accounted for some of the strength. Sales at gas stations likely rose sharply on surging prices. A much smaller gain is expected in retail sales minus autos, gasoline and building materials.

Housing Starts Increased In January On the Back Of Continued Multi-Family Strength



Total housing starts increased 1.5% in January to an annualized rate of 699,000. Starts of single-family homes fell 1.0% while starts of multi-family homes remained strong, rising 8.5%. Total permits increased 0.7% in January with permits for both single-family and multi-family homes registering increases of less than a percentage point. Housing completions in January fell to another all-time. New home sales fell 0.9% in January to an annual rate of 321,000 but upward revisions to prior months left sales during the month at a higher level than had been expected. The inventory of new homes for sale declined to a fresh record annualized low of 151,000 units. The median price of a single-family home for sale rose slightly in January but was down 9.6% on a y/y basis. Sales of existing homes increased 4.3% in January with sales of single-family homes up 3.9%. Distressed properties accounted for 35% of sales. The median price for existing homes fell 4.6% in January and was down 2.0% on a y/y basis. Contract cancellations were still running at a high rate of 33% in January versus just 9% a year earlier.

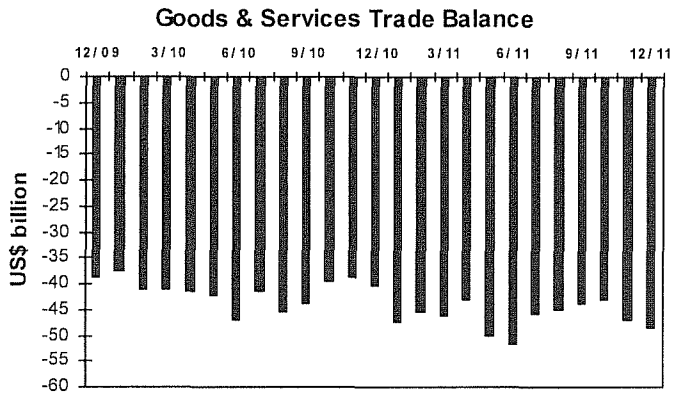
Industrial Production Unchanged In January As Utility And Mining Output Fall



Total industrial production was unchanged in January versus expectations of an increase of 0.4% or so. However, the December's increase was revised up 0.6 of a percentage point to 1.0% and November's was revised from a -0.3% contraction to unchanged. Additionally, all of January's softness was concentrated in utilities and mining that respectively contracted -2.5% and -1.8% on the month. Utility output has been hurt this winter by unusually warm temperatures while mining output likely suffered in January from cutbacks in natural gas production due to excess demand and weak prices. Manufacturing output, in contrast, increased a solid 0.8% after an upwardly revised 1.5% gain in December, supported by a second straight month of strong auto and parts production. The Institute of Supply Management's index of manufacturing activity declined to 52.4 in February from 54.1. The new orders index fell back to 54.9 and the production index slipped to 55.3, but both remained above their six-month averages. The export index, however, jumped to 59.5, indicating some strengthening of export demand. Of some concern, the prices index rose to its highest level since June 2011, a development likely signaling some squeeze on profits.

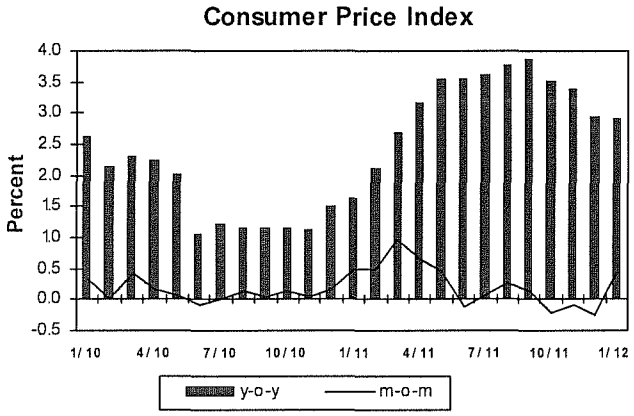
Recent Developments:

Trade Deficit Widened For A Second Straight Month In December



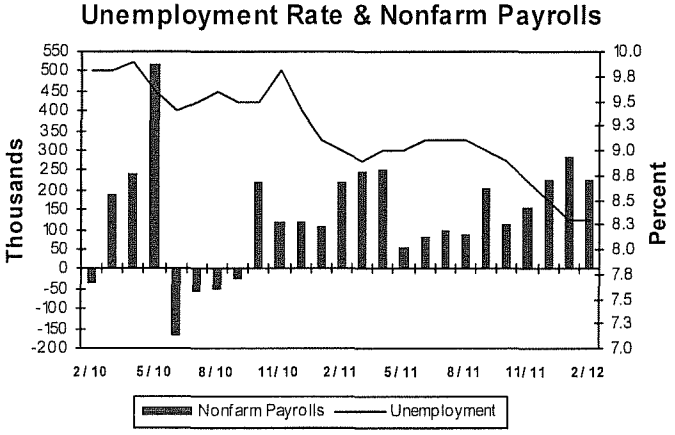
The goods and services deficit widened for a second consecutive month in December and the trade gap for all of 2011 was the largest since 2008. The December deficit was -$48.8 billion, 3.6% larger than November -$47.1 billion. Total exports increased 0.7% in the final month of last year while imports rose 1.3%. Total goods exports increased but exports of non-automotive capital goods and consumer goods dropped, the latter led by a sharp decline in pharmaceuticals. The increase in December imports was led by capitals goods, including industrial machines, semiconductors, and civilian aircraft. Imports of consumer goods also increased, driven by pharmaceuticals and other household goods. Despite an increase in average petroleum import prices in December to $104.13 per barrel (up 30.5% y/y), the combination of a decline in petroleum imports and a strong increase in petroleum exports resulted in a narrowing in the petroleum trade deficit to -$26.9 billion from -$27.6 billion in November. The ISM's export index suggests overseas demand remains healthy, however, sharp recent increases in oil prices will likely produce an even wider trade deficit in January.

Y/Y Change In Core Consumer Price Index Rises To Highest Level Since September 2008



The Consumer Price Index (CPI) and the CPI excluding food and energy prices (core CPI) both increased 0.2% in January. The y/y change in the overall CPI dropped slightly to 2.9%, the fourth consecutive decline, while the y/y change in the core CPI rose to 2.3%, the highest level since September 2008. January generally saw broad-based increases in prices with the exception of housing fuels and utilities where the fourth warmest January temperatures on record in the continental U.S. produced a decline in demand for home heating. Both energy and food prices increased 0.2% in January. The gain in energy prices was the first since September and was led by higher gasoline costs. The January increase in the core CPI was led by increases for apparel (related to warm weather), rents (upward pressure from low vacancy rates), transportation (higher gasoline prices), and medical care (rising prices for prescription drugs). The February CPI is likely to jump 0.4%-0.5%, led by surging gasoline prices since the start of this year. The February core CPI will likely be up another 0.2%. But more favorable comparisons would leave the y/y rate of change unchanged at 2.3%.

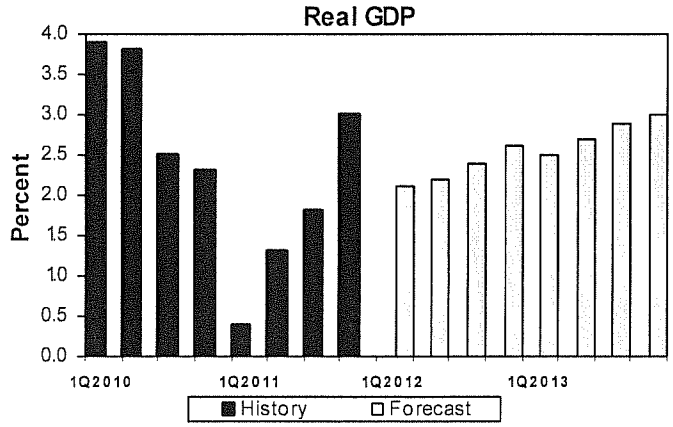
February Gains Lifted Job Growth Over Last Six Months To Fastest Pace Since 2006



Total nonfarm payrolls increased a better-than-expected 227,000 in February and upward revisions added 61,000 to payroll growth in December and January. The gains lifted job growth over the past six months to its fastest pace since 2006. Private sector payrolls increased 233,000 last month. Employment gains were relatively widespread in February. Goods producing firms added 24,000 jobs in February with manufacturing payrolls up by 31,000. Service sector employment increased by 209,000 during the month. Temporary employment, often a harbinger of overall growth in payrolls, was up 45,000. However, construction payrolls fell by 13,000, retailers' payrolls dropped 7,000 and government payrolls fell a further 6,000. Household employment climbed by 428,000 and the civilian labor force increased 476,000. The unemployment rate remained at 8.3% for a second straight month. Average hourly earnings inched up by 0.1% in February, matching the downwardly revised increase in January. The average workweek stayed at 34.5 for a third consecutive month but the manufacturing workweek increased for a third straight month to 41.0 hours in February.

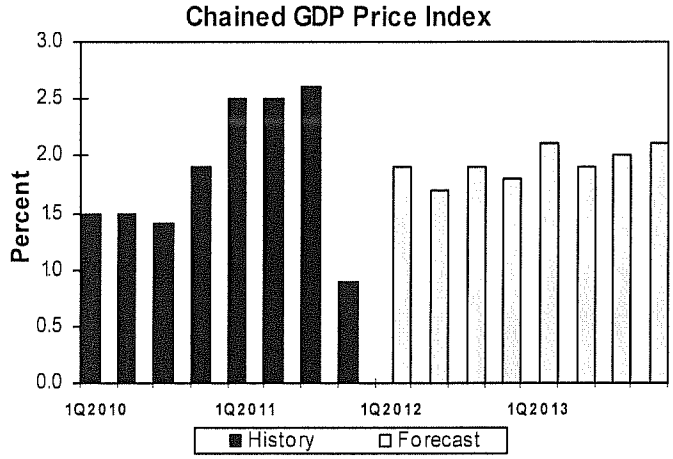
Quarterly U.S. Forecasts:

Real GDP



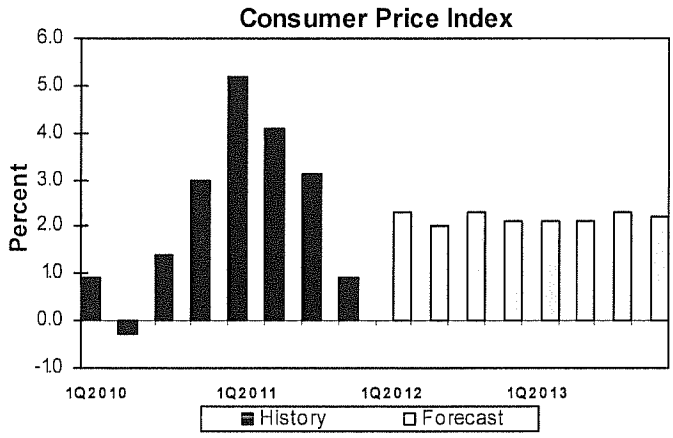
Real GDP grew an upwardly revised 3.0% (saar) in Q4 2011, according to the government's second estimate, 0.2 of a point better than originally estimated. Upward revisions to the major components of GDP were broad-based. Consumer spending was revised upwardly on better durable goods and services spending. Investment in both residential and nonresidential structures was higher than originally thought. The net export deficit was smaller than first estimated and government spending declined less than previously estimated. Inventory accumulation still accounted for almost two-thirds of the gain in GDP but final sales was revised up to an increase of 1.1% compared with the originally reported 0.8%. The consensus still looks for real GDP to grow 2.1% in the current quarter, 2.2% in Q2, 2.4% in Q3 and 2.6% in Q4. While the consensus forecast of y/y growth in real GDP this year increased to 2.3% the estimate of q4/q4 growth was unchanged at 2.3%. The consensus estimates of y/y and q4/q4 real GDP growth in 2013 were unchanged this month at 2.6% and 2.8%, respectively.

GDP Chain Price Index



The GDP chained price index increased an upwardly revised 0.9% in Q4 2011, 0.5 of a percentage point faster than originally estimated by the government. That still marked the slowest rate of increase since Q3 2009. For 2011 as a whole, the GDP price index still is estimated to have increased 2.1% y/y versus 1.2% in 2010 and 1.1% in 2009. The slowdown in Q4 primarily reflected a reversal of the early-year run-up in commodity prices, especially for energy. However, new auto prices also softened, unwinding some of the jump in prices that occurred when supply-chain disruptions caused by Japan's earthquake produced shortages of some models. The personal consumption expenditures price index increased an upwardly revised 1.2%, also 0.5 of a point more than originally estimated. Elsewhere, the deflator for nonresidential fixed investment increased an unrevised 1.6% while the deflator for residential investment fell an upwardly revised -0.2%, the first decline since Q2 2010. The consensus now sees the GDP price index increasing 1.8% y/y in 2012, 0.1 of a point more than last month. An increase of 1.9% still is seen in 2013. It is expected to register q4/q4 increases of 1.8% and 2.0%, respectively, this year and next.

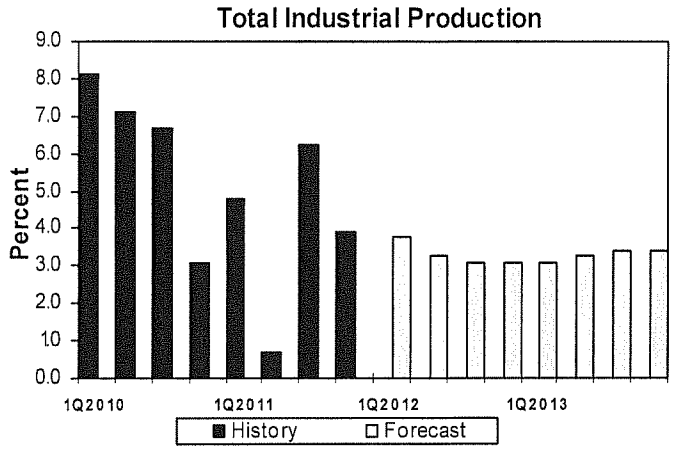
Consumer Price Index



The Consumer Price Index (CPI) increased at a upwardly revised but still slower-than-anticipated rate of 1.3% (saar) in Q4 2011 versus 3.1% in Q3. The slowdown was driven by declines in energy prices during each and every month of the quarter, falling prices for new vehicles, and slower food price inflation For all of last year, the CPI increased 3.2% on a y/y basis and 3.0% measured December-over-December. As of January, the 12-month change in the CPI stood at 2.9% versus 3.9% last September. The CPI excluding food and energy prices (core CPI) increased an upwardly revised 1.9% in Q4 versus 2.5% in Q3 and was 2.3% higher on a 12-month basis in January. The pace of increase in the overall CPI is predicted to accelerate in the current quarter, propelled especially by a rebound in gasoline prices. For all of 2012 the CPI now is predicted by the consensus to increase 2.2% on both a y/y basis and q4/q4 basis. The y/y estimate rose 0.1 of a point this month while the q4/q4 forecast increased 0.2 of a point. The consensus also predicts the CPI will register y/y and q4/q4 increases of 2.2% in 2013. The y/y estimate rose 0.1 of a point this month but the q4/q4 forecast was the same as last month. .

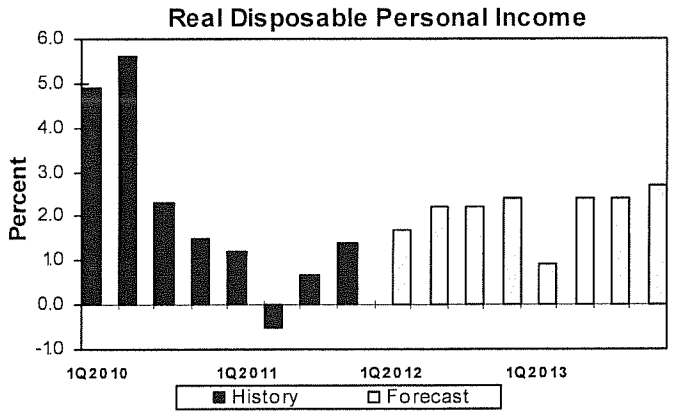
Quarterly U.S. Forecasts:

Industrial Production



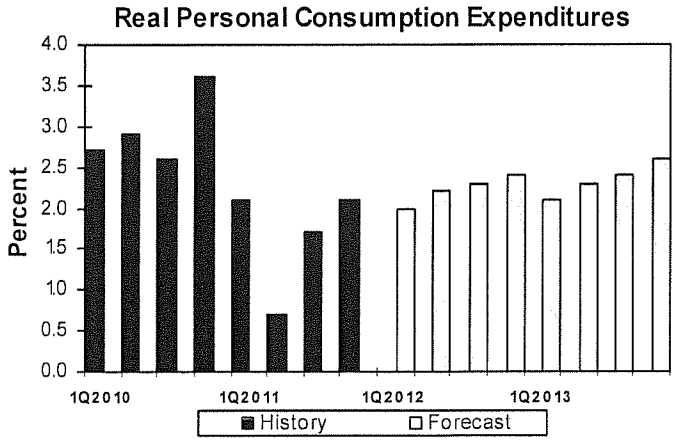
Total industrial production increased an upwardly revised of 3.9% (saar) in the final quarter of last year, 0.8 of a percentage point faster than originally estimated by the government. Manufacturing output grew even faster, increasing at an upwardly revised rate of 5.1% versus the original estimate of 3.9%. For the year, total industrial increased 4.2% versus 5.3% in 2010. Manufacturing output rose 4.5% in 2011 compared to 5.4% in 2010. While softness in utility output due to an unseasonably mild winter has held back overall gains in total production over the past couple of months, manufacturing output increased 1.5% in December and 0.7% in January. Recent ISM reports also suggest industrial production started the year with some momentum. Nonetheless, the large build in business inventories during Q4 should suggest at least some caution. A continued rise in gasoline prices that threatens consumer spending might also discourage order flow to factories. The consensus now looks for y/y and q4/q4 growth in total industrial production of 3.6% and 3.3%, respectively, in 2012. It is projected to increase 3.3% on both a y/y and q4/q4 basis in 2013.

Real Disposable Personal Income



Real disposable personal income (DPI) grew at upwardly revised rates of 0.7% (saar) in Q3 and 1.4% in Q4 of last year, according to the government's latest figures. Originally, real DPI was estimated to have contracted 1.9% in Q3 and grown just 0.8% in Q4. Nonetheless, real DPI still increased just 1.3% y/y in 2011 after growing 1.8% in 2010. In current dollars, DPI grew 3.8% in 2011 versus 3.6% in 2010. Wage and salary disbursements in current dollars increased 4.3% last year but interest income fell for a second consecutive year. Growth in current dollar DPI at least ended 2011 on a stronger note with an increase of 0.5% in December, the biggest increase since April 2011. Moreover, it increased a further 0.3% in January of this year. However, real DPI fell 0.1% in November, rose 0.3% in December but dropped another 0.1% in January. The consensus now looks for real DPI to record a y/y increase of 1.5% in 2012, 0.2 of a point better than predicted a month ago. The consensus estimate of 2013 growth in real DPI of 2.0% is highly dependent on what Congress does at the end of this year when the Bush-era tax cuts are scheduled to sunset.

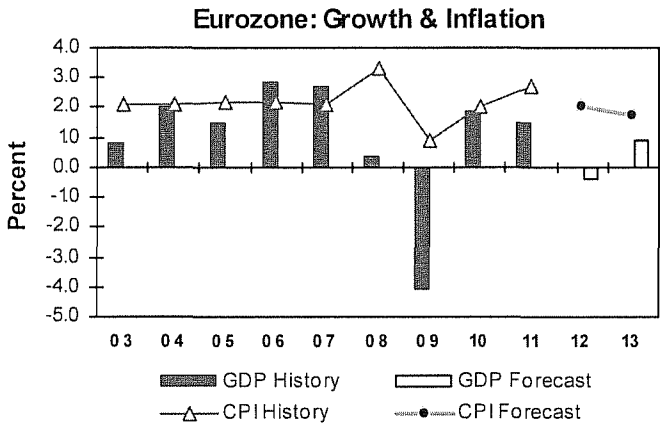
Real Personal Consumption Expenditures



Real personal consumption expenditures (PCE) grew a less than expected but upwardly revised 2.1% (saar) in Q4 2011, according to the government's latest estimate. Spending in Q4 on both durable and nondurable goods accelerated to the fastest pace since Q1 of last year. However, spending on consumer services expanded at an upwardly revised pace of just 0.7% as the cost of heating homes plummeted due to unseasonably mild winter temperatures. For all of last year, real PCE still is estimated to have grown 2.2%, slightly better than the 2.0% advance in 2010. Because consumer spending grew faster than DPI, the personal saving rate averaged 4.4% for all of 2011 and 4.5% in the final quarter of the year. That compares to an average of 5.3% in 2010 and 5.1% in 2009. Improving labor markets and lower inflation are expected to promote continued growth in real PCE this year but no boom. Indeed, real PCE was unchanged over the three months ending in January. Real PCE is projected by the consensus to register y/y growth of 2.0% this year and 2.3% in 2013. The 2012 estimate slipped 0.1 of a point this month but the 2013 forecast went unchanged.

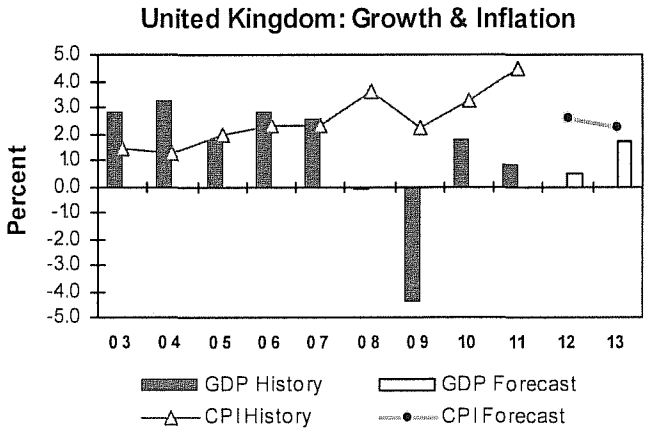
International Forecasts:

Eurozone



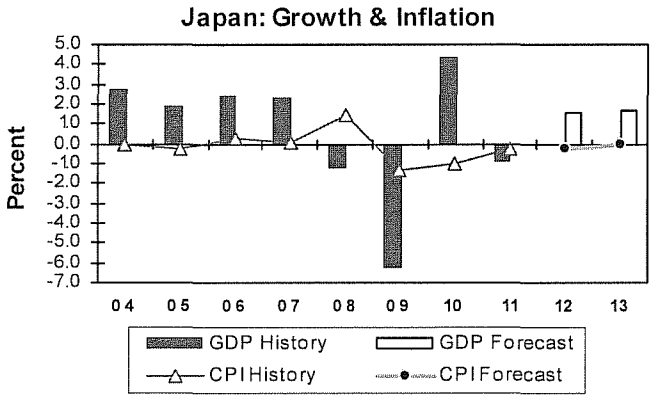
Real GDP in the Eurozone contracted -0.3% (q/q) in Q4 2011. France managed positive growth but GDP fell in Germany, Italy and Spain. A breakdown of GDP's components indicated broad-based weakness with declines in private consumption, government consumption, and investment. A narrowing of net exports prevented the GDP contraction from being even steeper. Moreover, brutal winter weather in February and record high oil prices (in euro terms) are likely to keep growth soft in the current quarter. Indeed, manufacturing and service sector PMI's for the Eurozone were back below the expansion/contraction level of 50 in February. While the European Central Bank's LTRO program has staved off a bank funding crisis and crippling credit crunch, credit conditions have nevertheless tightened considerably for households and companies. Implementation of additional austerity measures by some ember states also will continue to weigh on economic growth this year and next. The consensus now looks for real GDP in the Eurozone to contract -0.4% this year and to grow only 0.9% in 2013. The 2012 estimate is unchanged but 2013's fell 0.1 of point this month.

United Kingdom



Real GDP contracted 0.2% (q/q) in the final quarter of last year, according to the second estimate. Gross fixed capital formation fell by 2.8%, with business investment down 5.6%. Industrial output contracted by 1.4% while construction fell 0.5%. These declines offset a 0.5% rise in consumer spending, the first quarterly increase since Q2 2010, and a 2.3% increase in exports. Services output was unchanged. On the heels of news that the U.K. economy contracted last quarter, the Bank of England voted 7-2 on February 9th to boost its QE program by a further GBP 50 billion but stood pat at the early March meeting. Government officials and most private sector economists say a return to recession will be avoided with GDP growth returning to positive territory this quarter. However, unemployment is climbing, credit is tight and the economy is reeling from the deepest budget cuts in peacetime history. Rising oil prices also are a threat to continued growth. The consensus forecast of real GDP growth in 2012 increase 0.1 of a percentage point this month to 0.5% (y/y) but the estimate of growth in 2013 fell by an equal amount to 1.7%.

Japan



Japan's economy contracted an upwardly revised -0.7% (saar) in Q4 of last year, according to the government's second estimate. The decline had originally been estimated at -2.3%. The weakness in Q4 was largely attributable to slower global growth, a strengthening yen and floods in Thailand that weakened exports. Capital spending during Q4 is now estimated to have grown 4.6% in Q4, much better than the original estimate of 1.9%. Private consumption grew 0.4% in Q4, 0.1 of a point better than first though. Exports fell 0.6%. The decline in Q4 GDP followed 5.6% growth in Q3 as recovery from the March 2011 earthquake/tsunami got into full swing. Real GDP fell 1.8% in Q1 2011 and sank 2.1% in Q2. Japan posted a current-account deficit of $5.4 billion in January, the largest shortfall since comparable data began in 1985. The Bank of Japan expanded its QE program in February and changed the wording of its price target to make it more specific. The consensus now estimates real GDP will increase 1.6% this year and 1.7% in 2013, both estimates a bit lower than last month.

Databank:

2012

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.4											
Auto & Light Truck Sales (b)	14.13	15.04										
Personal Income (a, current $)	0.3											
Personal Consumption (a, current $)	0.2											
Consumer Credit (e)	8.6											
Consumer Sentiment (U. of Mich.)	75.0	75.3										
Household Employment (c)	847	428										
Non-farm Payroll Employment (c)	284	227										
Unemployment Rate (%)	8.3	8.3										
Average Hourly Earnings (cur. $)	23.28	23.31										
Average Workweek (All, hrs.)	34.5	34.5										
Industrial Production (d)	3.3											
Capacity Utilization (%)	78.5											
ISM Manufacturing Index (g)	54.1	52.4										
ISM Non-Manufacturing Index (g)	56.8	57.3										
Housing Starts (b)	0.699											
Housing Permits (b)	0.676											
New Home Sales (1-family, c)	321											
Construction Expenditures (a)	-0.1											
Consumer Price Index (nsa., d)	2.9											
CPI ex. Food and Energy (nsa., d)	2.3											
Producer Price Index (n.s.a., d)	4.1											
Durable Goods Orders (a)	-4.0											
Leading Economic Indicators (g)	0.4											
Balance of Trade & Services (f)	-52.6											
Federal Funds Rate (%)	0.08	0.10										
3-Mo. Treasury Bill Rate (%)	0.03	0.09										
10-Year Treasury Note Yield (%)	1.97	1.97										

2011

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.8	1.3	0.8	0.2	-0.1	0.2	0.4	0.3	1.3	0.7	0.3	0.0
Auto & Light Truck Sales (b)	12.64	13.24	13.02	13.13	11.68	11.51	12.20	12.09	13.05	13.22	13.60	13.50
Personal Income (a, current $)	1.1	0.5	0.5	0.4	0.3	0.1	0.1	-0.1	0.3	0.4	0.0	0.5
Personal Consumption (a, current $)	0.4	0.8	0.6	0.3	0.2	-0.2	0.8	0.1	0.7	0.2	0.1	0.0
Consumer Credit (e)	2.2	3.2	2.2	2.8	3.0	5.6	5.8	-4.7	3.7	3.3	9.8	7.9
Consumer Sentiment (U. of Mich.)	74.2	77.5	67.5	69.8	74.3	71.5	63.7	55.7	59.4	60.9	64.1	69.9
Household Employment (c)	110	221	213	-136	180	-423	65	304	353	190	317	176
Non-Farm Payroll Employment (c)	110	220	246	251	54	84	96	85	202	112	157	223
Unemployment Rate (%)	9.1	9.0	8.9	9.0	9.0	9.1	9.1	9.1	9.0	8.9	8.7	8.5
Average Hourly Earnings (cur. $)	22.86	22.88	22.92	22.97	23.02	23.05	23.13	23.12	23.16	23.12	23.23	23.25
Average Workweek (hrs.)	34.3	34.3	34.3	34.4	34.4	34.4	34.4	34.3	34.4	34.4	34.4	34.5
Industrial Production (d)	5.8	5.2	5.3	4.5	3.4	3.4	3.6	3.7	3.6	4.3	3.8	3.6
Capacity Utilization (%)	76.9	76.5	77.0	76.6	76.7	76.7	77.5	77.6	77.7	78.0	77.9	78.6
ISM Manufacturing Index (g)	59.9	59.8	59.7	59.7	54.2	55.8	51.4	52.5	52.5	51.8	52.6	53.1
ISM Non-Manufacturing Index (g)	58.3	59.0	56.3	54.4	54.5	53.3	53.4	53.8	52.6	52.6	52.6	53.0
Housing Starts (b)	0.636	0.518	0.593	0.549	0.553	0.615	0.615	0.585	0.646	0.628	0.685	0.657
Housing Permits (b)	0.568	0.534	0.574	0.563	0.609	0.617	0.601	0.625	0.589	0.628	0.702	0.689
New Home Sales (1-family, c)	310	281	305	316	308	303	295	290	302	311	318	324
Construction Expenditures (a)	-1.4	-1.0	-0.2	0.7	2.5	1.6	-3.3	2.2	1.1	0.3	1.9	1.4
Consumer Price Index (s.a., d)	1.6	2.1	2.7	3.2	3.6	3.6	3.6	3.8	3.9	3.5	3.4	3.0
CPI ex. Food and Energy (s.a., d)	1.0	1.1	1.2	1.3	1.5	1.6	1.7	2.0	2.0	2.1	2.2	2.2
Producer Price Index (n.s.a., d)	3.6	5.4	5.6	6.6	7.1	6.9	7.1	6.6	7.0	5.9	5.7	4.8
Durable Goods Orders (a)	4.0	-1.1	4.6	-2.5	2.0	-1.2	4.2	0.1	-1.4	0.1	4.2	3.2
Leading Economic Indicators (g)	0.2	0.9	0.7	-0.3	0.7	0.3	0.5	0.3	0.1	0.6	0.3	0.5
Balance of Trade & Services (f)	-47.5	-45.4	-46.1	-43.2	-50.2	-51.8	-45.6	-45.1	-44.0	-43.1	-47.5	-50.4
Federal Funds Rate (%)	0.17	0.16	0.14	0.10	0.09	0.09	0.07	0.10	0.08	0.07	0.08	0.07
3-Mo. Treasury Bill Rate (%)	0.15	0.13	0.10	0.06	0.04	0.04	0.04	0.02	0.01	0.02	0.01	0.01
10-Year Treasury Note Yield (%)	3.39	3.58	3.41	3.46	3.17	3.00	3.00	2.30	1.98	2.15	2.01	1.98

(a) month-over-month % change; (b) millions, saar; (c) thousands, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Long-Range Consensus U.S. Economic Projections

I. The table below shows the latest U.S. Blue Chip Consensus[1] projections by years for 2014through 2018 an average for the five-year period 2014-2018, and an average for the next five-year period 2019-2023. There are also Top 10 and Bottom 10 averages for each variable. Apply these projections cautiously. For the most part economic and political forces over such long time spans cannot be evaluated with accuracy.

ECONOMIC VARIABLE		YEAR 2014	2015	2016	2017	2018	Five-Year Averages 2014-18	2019-23
		Percent Change, Full Year-Over-Prior Year						
1. Real GDP (chained, 2005 dollars)	**CONSENSUS**	**3.0**	**3.0**	**2.9**	**2.8**	**2.7**	**2.9**	**2.5**
	Top 10 Avg.	3.7	3.6	3.4	3.1	3.0	3.4	2.8
	Bottom 10 Avg.	2.3	2.5	2.5	2.4	2.3	2.4	2.2
2. GDP Chained Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**
	Top 10 Avg.	2.7	2.8	2.7	2.8	2.8	2.8	2.7
	Bottom 10 Avg.	1.6	1.7	1.7	1.8	1.7	1.7	1.6
3. Nominal GDP (current dollars)	**CONSENSUS**	**5.1**	**5.2**	**5.1**	**5.0**	**4.9**	**5.1**	**4.7**
	Top 10 Avg.	6.1	6.0	6.0	5.9	5.7	5.9	5.4
	Bottom 10 Avg.	4.2	4.5	4.5	4.3	4.1	4.3	4.1
4. Consumer Price Index (for all urban consumers)	**CONSENSUS**	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**	**2.4**	**2.5**
	Top 10 Avg.	3.0	3.1	3.1	3.2	3.1	3.1	3.1
	Bottom 10 Avg.	1.9	1.9	1.9	1.9	1.9	1.9	1.9
5. Industrial Production (total)	**CONSENSUS**	**3.3**	**3.2**	**3.1**	**2.9**	**2.7**	**3.1**	**2.8**
	Top 10 Avg.	4.4	4.1	4.1	3.8	3.8	4.1	3.7
	Bottom 10 Avg.	2.1	2.3	2.1	2.0	1.7	2.1	2.0
6. Disposable Personal Income (chained, 2005 dollars)	**CONSENSUS**	**2.7**	**2.8**	**2.8**	**2.7**	**2.5**	**2.7**	**2.5**
	Top 10 Avg.	3.5	3.5	3.3	3.1	3.0	3.3	2.8
	Bottom 10 Avg.	2.0	2.1	2.2	2.2	2.0	2.1	2.1
7. Personal Consumption Expenditures (chained, 2005 dollars)	**CONSENSUS**	**2.7**	**2.8**	**2.7**	**2.6**	**2.5**	**2.6**	**2.4**
	Top 10 Avg.	3.4	3.3	3.2	3.1	2.9	3.2	2.8
	Bottom 10 Avg.	2.0	2.2	2.2	2.1	2.0	2.1	2.0
8. Non-Residential Fixed Investment (chained, 2005 dollars)	**CONSENSUS**	**6.0**	**5.6**	**5.2**	**4.9**	**4.5**	**5.2**	**4.4**
	Top 10 Avg.	8.4	7.6	7.3	6.7	6.4	7.3	6.2
	Bottom 10 Avg.	3.3	3.4	3.5	3.2	2.5	3.2	2.8
9. Corporate Profits, Pretax (current dollars)	**CONSENSUS**	**5.7**	**5.9**	**5.1**	**4.6**	**4.8**	**5.2**	**5.4**
	Top 10 Avg.	8.7	9.3	7.8	7.2	6.9	8.0	7.0
	Bottom 10 Avg.	2.6	2.5	2.1	1.3	2.2	2.2	3.8
		Annual Average						
10. Treasury Bills, 3-Month (percent per annum)	**CONSENSUS**	**1.3**	**2.4**	**3.2**	**3.6**	**3.7**	**2.8**	**3.7**
	Top 10 Avg.	2.8	3.9	4.5	4.8	4.7	4.2	4.7
	Bottom 10 Avg.	0.2	1.0	1.7	2.2	2.4	1.5	2.6
11. Treasury Notes, 10-Year (yield per annum)	**CONSENSUS**	**3.7**	**4.2**	**4.6**	**4.9**	**4.9**	**4.5**	**4.9**
	Top 10 Avg.	4.8	5.2	5.5	5.7	5.7	5.4	5.7
	Bottom 10 Avg.	2.6	3.1	3.6	3.9	4.0	3.4	4.0
12. Unemployment Rate (% of civilian labor force)	**CONSENSUS**	**7.2**	**6.7**	**6.4**	**6.1**	**5.9**	**6.5**	**5.8**
	Top 10 Avg.	7.8	7.5	7.3	7.0	6.8	7.3	6.8
	Bottom 10 Avg.	6.5	6.0	5.5	5.2	5.1	5.7	5.1
		Total Units, Millions						
13. Housing Starts (millions of units)	**CONSENSUS**	**1.07**	**1.22**	**1.35**	**1.43**	**1.45**	**1.31**	**1.44**
	Top 10 Avg.	1.36	1.57	1.69	1.72	1.75	1.62	1.71
	Bottom 10 Avg.	0.82	0.92	1.04	1.11	1.12	1.00	1.14
14. Total Auto & Light Truck Sales (millions of units)	**CONSENSUS**	**15.0**	**15.4**	**15.7**	**15.8**	**15.8**	**15.5**	**15.8**
	Top 10 Avg.	16.1	16.4	16.7	16.8	16.7	16.5	17.0
	Bottom 10 Avg.	14.0	14.2	14.5	14.6	14.7	14.4	14.6
		Billions of Chained, 2005 Dollars						
15. Net Exports (billions of chained, 2005 dollars)	**CONSENSUS**	**-412.6**	**-407.0**	**-411.0**	**-403.8**	**-395.6**	**-406.0**	**-379.4**
	Top 10 Avg.	-320.3	-284.7	-260.8	-223.9	-184.9	-254.9	-109.4
	Bottom 10 Avg.	-520.0	-548.5	-574.3	-577.5	-592.3	-562.5	-622.1

Long-Range Consensus U.S. Economic Projections

II. For comparison, this table includes some of the long-range consensus projections found on the preceding page, plus the latest long-range projections from the Obama Administration[1,3] and the Congressional Budget Office (CBO)[2,3].

ECONOMIC VARIABLE		YEAR 2014	2015	2016	2017	2018	Five-Year Averages 2014-18	2019-23
		Percent Change, Full Year-Over-Prior Year						
1. Real GDP (chained, 2005 dollars)	**CONSENSUS**	**3.0**	**3.0**	**2.9**	**2.8**	**2.7**	**2.9**	**2.5**
	Obama Admin.[1,3]	3.6	4.1	4.0	3.9	3.2	3.8	2.6
	CBO[2,3]	3.6	4.9	4.2	3.3	2.8	3.8	2.5
2. GDP Chained Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**
	Obama Admin.[1,3]	1.6	1.8	1.8	1.8	1.8	1.8	1.8
	CBO[2,3]	1.4	1.5	1.7	1.9	1.9	1.7	2.0
3. Nominal GDP (current dollars)	**CONSENSUS**	**5.1**	**5.2**	**5.1**	**5.0**	**4.9**	**5.1**	**4.7**
	Obama Admin.[1,3]	5.3	6.0	5.9	5.7	5.0	5.6	4.4
	CBO[2,3]	5.0	6.4	5.9	5.2	5.0	5.5	4.6
4. Consumer Price Index (for all urban consumers)	**CONSENSUS**	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**	**2.4**	**2.5**
	Obama Admin.[1,3]	2.0	2.0	2.1	2.1	2.1	2.1	2.1
	CBO[2,3]	1.5	1.7	2.0	2.2	2.3	1.9	2.3
		Annual Average						
5. Treasury Bills, 3-Month (percent per annum)	**CONSENSUS**	**1.3**	**2.4**	**3.2**	**3.6**	**3.7**	**2.8**	**3.7**
	Obama Admin.[1,3]	1.4	2.7	3.9	4.1	4.1	3.2	4.1
	CBO[2,3]	0.4	1.6	2.6	3.2	3.6	2.3	3.8
6. Treasury Notes, 10-Year (yield per annum)	**CONSENSUS**	**3.7**	**4.2**	**4.6**	**4.9**	**4.9**	**4.5**	**4.9**
	Obama Admin.[1,3]	3.9	4.4	4.7	5.0	5.1	4.6	5.2
	CBO[2,3]	2.9	3.5	4.1	4.6	4.8	4.0	5.0
7. Unemployment Rate (% of civilian labor force)	**CONSENSUS**	**7.2**	**6.7**	**6.4**	**6.1**	**5.9**	**6.5**	**5.8**
	Obama Admin.[1,3]	8.1	7.3	6.5	5.8	5.5	6.6	5.4
	CBO[2,3]	8.7	7.4	6.3	5.7	5.5	6.7	5.4

III. In this table, we compare the results of our most recent survey with those of our survey in October 2011[4].

ECONOMIC VARIABLE		YEAR 2014	2015	2016	2017	2018	Five-Year Averages 2014-18	2019-23
		Percent Change, Full Year-Over-Prior Year						
1. Real GDP (chained, 2005 dollars)	**March Consensus**	**3.0**	**3.0**	**2.9**	**2.8**	**2.7**	**2.9**	**2.5**
	October Consensus	2.9	2.9	2.9	2.7	na	na	na
2. GDP Chained Price Index	**March Consensus**	**2.1**	**2.2**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**
	October Consensus	2.1	2.1	2.1	2.2	na	na	na
3. Nominal GDP (current dollars)	**March Consensus**	**5.1**	**5.2**	**5.1**	**5.0**	**4.9**	**5.1**	**4.7**
	October Consensus	5.1	5.0	5.0	4.8	na	na	na
4. Consumer Price Index (for all urban consumers)	**March Consensus**	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**	**2.4**	**2.5**
	October Consensus	2.4	2.4	2.4	2.5	na	na	na
		Annual Average						
5. Treasury Bills, 3-Month (percent per annum)	**March Consensus**	**1.3**	**2.4**	**3.2**	**3.6**	**3.7**	**2.8**	**3.7**
	October Consensus	1.9	3.0	3.4	3.7	na	na	na
6. Treasury Notes, 10-Year (yield per annum)	**March Consensus**	**3.7**	**4.2**	**4.6**	**4.9**	**4.9**	**4.5**	**4.9**
	October Consensus	4.1	4.5	4.7	4.9	na	na	na
7. Unemployment Rate (% of civilian labor force)	**March Consensus**	**7.2**	**6.7**	**6.4**	**6.1**	**5.9**	**6.5**	**5.8**
	October Consensus	7.7	7.1	6.6	6.2	na	na	na

[1]*Budget of the United States Government, Fiscal Year 2013,* Office of Management and Budget, February 2012. [2]*The Budget and Economic Outlook: Fiscal Years 2012-2022,* Congressional Budget Office, February, 2012. [3]The Obama Administration's projections only extend through 2022, so averages for the 2019-2023 period are based on the forecast for the four-year period 2019-2022. CBO's projections only extend through 2022, so averages for the 2019-2023 period are based on the projections for the four-year period 2019-2022. [4]*Blue Chip Economic Indicators*, October 10, 2011.

Viewpoints:

A Sampling Of Views On The Economy, Financial Markets And Government Policy Excerpted From Recent Reports Issued By Our Blue Chip Panel Members And Others

Oil Prices – This Time Is Different

Barring a further surge, higher oil prices are likely to slow, but not halt, US growth.

Federal Reserve Chairman Ben Bernanke recently delivered the semi-annual *Monetary Policy Report to Congress* (the so-called "Humphrey-Hawkins" report). In his prepared statement, Mr Bernanke addressed a concern that recently has displaced concerns about Europe's sovereign debt crisis as the greatest perceived threat to the sustainability of the US recovery – rising oil prices. In February, the price of Brent crude oil averaged about $119.43/barrel (bbl), more than $11 higher than in December and nearly $16 more than in February 2011. In response, gasoline prices have also moved sharply higher, averaging $3.72/gallon (regular grade) recently, with February prices averaging roughly 37 cents higher than a year ago.

Chairman Bernanke noted that this upsurge in gasoline and oil prices "is likely to push up inflation temporarily while reducing consumers' purchasing power." Either outcome would undermine the Fed's mandate for price stability and sustainable long-run growth, while the chairman's promise "to monitor energy markets carefully" echoes past Federal Open Market Committee (FOMC) strategies for dealing with the threat posed by soaring energy costs. Recall that in July 2008 when, as we now know, the economy was in the early months of the "Great Recession," Mr Bernanke's Humphrey-Hawkins testimony advised that the FOMC "must be particularly alert to any indications, such as an erosion of longer-term inflation expectations, that the inflationary impulses from commodity prices are becoming embedded in the domestic wage- and price-setting process." In current circumstances, policymakers believe that the rise in oil prices will prove transitory and, for now at least, take some comfort from signs that "longer-term inflation expectations, as measured by surveys and financial market indicators, appear consistent with the view that inflation will remain subdued."

Similarly abrupt and steep increases in oil prices have played a key role in precipitating recessions in 1973-75, 1980-81, 1990-91, 2001 and 2008-09. Over time, however, those shocks to the relative price of oil have spurred the innovations that have led to a more efficient use of all energy inputs. Those innovations, alongside a growing use of other energy inputs, have reduced the economy's dependence on oil. For instance, the energy input from oil required to generate a dollar's worth of world real GDP has fallen by 47% since 1995.

This suggests that sudden changes in energy prices are likely to be somewhat less harmful to the economy than in the past. Moreover, unlike previous energy price "shocks," the most recent price surge has been largely confined to petroleum and its derivative products, most importantly gasoline. Thus, even as oil prices have ratcheted higher, the price of natural gas has fallen to its lowest level in a decade. The drop in natural gas prices and rise in crude oil prices will likely accelerate the growing usage of an energy source of which the US already leads the world in production. Even in the short-run, the 11-year low natural gas prices have helped households cope with higher energy prices elsewhere by lowering home heating costs this winter US households have also adjusted consumption patterns in response to higher gasoline prices, which has effectively reduced the burden posed by higher prices over time. Judging from the historical relationship between gasoline prices and vehicle miles traveled on US highways, US households begin to adjust their demand for gas with about a two-month lag. In the 12 months ended December 2011, vehicle miles driven had fallen to the lowest level since May 2009. As a result, the Energy Information Administration (EIA) has reported that weekly usage of gasoline is now back to late-2003 levels.

Simulations of a permanent, one-off upward shift in the price of oil reinforce our conjecture that the oil price effect on US GDP growth is less severe than in the past. A key assumption in our baseline forecast is that Brent crude oil prices will average about $110/bbl over 2012. With prices now somewhat above that level, we examine the impact of alternative oil price scenarios on growth in real GDP and inflation as measured by the headline chain-weighted price indexes for personal consumption expenditures (PCE). For each alternative price scenario we assume that prices change immediately by amounts ranging from -$10 to +$40 and thereafter follow the path of oil prices represented in the baseline. (Essentially, our baseline assumes a pattern of oil price change that mirrors the path implied by the futures market.) For instance, if Brent crude prices remain near February's average (about $120/bbl), our simulations indicate that real GDP growth in 2012 would be reduced by about 0.2 percentage points (pp) and that PCE inflation would rise by about 0.3pp over the four quarters ending in Q4 2012. Our simulations also indicate that a more extreme price jump that raises the 2012 price average to $150/bbl would precipitate a slight single-quarter decline in real GDP and would lower growth for the full year by 0.7pp. A price surge that severe would also raise PCE inflation by about 1.3pp, by our estimates.

It is important to note that these scenarios do not account for any feedback effects that result from the initial price rise. That is, the subsequent reduction in economic growth would in turn begin to reverse the upward pressure on prices, thereby mitigating some of the negative growth impact in later quarters. Further, these simulations indicate primarily the short-run adjustments forced on consumers by a sudden price jump and do not reflect the longer-run shifts in spending priorities away from energy intensive goods and services. For instance, when gasoline prices surged above $4/gallon during the first half of 2008, consumers abruptly curtailed purchases of light trucks and SUVs in favor of more fuel-efficient vehicles. In July 2008, when retail gasoline prices peaked, the light truck/SUV share of total sales fell to a three-month average of 45.1%, the lowest in more than a decade and far below the 53.7% average of the previous six years. Since then, the light truck/SUV share has averaged less than 50% suggesting that high fuel costs have led to a permanent shift to more fuel-efficient cars. In the first two months of 2012 the wider availability of, and tax incentives for more economical vehicles, including electric and hybrid, are enabling overall sales to remain robust in the face of soaring prices. Indeed, any tendency for higher gas prices to spur stronger new vehicle sales illustrates that the cloud of higher oil prices has its own silver lining.

David Resler, Ellen Zentner and Aichi Amemiya, Nomura Securities International, New York, NY

Lots Of Good News But Still Only Modest Growth

Recent reports on consumer spending, manufacturing activity and housing show the economy remaining surprisingly resilient to slower economic growth around the world and higher gas prices here at home. Real GDP growth was revised up to a 3.0 percent pace in the fourth quarter and the composition of growth looks a little better, with slightly stronger gains in consumer spending and a little less of a build up in inventories than first reported. Even with the revision, however, final sales still rose at a still tepid 1.1 percent, which is a shade better than the initially reported gain of 0.8 percent.

Recent revisions to the personal income data show much less deterioration during the second half of 2011. The stronger income figures slightly boosted the saving rate but still show real per capita after tax-income has fallen in two of the past three months. Real after-tax income is also down slightly on a year-to-year basis, which shows household budgets were strained even before the most recent spick in gasoline prices. Our research shows that higher gasoline prices will impact consumers the most in the South and Midwest, where incomes are lower. Rural areas, where per capita *(continued on next page)*

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incomes tend to be lower and where residents tend to commute longer distances, will be most impacted.

Given the jump in gasoline prices, the most recent batch of data for the consumer is somewhat surprising. Consumer confidence jumped 9.3 points to 70.8, which is the highest it has been since February of last year. The February survey was taken before the most recent spike in gasoline prices.

What evidence there is on consumer behavior for February has been fairly positive. Chain store sales jumped 6.7 percent from their year earlier level, which was well ahead of expectations. January's figures were revised lower, however. Motor vehicle sales soared during February, climbing to a 15.0 million unit rate, which was the strongest pace seen since March 2008. We believe an increase in fleet sales is responsible for much of the increase in motor vehicle sales over the past two month, which will show up in higher business fixed investment rather than consumer spending. The milder weather may also have provided a slight boost to vehicle sales.

Reports from the manufacturing sector have been more mixed. The advance report on durable goods orders posted a much sharper than expected 4.0 percent drop in January, following a 3.2 percent jump the prior month. Orders fell across the board and shipments also decreased. Part of the drop is likely due to the more generous depreciation that was provided for equipment put into use by December 31. That deadline likely pulled some orders and shipments forward in 2011. January's drop, however, means business fixed investment will be relatively soft in the first quarter, even with gains in February and March.

The weaker factory orders and shipments data, combined with the 0.1 percent drop in real personal consumption outlays in January caused us to slightly reduce our forecast for first quarter economic growth. We now expect real GDP to rise at a 1.6 percent pace in the first quarter and still expect the economy to grow at around a 2 percent for all of 2012.

Given the economy's still sluggish pace, we believe the Fed maintains an open mind in regard to additional quantitative easing. Growth in the neighborhood of 2 percent does not leave the economy with flexibility to adjust to shocks from Europe, the Middle East or anywhere else. The Fed would also like to get its work done in time to provide a boost to the housing market before the key spring selling season and get out of the way before the presidential election kicks into high gear.

Mark Vitner, Wells Fargo, Charlotte, NC

When The Facts Change...

A popular indicator among clients is the Economic Cycle Research Institute (ECRI) leading index. Back in September ECRI argued that a recession was "inescapable," pointing not just to their publicly released index, but to a series of other proprietary indexes. "Once the [negative] feedback loop starts," they warned, "it's more powerful than any policy response." In the past week, they were back on the airwaves, saying "our call stands": a recession is still likely in the first half of this year. Indeed, they argue, "when you look at the hard data that is used to officially date business cycle recessions, it has been getting worse, not better, despite...the consensus view of an improving economy."

We strongly disagree with ECRI's near term predictor. We believe a recession is possible at the ***end*** of this year when fiscal policy tightens dramatically. However, the negative feedback loops the ECRI worried about last fall have stopped. Like all forecasting tools, the ECRI index's predictions are sometimes wrong, and in our view this is likely one of those times.

Leading indexes are constructed by sorting through many thousands of combinations of indicators. The data are transformed and weighted to find the best combination that turns down in front of each past recession. Both the ECRI and its older cousin, the Leading Economic Indicator (LEI) consistently turn lower in front of recessions.

While the ECRI states their index is not based on any economic theory, we believe it rests on several implicit models. First, financial variables often lead recessions. This is because financial stress can undercut growth and because financial markets sometimes "sniff out" recessions in advance. Second, in a normal business cycle, some sectors tend to turn before others, reflecting overbuilding, interest sensitivity or other cyclical effects. This is the basis for including real side indicators such as new orders and building permits.

We believe there are two inherent problems with all composite leading indexes. First, like any forecasting tool, they work poorly if there is structural change in the economy. Thus, the 2008-09 recession was hard to predict because of the unusual nature of the financial shock and its initially very slow impact on the economy. This is why we believe the ECRI's index did not "predict" the recession until it had been under way for several months. Second, the methodology of constructing these indexes creates a high risk of "over fitting" the data. Since the modeler has an almost unlimited number of indicators and transformations to draw on, it is likely that some of the relationships they discover are spurious or accidental.

Plotting the "in-sample" fit or accuracy of a model is a poor gauge of a model's predictive power, in our view. It is a lot easier to predict history than the future. This is why in most modeling today, econometricians estimate the model over part of history and then test how it does for the remaining "out of sample" period. We don't have enough information to analyze the ECRI index on this basis, but a number of economists have studied the out-of-sample record of the LEI. What they found is that in real time—using the index available before the recession— the index tends to wobble in front of recessions, with no clear signal. Later, when the index is reconstructed to take into account the latest recession, the new index shows a clear decline before each recession, including the latest one. In our view, this retrofitting explains the seemingly "perfect" record of these leading indexes.

We also question ECRI claims that the economy continues to weaken. It is true that the growth in coincident indicators is slowing when measured on a year-overyear basis. For example, the official coincident index—which combines nonfarm payrolls, real personal incomes less transfers, industrial production and real manufacturing and trade sales—has slowed to just 2%. However, year-over-year calculations are in our view a misleading way to look at short term swings in the economy. We do not disagree that six months ago, when ECRI's index made the prediction, the data were very weak. Thus, for example, the six-month annualized growth in the coincident index fell to just 0.8% last summer. Since the ECRI recession prediction, however, the six-month growth rate has accelerated to 3.2%. It is clear to us that the economy has gotten better and we believe it is misleading to signal that the economy continues to weaken.

The deterioration in leading indicators last summer was mainly because of waves of financial market stress coming from Europe and weak US data due to the oil and Japan shocks. Those shocks have now faded and the risk of a near-term recession has in our view fallen back to normal levels. Unfortunately, we believe the risk of a recession rises in the second half. The sudden stop in fiscal policy at the end of the year will likely cause a sharp slowing in growth. If it is handled badly, it could cause an outright recession. However, this has nothing to do with the now out-of-date signals from last fall.

Ethan S. Harris, Bank of America-Merrill Lynch, New York, NY

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
March 12 U.S. Budget (Feb))	**13** **FOMC Meeting** Retail Sales (Feb) Business Inventories (Jan) JOLTS (Jan) Manpower Employment Survey (Q2) ABC Consumer Comfort Index Weekly Store Sales	**14** Import Prices (Feb) Mortgage Applications EIA Crude Oil Stocks	**15** Philadelphia Fed Survey (Mar) Empire State Survey (Mar) Producer Price Index (Feb) Net Long-Term TIC Flows (Jan) Weekly Jobless Claims Weekly Money Supply	**16** Consumer Price Index (Feb) Industrial Production (Feb) Consumer Sentiment (Mar, Preliminary, University of Michigan)
19 NAHB Housing Index (Mar) Chicago FRB Midwest Manufacturing Index (Jan)	**20** Housing Starts (Feb) Weekly Store Sales ABC Consumer Comfort Index	**21** Existing Home Sales (Feb) EIA Crude Oil Stocks Mortgage Applications	**22** Leading Economic Indicators (Feb) Weekly Jobless Claims Weekly Money Supply	**23** New Home Sales (Feb)
26 Chicago FRB National Activity Index (Feb) Pending Home Sales (Feb)	**27** Consumer Confidence (Mar, Conference Board) S&P/Case-Shiller Home Price Index (Jan) ABC Consumer Comfort Index Weekly Store Sales	**28** Durable Goods Orders (Feb) State Quarterly Personal Income (Q4) EIA Crude Oil Stocks Mortgage Applications	**29** Gross Domestic Product (Q4, Third Estimate) Corporate Profits (Q4) Agricultural Prices (Mar) Weekly Jobless Claims Weekly Money Supply	**30** Personal Income and Consumption (Feb) Consumer Sentiment (Mar, Final, University of Michigan) Chicago ISM (March) Empire State ISM (March)
April 2 ISM Manufacturing (Mar Construction Spending (Feb))	**3** Motor Vehicle Sales (Mar) Factory Orders (Feb) ABC Consumer Comfort Index Weekly Store Sales	**4** ISM Non-Manufacturing (Mar) ADP Employment (Mar Mortgage Applications EIA Crude Oil Stocks	**5** Chain Store Sales (Mar) Weekly Jobless Claims Weekly Money Supply	**6** Employment Report (Mar) Consumer Credit (Feb)
9 Chicago FRB Midwest Manufacturing Index (Feb)	**10** Wholesale Trade (Feb) ABC Consumer Comfort Index Weekly Store Sales	**11** Import/Export Prices (Mar) Federal Budget (Mar) Beige Book EIA Crude Oil Stocks Mortgage Applications	**12** Trade Balance (Feb) Producer Price Index (Mar) Treasury Budget (Oct) Weekly Jobless Claims Weekly Money Supply	**13** Consumer Price Index (Mar) Consumer Sentiment (Apr, Preliminary, University of Michigan)
16 Retail Sales (Mar) Business Inventories (Feb) NAHB Housing Market Index (Apr) New York FRB Manufacturing Survey (Apr) Treasury International Capital Flows (Feb)	**17** Industrial Production (Mar) Housing Starts (Mar) ABC Consumer Comfort Index Weekly Store Sales	**18** Mortgage Applications EIA Crude Oil Stocks	**19** Existing Home Sales (Mar) Leading Economic Indicators (Mar) Philadelphia Fed Index (Apr) Weekly Jobless Claims Weekly Money Supply	**20**

EXPLANATORY NOTES

For 37 years, ***Blue Chip Economic Indicators'*** monthly survey of leading business economists has provided private and public sector decision-makers timely and accurate forecasts of U.S. economic growth, inflation and a host of other critical indicators of business activity. The newsletter utilizes a standardized format that provides a fast read on the prevailing economic outlook. The survey is conducted over two days, generally beginning on the first working day of each month. Forecasts of U.S. economic activity are collected from more than 50 leading business economists each month. The newsletter is generally finished on the third day following completion of the survey and delivered to subscribers via e-mail or first class mail.

The hallmark of ***Blue Chip Economic Indicators*** is its *consensus forecasts*. Numerous studies have shown that by averaging the opinions of many experts, the resulting consensus forecasts tend to be more accurate over time than those of any single forecaster.

Annual Forecasts On pages 2 and 3 of the newsletter are individual and consensus forecasts of U.S. economic performance for this year and next. The names of the institutions that contribute forecasts to these pages are listed on the left of the page. They are ranked from top to bottom based on how fast they expect the U.S. economy to expand in the current year. Some of these institutions have one or more asterisks (*) after their names, denoting how many times they have won the annual *Lawrence R. Klein Award for Blue Chip Forecast Accuracy.*

Across the top of pages 2 and 3 is a list of the variables for which the individual cooperators have provided forecasts. Definitions and organizations that issue estimates for these variables are found at the bottom of page 3. For columns 1-9, the forecasts are for the year-over-year percent change in each variable. Columns 10-12 represent average percentage levels of the year in question. Column 15 is an inflation-adjusted dollar level, measured in billions of chained 2000 dollars. High and low forecasts from the panel members for each variable are denoted with an "H" or "L".

Immediately below the forecasts of the individual contributors are this month's consensus forecasts. The consensus is derived by averaging our panel members' forecasts for each variable. Below the consensus forecasts are averages of this month's ten highest and ten lowest forecasts for each variable. Below them are last month's consensus forecasts. To put the forecasts in context, we include four years of historical data for each variable at the bottom of page 2. Please note that these figures can change due to government revisions of previously released estimates. Below the historical data are the number of forecasts changed from a month ago for each variable, the median forecast for each variable and a diffusion index. The diffusion index serves as a leading indicator of future changes in the consensus forecast. A reading above 50% hints of future increases in the consensus; a reading below 50% hints of future declines. The diffusion index is calculated by adding to the number of forecasters who raised their forecasts for a particular variable this month, half the number of those who left their forecasts unchanged, then dividing the sum by the total number of those contributing forecasts.

Historical Annual Consensus Forecasts Page 4 contains the forecasts from previous issues for the current and subsequent year so that subscribers can see how the outlook has changed over time. Each issue also includes graphs and analysis focusing on noteworthy changes and trends in the consensus outlook.

Quarterly Forecasts Page 5 contains quarterly historical data and consensus forecasts of the U.S. economy's performance. For columns 1-7, the forecasts are for the quarter-over-quarter, seasonally-adjusted, annualized percent change in each variable. Columns 8-10 represent average percentage levels for the quarter in question. Columns 11 and 12 represent seasonally-adjusted, annualized levels for the quarter, measured in billions of inflation-adjusted dollars. As is the case on pages 2-3, the consensus quarterly forecasts on the top half of page 5 are simple averages of our contributors' forecasts. The high-10 and low-10 forecasts are averages of the 10 highest and 10 lowest forecasts for each variable. At the bottom of page 5 are additional quarterly consensus forecasts for Real GDP, GDP Price Index, Industrial Production and Consumer Price Index. These figures are produced by taking the annualized quarterly consensus forecasts found on the top of page 5 and computing a quarterly dollar value for Real GDP, and average quarterly index levels for the GDP Price Index, Industrial Production and the Consumer Price Index. We then compute a year-over-year percentage change between the relevant quarter and the corresponding quarter of the previous year.

International Forecasts Pages 6-7 contain historical data and consensus forecasts of five key economic variables for 15 of the U.S.'s largest trading partners. A list of the institutions contributing forecasts to these pages can be found at the bottom of page 7. Columns 1 and 2 are forecasts of the year-over-year percent change in inflation-adjusted economic growth and consumer price inflation for this year and next. Column 3 is each nation's estimated current account surplus or deficit, reported in billions of current U.S. dollars. Column 4 is the estimated value of each nation's currency versus the U.S. dollar at the end of this year and next. Column 5 is the estimated level of interest rates on 3-month interest rates in each nation at the end of this year and next. Immediately below this month's consensus and the highest and lowest estimates for each variable are last month's forecasts and a limited amount of historical data. The historical data may change from month-to-month due to government revisions.

Special Questions On page 14, we report on panel members' answers to our special questions. Individuals' responses to the special questions are never displayed, only consensus, top-10 and bottom-10 results. *In March and October, we publish our semi-annual, long-range surveys.* In addition to our usual forecasts for this year and next, the semiannual, long-range survey results provide subscribers with consensus forecasts of all the variables found on pages 2 and 3 for the each of the following five years, plus an average for the five-year period after that.

Blue Chip Econometric Detail With the March, June, September and December issues, subscribers also receive a four-page quarterly supplement entitled *Blue Chip Econometric Detail.* The supplement contains forecasts of an expanded list of economic and financial variables that are derived from the consensus forecasts found in *Blue Chip Economic Indicators.* Macroeconomic Advisers, LLC of St. Louis, Missouri produces this forecast detail based on a simulation of its econometric model of the U.S. economy.

Should you have questions about the contents, or methods used to produce ***Blue Chip Economic Indicators****, please contact Randell Moore at (816) 931-0131 or email him at: randy.moore@wolterskluwer.com.*

Response No. MCC-085
Attachment B

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

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BLUE CHIP FINANCIAL FORECASTS®

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TABLE OF CONTENTS

Domestic Commentary p. 1

Domestic Summary Table –Table of consensus forecasts of U.S. interest rates and key economic assumptions p. 2

International Summary Table – Table of consensus forecasts of international interest rates and foreign exchange values p. 3

International Commentary p. 3

Individual Panel Member's U.S. Forecasts – Of interest rates and key assumptions for the next six quarters p. 4-9

Individual Panel Member's International Forecasts – Of international interest rates and foreign exchange values p. 10-11

Viewpoints – A sampling of views on the economy and government policy excerpted from recent reports issued by our panel members p. 12-13

Special Questions – Results of twice annual long-range survey forecasts for the five years 2014 through 2018 and the five-year period 2019-2023. p. 14

Databank – Monthly historical data on many key indicators of economic activity p. 15

Calendar – Release dates for important upcoming economic Data, FOMC meetings, etc. p. 16

List Of Contributing Economists – To Domestic and International Survey **inside of back cover**

U.S. Growth Prospects Dim A Bit As Uncertainty About European Risks Increase

Domestic Commentary A majority of our panelists grew a bit more cautious about the pace of U.S. economic growth over the forecast horizon, according to our May 23rd-24th survey. Although the consensus continues to predict real GDP growth of 2.3% (saar) and 2.5%, respectively, in Q2 and Q3 of this year, forecasts of growth in Q4 2012 and in Q1 2013 both slipped 0.2 of a percentage point over the past month. The consensus forecasts of real GDP growth in Q2 and Q3 2013, however, remained at 2.6% and 2.9%, respectively.

Increased caution about the U.S. economic outlook likely stems from the continued mixed nature of high-frequency indicators of U.S. activity, fears of a disorderly exit from the Eurozone by Greece and the contagion to other member states that would likely result, and uncertainty about the "fiscal cliff" that looms for the U.S. at the end of this year when a multitude of tax increases and spending cuts are currently scheduled to occur. The situation in the Eurozone, in particular, has rattled financial markets over the past several weeks, sending stock prices lower, widening some credit spreads, and lifting the value of the U.S. dollar. If the events in the Eurozone spiral into a full-fledged crisis, further reductions in consensus forecasts of U.S. economic growth seem inevitable.

While the consensus outlook for GDP growth has deteriorated a bit the outlook for inflation has improved, primarily on the basis, we suspect, on falling prices for crude oil and related products, especially gasoline. Consensus forecasts of the annualized change in the Consumer Price Index (CPI) during each of the next six quarters fell this month while forecasts of the annualized change in the GDP price index slipped for three of the next six quarters.

Consensus forecasts of average short-term Treasury bill rates over the next six quarters went essentially unchanged this month but forecasts for 10-year Treasury note yields and other longer-term notes slipped once again, the declines reflecting the continued slide in market prices driven by flight-to-safety demand, coupled with a reassessment of the likely trajectory of yields given reduced expectations for both economic growth and inflation. Nonetheless, consensus projections for the federal funds rate suggest a majority of our panelists still believe the Federal Open Market Committee (FOMC) will ultimately opt to begin raising its federal funds rate target either late next year or very early in 2014. Futures markets, on the other hand, suggest an initial tightening closer to the spring or summer of 2014.

U.S. economic data released since our last survey remained mixed, still likely reflecting payback from the unseasonably mild winter that boosted the economy's performance late last year and very early this year. Nonetheless, the most recent data remains consistent with consensus expectations of near-term real GDP growth in the range of 2%-2.5%. That said, it looks as if real GDP growth in Q1 of this year will be revised down from 2.2% to the vicinity of 1.9%-2.0% given the latest readings on business inventory levels during the quarter.

GDP growth in the current quarter is expected to be characterized by an acceleration in final sales to its best pace since Q3 of last year. Personal consumption expenditures will grow a bit slower than in Q1 but growth in nonresidential fixed investment is widely predicted to be somewhat better. Residential investment will continue to grow but at perhaps half the average pace seen in the prior two quarters. Business inventories are expected to be a drag on GDP in Q2 while net exports may prove to be a small contributor. Government spending and investment likely will continue to subtract from GDP but not to the degree seen in recent quarters.

The Institute of Supply Management's manufacturing survey for April increased 1.5 points to 54.8, its highest level since last June. The rise was supported by sizable gains in the new orders and production indices. Moreover, total industrial production surged 1.1% in April, the biggest monthly increase since December 2010. However, a sizable portion of the increase was accounted for by a rebound in mining output following two months of declines, coupled with a surge in utility output as more normal temperatures boosted heating demand. In contrast to the strength in manufacturing, the ISM nonmanufacturing index for April slid 2.5 points to 53.5, its lowest level of this year. The ISM manufacturing index for May now is widely expected to slip as suggested by the Richmond Federal Reserve bank's PMI for May that dropped to 4 from 14 in April and the first release of Markit's manufacturing PMI for the U.S. which fell from 56.0 in April to 53.9 in May.

Total nonfarm payrolls grew by just 115,000 in April, the second consecutive month in which the increase fell well short of consensus expectations. Total nonfarm payrolls are currently expected to be up 150,000-160,000 in May with the unemployment rate unchanged at 8.1%, the recent decline halted by stabilization in the labor force participation rate. Total retail sales were also softer than expected in April, rising just 0.1%, the smallest monthly gain of the year. An early Easter and record-high temperatures in March likely pulled demand forward, depressing the sales increase in April. Retail sales likely registered somewhat stronger growth in May, helped by falling gasoline prices that lifted real growth in disposable personal incomes and consumer sentiment to its highest level in a couple of years.

Although new orders for durable goods eked out a 0.2% increase in April, nondefense capital goods orders excluding aircraft dropped for a second consecutive month and shipments of such goods that figure directly into GDP estimates of capital spending fell 1.4%. The figures add credence to the view that the December 2011 expiration of full expensing of capital goods purchases has led to a curtailment of business investment. The housing sector, in contrast, continued to exhibit evidence of recovery as housing starts registered an increase of 2.6% in April while sales of new and existing single-family homes posted respective monthly increases of 3.3% and 3.0%.

At the moment, the FOMC is expected to maintain its current policy stance when it meets on June 19th-20th. Minutes of its April 24th-25th meeting offered no hints that the current version of "Operation Twist" would be extended beyond its scheduled expiration at the end of this June. Nor were there any hints of additional quantitative easing. However, policymakers are expected to instruct managers to maintain the current size of the Fed's balance sheet. The FOMC also is expected to reiterate that meeting its dual mandate will likely require a fed funds rate that is kept "exceptionally low...at least through late 2014."

That said, much will depend on events in Europe, especially the outcome of Greece's June 17th elections, its possible reverberations through financial markets, and the response by European politicians and its central bankers. Should a full fledged crisis erupt in Europe, spreading its tentacles to the U.S., the Fed could employ some of the same liquidity-enhancing tools utilized during the 2008-2009 financial crisis. Odds of additional quantitative easing also would increase if the crisis became prolonged, threatening achievement of the Fed's policy goals. Coordinated Fed action with other major central banks also is a distinct probability if financial markets become unhinged. The most bullish market at present: the one in uncertainty.

Consensus Forecast Real GDP growth of 2%-2.5% is predicted by the consensus over the next four quarters with somewhat better growth thereafter. However, much depends on whether problems in Europe develop into a full-fledged crisis. Inflation expectations have eased as oil and gasoline prices have come down. Fed policy is expected to remain on hold over the bulk of the forecast horizon. However, a crisis that threatens achievement of its dual policy mandate could prompt additional non-conventional easing *(see page 2)*.

Special Questions On page 14 are results of our twice-yearly long-range forecast survey with estimates for the years 2014 through 2018 and averages for the 5-year periods 2014-2018 and 2019-2023.

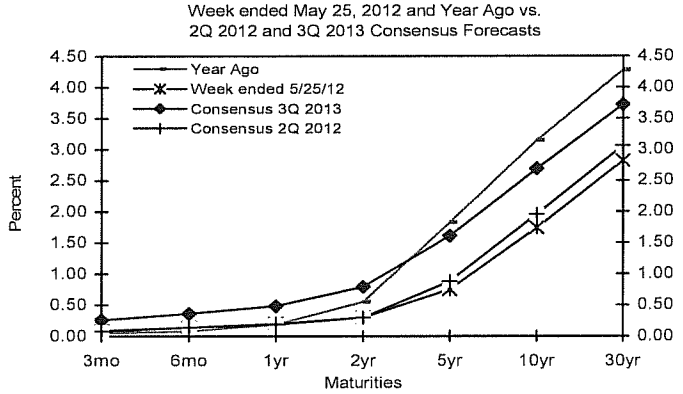
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Q	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 25	May 18	May 11	May 4	Apr.	Mar.	Feb.	1Q 2012	2012	2012	2012	2013	2013	2013
Federal Funds Rate	0.16	0.15	0.16	0.14	0.14	0.13	0.10	0.10	0.1	0.1	0.1	0.2	0.2	0.3
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.3	3.3	3.3	3.3	3.3	3.3
LIBOR, 3-mo.	0.47	0.47	0.47	0.47	0.47	0.47	0.50	0.51	0.5	0.4	0.5	0.5	0.5	0.6
Commercial Paper, 1-mo.	0.13	0.13	0.12	0.13	0.13	0.13	0.12	0.11	0.1	0.2	0.2	0.2	0.3	0.3
Treasury bill, 3-mo.	0.09	0.09	0.10	0.09	0.08	0.08	0.09	0.07	0.1	0.1	0.1	0.1	0.2	0.3
Treasury bill, 6-mo.	0.14	0.15	0.15	0.15	0.14	0.14	0.12	0.11	0.1	0.2	0.2	0.2	0.3	0.4
Treasury bill, 1 yr.	0.20	0.20	0.18	0.19	0.18	0.19	0.16	0.16	0.2	0.2	0.2	0.3	0.4	0.5
Treasury note, 2 yr.	0.30	0.30	0.27	0.27	0.29	0.34	0.28	0.29	0.3	0.3	0.4	0.5	0.6	0.8
Treasury note, 5 yr.	0.75	0.74	0.77	0.82	0.89	1.02	0.83	0.90	0.9	1.0	1.1	1.3	1.4	1.6
Treasury note, 10 yr.	1.74	1.74	1.88	1.95	2.05	2.17	1.97	2.04	2.0	2.1	2.3	2.4	2.5	2.7
Treasury note, 30 yr.	2.82	2.87	3.04	3.12	3.18	3.28	3.11	3.14	3.1	3.2	3.3	3.5	3.6	3.7
Corporate Aaa bond	3.72	3.72	3.87	3.95	3.96	3.99	3.85	3.90	3.8	3.9	4.0	4.1	4.2	4.4
Corporate Baa bond	5.02	4.98	5.08	5.15	5.19	5.23	5.14	5.20	5.1	5.1	5.2	5.3	5.4	5.5
State & Local bonds	3.81	3.75	3.71	3.81	3.95	3.91	3.66	3.75	3.8	3.9	4.0	4.1	4.2	4.3
Home mortgage rate	3.78	3.79	3.83	3.84	3.91	3.95	3.89	3.92	3.9	3.9	4.1	4.2	4.3	4.5
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2010	2010	2010	2011	2011	2011	2011	2012	2012	2012	2012	2013	2013	2013
Major Currency Index	77.6	75.9	73.0	71.9	69.6	69.9	72.4	72.9	73.8	74.2	74.4	74.5	74.5	74.8
Real GDP	3.8	2.5	2.3	0.4	1.3	1.8	3.0	2.2	2.3	2.5	2.5	2.3	2.6	2.9
GDP Price Index	1.5	1.4	1.9	2.5	2.5	2.6	0.9	1.5	1.7	2.0	1.9	2.0	2.0	2.1
Consumer Price Index	-0.3	1.4	3.0	4.5	4.4	3.1	1.3	2.5	1.9	2.1	2.1	2.2	2.2	2.4

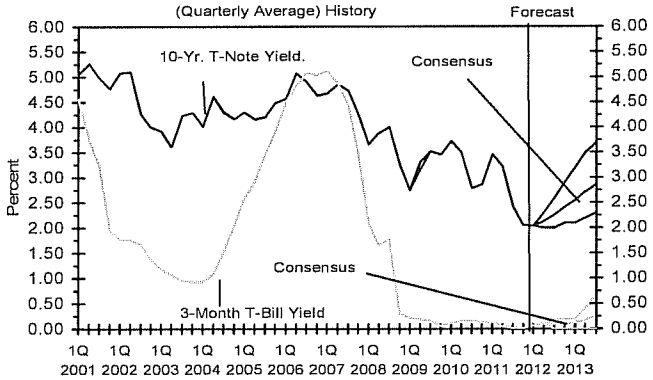
Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Interest rate definitions are the same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for the Fed's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

U.S. Treasury Yield Curve

Week ended May 25, 2012 and Year Ago vs. 2Q 2012 and 3Q 2013 Consensus Forecasts

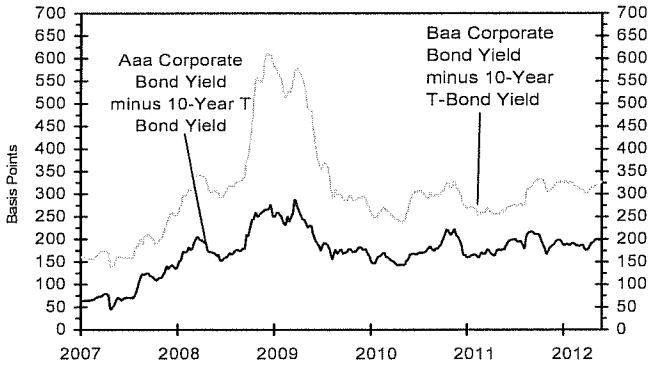


U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield



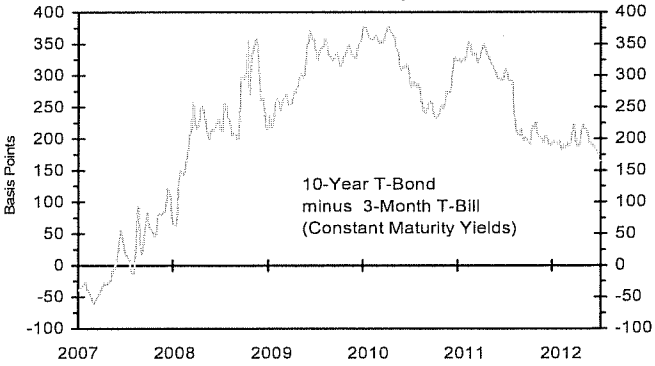
Corporate Bond Spreads

As of week ended May 25, 2012



U.S. Treasury Yield Curve

As of week ended May 25, 2012



----------3-Month Interest Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	0.66	0.36	0.38	**0.43**	**0.42**	**0.41**
Japan	0.30	0.30	0.36	**0.23**	**0.23**	**0.23**
U.K.	1.02	1.12	1.05	**0.87**	**0.81**	**0.71**
Switzerland	0.13	0.13	0.30	**0.10**	**0.10**	**0.10**
Canada	1.56	1.56	1.39	**1.30**	**1.35**	**1.87**
Australia	4.13	4.63	4.92	**4.50**	**4.40**	**4.60**
Eurozone	0.68	0.82	1.54	**0.66**	**0.66**	**0.89**

----------10-Yr. Government Bond Yields[2]------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	1.75	1.96	3.12	**2.02**	**2.25**	**2.56**
Germany	1.37	1.70	3.05	**1.79**	**1.90**	**2.13**
Japan	0.89	0.92	1.13	**1.01**	**1.05**	**1.15**
U.K.	1.75	2.10	3.35	**2.23**	**2.39**	**2.59**
France	2.53	2.99	3.47	**3.11**	**3.25**	**3.37**
Italy	5.80	5.64	4.79	**5.71**	**5.67**	**5.61**
Switzerland	0.64	0.71	1.87	**1.04**	**1.10**	**1.32**
Canada	1.80	2.07	3.12	**2.14**	**2.32**	**2.64**
Australia	3.16	3.72	5.29	**3.61**	**3.70**	**4.04**
Spain	6.33	5.84	5.47	**6.10**	**6.05**	**5.97**

----------Foreign Exchange Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	74.391	72.677	70.403	**74.9**	**75.1**	**75.1**
Japan	79.140	81.600	81.640	**82.5**	**84.5**	**86.4**
U.K.	1.5788	1.6123	1.6222	**1.57**	**1.55**	**1.58**
Switzerland	0.9442	0.9095	0.8776	**0.94**	**0.97**	**0.98**
Canada	1.0211	0.9912	0.9735	**1.00**	**1.00**	**0.99**
Australia	0.9819	1.0375	1.0644	**1.01**	**1.01**	**1.01**
Euro	1.2721	1.3212	1.4172	**1.27**	**1.24**	**1.24**

	Consensus 3-Month Rates vs. U.S. Rate			Consensus 10-Year Gov't Yields vs. U.S. Yield	
	Now	In 12 Mo.		Now	In 12
Japan	-0.36	**-0.17**	Germany	-0.38	**-0.43**
U.K.	0.36	**0.31**	Japan	-0.86	**-1.41**
Switzerland	-0.53	**-0.31**	U.K.	0.00	**0.04**
Canada	0.90	**1.46**	France	0.78	**0.82**
Australia	3.47	**4.19**	Italy	4.05	**3.06**
Eurozone	0.02	**0.48**	Switzerland	-1.11	**-1.23**
			Canada	0.05	**0.09**
			Australia	1.41	**1.48**
			Spain	4.58	**3.41**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month rate on interest-earning money market deposits denominated in selected currencies. [2]Government bonds are yields to maturity. Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.

International Commentary Rising concern that Greece may exit the euro. Deeply troubled banks in Spain. Fresh evidence of deteriorating economic activity in the broader Eurozone and UK. More modest than expected growth in China. The looming "fiscal cliff" in America. All have proved too much for financial markets over the past several weeks. Global stock markets fell, oil prices weakened, the euro dropped to a 22-month low versus the U.S. dollar, and flight-to-quality demand sent sovereign bond yields in the U.S., Germany, and the U.K. to record, or near-record lows. Official comments of support for Greece were of little solace to financial markets as preparations for a Greek exit intensified in European capitals. If Greece fails to get its act together and ultimately exits the Eurozone in a disorderly fashion, no one can speak with confidence of the consequences for financial markets and economies. Although recent polls suggest Greek parties supporting the bailout have regained favor, who is to say how long the populace would support such a government.

Even under the best of plausible circumstances surrounding Greece, the Eurozone still is confronted with a host of unresolved troubles. Among them, a Spanish banking system verging on insolvency and the likelihood that Portugal and perhaps Ireland will require additional bailouts within a year. More broadly speaking, economic activity in the currency zone is clearly worsening. The composite PMI for the Eurozone fell to 45.9 in May, the fourth straight decline and the lowest reading since June 2009 when the currency zone was last in recession. Moreover, business sentiment indices for Germany, France and Belgium each registered sharp declines in May. Due to better-than-expected growth in Germany, Eurozone real GDP was essentially unchanged in Q1 after shrinking 1.2% (saar) in Q4 2011. However, in the wake of the latest PMI readings many analysts now assume GDP in the Eurozone will contract in Q2 and quite possibly Q3 even if Germany still manages to register marginally positive growth. The worries about Greece and broader problems in the Eurozone continue to prompt talk of the need for EU political leaders to initiate the issuance of eurobonds and for the European Central Bank to cut interest rates and announce additional LTROs or some other form of liquidity enhancing provision. However, little is expected out of the ECB's June 6th meeting and any progress toward agreement on adoption of eurobonds will likely await the EU conference on June 28th-29th.

Elsewhere, real GDP in the U.K. contracted a downwardly revised 0.3% in Q1, matching its Q4 2011 decline. Moreover, many analysts anticipate a further contraction in the current quarter. While a rebound in U.K. GDP is expected in the second half of the year, much will depend on the ability of Eurozone officials to contain their sovereign debt crisis and the willingness of the Bank of England to engage in additional quantitative easing. The Reserve Bank of Australia surprised markets by cutting its cash rate by a larger-than-expected 50 basis points to 3.75% on May 1st. Somewhat softer-than-expected economic conditions and moderating inflation were cited as justifications for the rate cut by the RBA. Bank of Canada policy is widely seen as on hold for the time being. Despite its hawkish stance in response to healthy domestic demand, an actual move to remove accommodation remains stymied by uncertainty surrounding the Eurozone's debt crisis, relatively modest growth in the U.S., moderating Chinese demand for Canadian resources and the Federal Reserve's super easy policy. Nonetheless, the BoC still seems destined to become the first of the major central banks to begin tightening, it's just a matter of when. The Bank of Japan left policy unchanged at its May 23rd meeting, matching expectations for no change in its 0.0-0.1% policy rate and no change in its asset purchase target. Real GDP grew a larger-than-expected 4.1% (saar) in Q1 and growth in Q4 2011 was upwardly revised from a -0.7% contraction to a 0.1% increase. Although private consumption improved, the Q1 surge was driven by earthquake reconstruction that will likely diminish over the remainder of this year *(see pages 10-11 for individual panelists' forecasts).*

Second Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term				Long-Term				Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.5	0.2 H	0.1 H	0.1 L	0.2	0.3 L	1.1	2.3	3.4	4.3 H	5.7 H	4.0	4.2	75.0	3.1	2.6 H	1.8
Swiss Re	0.3 H	3.3	0.4	0.2 H	0.1 H	0.1 L	0.2	0.4 H	0.9	2.0	3.1	3.9	5.2	na	4.0	na	1.6	0.9	1.1
Scotiabank Group	0.3 H	3.3	na	na	0.1 H	na	na	0.3 L	0.9	2.0	3.2	na	na	na	na	na	2.2	2.0	2.7
Wells Fargo	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.8	2.9	3.9	5.1	3.8	3.8	73.8	2.2	1.8	1.5
AIG	0.2	3.3	na	na	0.1 H	0.1 L	0.2	0.3 L	0.9	2.2	3.1	3.6	4.9	na	3.7	74.4	3.8 H	0.6 L	1.3
MacroFin Analytics	0.2	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	1.8	2.9	3.8	5.0	3.9	3.8	73.4	2.1	1.5	1.8
RBS Securities	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	3.8	3.9	73.5	2.2	1.2	1.2
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.8	2.9	3.7	5.0	3.7	3.8	73.5	2.5	1.8	1.5
Nomura Securities, Inc.	0.2	3.3	0.5	0.2 H	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.1	3.8	5.1	na	3.8	73.0	2.5	1.1	1.9
Stone Harbor Investment Partners	0.2	3.3	0.5	0.2 H	0.1 H	0.2 H	0.3 H	0.3 L	0.8	1.9	3.0	3.7	5.1	na	4.0	73.0	1.7	1.8	2.1
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.3	2.5	1.8	2.3
DePrince & Assoc.	0.2	3.3	0.5	0.2 H	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	3.8	3.9	73.4	3.1	1.9	0.8
Barclays Capital	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	1.0	2.0	3.1	4.0	5.2	4.0	4.0	na	2.5	2.6 H	0.9
Naroff Economic Advisors	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	2.0	3.1	3.9	5.1	3.9	3.9	73.5	3.3	2.5	2.3
ClearView Economics	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.8	5.1	3.8	3.9	73.2	2.2	1.7	2.4
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	2.0	3.1	3.9	na	na	3.9	73.2	2.6	1.5	1.9
Fannie Mae	0.2	3.3	na	na	0.1 H	na	0.2	na	na	1.9	3.1	na	na	na	3.9	na	2.3	1.0	2.1
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.9	1.9	3.1	3.9	5.1	3.9	3.9	74.0	2.7	2.0	1.0
SunTrust Banks	0.1 L	3.3	0.5	0.2 H	0.1 H	0.2 H	0.2	0.4 H	0.9	1.9	2.9	3.9	4.9	4.3	3.4 L	74.4	2.7	1.9	2.2
Action Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.4 H	0.8	1.8	2.9	3.8	5.1	3.8	3.9	74.0	2.5	2.2	1.5
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1 H	0.1 L	0.2	0.3 L	0.8	2.0	3.2	na	na	na	na	na	1.5	na	2.3
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	2.0	3.1	3.9	5.1	3.8	3.8	72.9	2.2	0.9	1.5
GLC Financial Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	3.8	5.1	3.8	3.9	72.9	1.9	1.7	1.8
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	3.8	5.2	3.8	3.8	73.8	1.5	2.1	1.9
Economist Intelligence Unit	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	na	na	na	3.9	na	2.1	na	2.0
J.W. Coons Advisors LLC	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	na	3.8	72.5	1.5	2.3	2.5
Oxford Economics	0.1 L	3.3	0.5	na	0.0 L	0.1 L	0.2	0.3 L	0.9	2.1	3.2	na	na	na	4.0	73.3	2.3	2.0	2.9
BMO Capital Markets	0.1 L	3.3	0.5	0.2 H	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	3.9	3.8	73.5	2.3	1.4	2.3
J.P. Morgan Chase	0.1 L	na	0.5	na	0.1 H	na	na	0.3 L	0.9	2.0	3.1	na	na	na	na	na	2.5	1.2	1.3
UBS	0.1 L	na	0.5	na	0.1 H	na	na	0.4 H	0.9	2.1	3.2	na	na	na	na	na	2.0	1.5	1.3
Wells Capital Management	0.1 L	na	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	3.8	5.0	3.9	3.9	74.3	2.3	1.9	2.4
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1 H	na	na	0.3 L	0.9	2.1	3.2	na	na	na	na	na	2.0	1.8	1.3
Societe Generale	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.1 L	0.3 L	1.0	1.9	3.0	3.8	5.1	na	na	na	1.3 L	1.8	0.8
Standard & Poor's Corp.	0.1 L	3.3	0.5	0.2 H	0.1 H	0.1 L	0.2	0.3 L	0.9	2.0	na	4.0	5.2	4.0	3.9	na	2.0	1.2	1.5
Goldman Sachs & Co.	0.1 L	3.3	0.4	na	0.0 L	na	na	0.4 H	1.0	2.3	3.3	3.5	na	na	4.0	na	2.2	1.3	2.3
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.1	na	na	na	4.0	na	1.7	1.8	-0.2 L
Mesirow Financial	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.4 H	1.1	2.1	3.2	3.9	5.1	3.9	3.9	72.0 L	2.3	1.0	1.4
RDQ Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	1.2 H	2.0	3.1	3.8	5.1	3.7	3.8	73.6	2.8	2.1	1.7
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.8	2.9	3.9	5.2	3.7	3.8	74.0	2.0	1.6	1.9
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2 H	0.1 H	0.1 L	0.1 L	0.3 L	0.7 L	1.7 L	2.7 L	3.6	4.8 L	3.5	3.6	72.8	2.3	1.8	2.3
Russell Investments	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.9	1.9	2.9	3.8	5.0	3.9	3.9	73.4	2.5	1.8	2.4
Thredgold Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.7 L	1.8	2.8	3.5 L	4.8 L	3.7	3.8	74.0	2.4	1.9	2.4
RidgeWorth Investments	0.1 L	3.3	0.4	0.2 H	0.1 H	0.1 L	0.2	0.3 L	1.0	2.1	3.1	3.9	5.0	3.4 L	4.0	77.0	2.0	1.8	1.8
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	2.0	3.1	3.9	5.1	3.9	3.9	73.0	2.3	2.0	2.4
Nat'l Assn. of Realtors	0.1 L	3.3	0.4	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	1.9	2.9	3.8	5.1	3.9	3.9	na	2.3	2.4	3.0
Kellner Economic Advisers	0.1 L	3.3	0.2 L	0.2 H	0.1 H	0.1 L	0.2	0.4 H	1.0	2.1	3.1	3.9	5.0	4.5 H	3.8	78.0 H	2.2	2.0	2.2
The Northern Trust Company	0.1 L	3.3	0.2 L	na	0.1 H	na	na	0.3 L	0.9	2.0	3.1	na	na	na	na	na	2.5	2.3	2.5
Georgia State University	0.1 L	3.3	na	na	0.1 H	0.1 L	0.2	0.3 L	1.2	2.2	3.2	4.2	5.3	na	4.0	na	1.5	0.7	3.1 H
Moody's Analytics	0.1 L	3.3 L	0.5	0.2 H	0.1 H	0.2 H	0.2	0.3 L	1.0	2.4 H	3.5 H	4.2	5.4	na	4.3 H	na	2.9	2.0	1.6
June Consensus	**0.1**	**3.3**	**0.5**	**0.1**	**0.1**	**0.1**	**0.2**	**0.3**	**0.9**	**2.0**	**3.1**	**3.8**	**5.1**	**3.8**	**3.9**	**73.8**	**2.3**	**1.7**	**1.9**
Top 10 Avg.	0.2	3.3	0.5	0.2	0.1	0.2	0.2	0.4	1.1	2.2	3.3	4.0	5.3	4.0	4.0	74.9	3.0	2.3	2.6
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.2	0.3	0.8	1.8	2.9	3.7	4.9	3.7	3.7	72.9	1.6	1.0	1.0
May Consensus	0.1	3.3	0.5	0.1	0.1	0.1	0.2	0.3	1.0	2.1	3.2	4.0	5.2	3.9	4.0	73.2	2.3	1.9	2.4
Number of Forecasts Changed From A Month Ago:																			
Down	0	0	10	7	7	6	8	19	34	38	37	29	23	18	30	5	17	25	29
Same	34	44	29	22	33	27	23	23	11	9	10	7	8	5	8	8	17	14	12
Up	15	0	6	8	9	8	11	6	3	2	1	3	2	2	4	18	15	8	8
Diffusion Index	65 %	50 %	46 %	51 %	52 %	52 %	54 %	36 %	18 %	13 %	13 %	17 %	18 %	18 %	19 %	71 %	48 %	32 %	29 %

Third Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term				Long-Term				Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.5	0.2	0.1	0.1 L	0.2	0.4	1.4	2.6	3.5	4.4 H	5.9 H	4.2	4.5 H	74.0	3.3	2.8	2.8
Swiss Re	0.3 H	3.3	0.3	0.2	0.1	0.2	0.3	0.4	1.0	2.1	3.1	3.9	5.1	na	4.2	na	2.5	1.5	1.7
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.3	1.0	2.1	3.3	na	na	na	na	na	2.6	1.5	2.5
Wells Fargo	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	0.9	1.9	3.0	3.8	5.1	3.7	3.8	74.4	1.8	1.9	2.0
Russell Investments	0.2	3.3	0.4	0.2	0.1	0.2	0.2	0.3	1.1	2.0	3.1	3.9	5.2	4.1	3.9	75.0	2.8	2.0	2.3
AIG	0.2	3.3	na	na	0.1	0.1	0.2	0.3	0.9	2.4	3.3	3.7	5.0	na	3.7	75.1	3.3	0.6 L	1.2 L
Stone Harbor Investment Partners	0.2	3.3	0.5	0.2	0.2 H	0.3 H	0.4 H	0.4	0.9	2.2	3.2	4.0	5.2	na	4.0	75.0	2.4	1.6	2.3
DePrince & Associates	0.2	3.3	0.5	0.3 H	0.2 H	0.2	0.2	0.4	0.8	1.9	3.0	3.8	4.9	3.4	3.8	74.1	2.3	1.9	2.0
MacroFin Analytics	0.2	3.3	0.4	0.2	0.1	0.2	0.2	0.3	1.0	1.9	3.0	3.9	5.1	4.0	3.9	73.0	2.4	1.4	1.7
Fannie Mae	0.2	3.3	na	na	0.1	na	0.2	na	na	2.0	3.2	na	na	na	4.0	na	2.4	1.6	2.5
ClearView Economics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	0.8	1.8 L	2.8	3.8	5.0	3.8	3.8	73.7	2.5	2.0	2.4
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.0	2.1	3.2	3.9	5.2	3.9	3.9	74.5	2.5	1.6	1.5
Naroff Economic Advisors	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.4	1.0	2.2	3.3	4.1	5.3	4.0	4.0	73.5	3.7 H	2.5	2.2
RBS Securities	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.3	0.9	2.0	3.0	3.8	4.9	3.8	3.8	72.5	2.4	2.8	3.1 H
Nomura Securities, Inc.	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	3.8	5.1	na	3.8	73.5	2.6	2.3	1.4
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.4	2.7	1.8	2.2
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.2	4.0	na	na	3.9	72.9	2.4	1.9	2.3
SunTrust Banks	0.2	3.3	0.4	0.2	0.1	0.2	0.3	0.4	1.0	1.9	2.6 L	3.9	4.6 L	4.6 H	3.6 L	75.8	2.9	2.3	1.5
Barclays Capital	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	1.1	2.1	3.4	4.0	5.2	4.0	4.0	na	3.0	2.7	2.5
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.0	2.3	3.5	4.2	5.4	4.2	4.2	75.0	2.6	2.2	2.3
J.W. Coons Advisors LLC	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.4	0.9	1.9	2.9	3.9	5.1	na	3.8	72.0 L	1.9	2.2	2.5
Action Economics	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.5	1.2	2.0	3.0	3.7	5.0	3.7	3.7	74.1	2.6	1.6	1.9
Economist Intelligence Unit	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	na	na	na	3.9	na	1.8	na	2.1
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	1.1	2.1	3.3	4.0	5.2	3.8	3.8	73.8	2.2	1.6	2.3
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.4	0.9	2.1	3.2	4.0	5.4	4.0	4.0	74.5	2.6	1.8	1.4
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1	0.1 L	0.2	0.3	0.9	2.1	3.4	na	na	na	na	na	1.7	na	2.0
BMO Capital Markets	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.3	0.8	2.0	3.0	3.9	5.1	3.8	3.8	73.6	2.8	1.9	2.2
Mesirow Financial	0.1 L	3.3	0.5	0.2	0.2 H	0.2	0.3	0.5	1.2	2.3	3.5	4.2	5.3	4.2	4.1	73.0	2.4	1.6	2.4
Oxford Economics	0.1 L	3.3	0.4	na	0.0 L	0.1 L	0.1 L	0.2 L	1.1	2.2	3.4	na	na	na	4.0	74.6	2.6	3.3 H	2.1
J.P. Morgan Chase	0.1 L	na	0.5	na	0.0 L	na	na	0.3	0.9	2.0	3.1	na	na	na	na	na	3.0	1.3	1.8
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1	na	na	0.3	0.8	1.9	3.0	na	na	na	na	na	1.3 L	1.6	1.8
UBS	0.1 L	na	0.4	na	0.1	na	na	0.4	0.9	2.1	3.1	na	na	na	na	na	2.3	2.5	2.3
GLC Financial Economics	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	0.9	1.9	3.0	3.8	5.1	3.7	3.8	73.0	2.7	2.1	2.0
Societe Generale	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.1 L	0.3	1.0	2.0	3.1	3.8	4.8	na	na	na	1.8	2.1	2.2
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1	0.2	0.2	0.3	0.8	2.0	3.2	na	na	na	4.0	na	2.3	2.1	1.9
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.4	0.7 L	1.8 L	2.8	3.7	4.9	3.6	3.7	73.1	2.5	1.9	2.2
Thredgold Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.4	0.8	1.9	2.9	3.6	4.9	3.7	3.8	74.0	2.4	1.9	2.4
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	0.9	1.9	3.0	3.9	5.2	3.7	3.9	75.0	2.3	1.7	1.8
Standard & Poor's Corp.	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3	1.0	2.1	na	4.0	5.3	4.1	4.0	na	2.1	2.0	2.8
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	3.9	5.1	3.9	3.9	73.0	2.3	2.0	2.3
RDQ Economics	0.1 L	3.3	0.4	0.2	0.1	0.2	0.4 H	0.6 H	1.6 H	2.5	3.6	4.2	5.5	4.1	4.2	73.8	3.3	2.4	2.3
Nat'l Assn. of Realtors	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.4	1.1	2.0	3.1	3.9	5.2	4.0	4.0	na	3.0	2.3	2.8
RidgeWorth Investments	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3	1.0	2.2	3.2	3.9	5.0	3.2 L	4.0	76.0	2.5	1.8	1.8
Goldman Sachs	0.1 L	3.3	0.4	na	0.0 L	na	na	0.4	1.1	2.5	3.4	3.5 L	na	na	4.1	na	2.0	1.6	1.9
The Northern Trust Company	0.1 L	3.3	0.3	na	0.1	na	na	0.3	1.2	2.1	3.1	na	na	na	na	na	2.7	1.5	1.7
Kellner Economic Advisers	0.1 L	3.3	0.2 L	0.2	0.2 H	0.2	0.3	0.5	1.0	2.2	3.2	4.0	5.1	4.6 H	3.9	80.0 H	1.8	2.0	2.3
Georgia State University	0.1 L	3.3	na	na	0.0 L	0.1 L	0.1 L	0.3	1.3	2.3	3.3	4.2	5.3	na	4.1	na	1.6	1.7	1.2 L
Wells Capital Management	0.1 L	na	0.5	0.1 L	0.1	0.1 L	0.2	0.3	0.8	2.0	2.9	3.6	4.7	3.8	3.9	74.5	2.5	2.2	2.4
Moody's Analytics	0.1 L	3.3 L	0.4	0.3 H	0.1	0.2	0.3	0.5	1.3	2.8 H	3.8 H	4.4	5.7 H	na	4.5 H	na	3.3	2.3	1.8
June Consensus	**0.1**	**3.3**	**0.4**	**0.2**	**0.1**	**0.2**	**0.2**	**0.3**	**1.0**	**2.1**	**3.2**	**3.9**	**5.1**	**3.9**	**3.9**	**74.2**	**2.5**	**2.0**	**2.1**
Top 10 Avg.	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.2	2.4	3.5	4.2	5.4	4.2	4.2	75.6	3.2	2.6	2.6
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.1	0.3	0.8	1.9	2.9	3.7	4.9	3.6	3.7	73.0	1.8	1.4	1.5
May Consensus	0.1	3.3	0.4	0.2	0.1	0.1	0.2	0.4	1.1	2.3	3.4	4.1	5.3	4.0	4.1	73.2	2.5	2.0	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	0	9	5	6	3	6	17	31	35	36	31	26	19	29	3	12	16	24
Same	35	44	30	23	36	27	27	23	14	12	11	7	9	9	9	10	26	22	16
Up	11	0	6	9	7	11	9	8	3	2	1	1	2	1	4	18	11	9	9
Diffusion Index	58 %	50 %	47 %	55 %	51 %	60 %	54 %	41 %	21 %	16 %	14 %	12 %	18 %	19 %	20 %	74 %	49 %	43 %	35 %

Fourth Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term							Intermediate-Term				Long-Term				Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.6	0.2	0.1	0.1 L	0.2	0.7	1.7	2.9	3.7	4.6	6.0 H	4.4	4.8	72.0	3.5	3.0 H	2.6
Swiss Re	0.3 H	3.3	0.3 L	0.2	0.1	0.2	0.3	0.5	1.1	2.2	3.2	4.0	5.0	na	4.3	na	2.7	1.6	1.8
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.5	1.4	2.6	3.8	na	na	na	na	na	2.6	1.5	2.4
DePrince & Assoc.	0.2	3.3	0.6	0.4 H	0.2	0.3 H	0.3	0.6	0.9	2.0	3.1	3.8	4.8	3.3	3.9	74.1	2.6	1.9	2.1
Stone Harbor Investment Partners	0.2	3.3	0.6	0.3	0.2	0.3 H	0.5 H	0.5	1.1	2.4	3.4	4.1	5.1	na	4.0	76.0	1.8	2.2	2.8
Wells Fargo	0.2	3.3	0.5	0.2	0.2	0.3 H	0.3	0.4	0.9	2.0	3.1	4.0	5.2	3.8	3.9	74.9	2.1	2.1	1.7
Naroff Economic Advisors	0.2	3.3	0.5	0.2	0.2	0.3 H	0.3	0.5	1.3	2.4	3.6	4.4	5.5	4.2	4.2	72.5	4.3 H	2.6	2.6
Russell Investments	0.2	3.3	0.4	0.2	0.1	0.3 H	0.2	0.4	1.3	2.2	3.3	4.0	5.3	4.2	4.0	75.3	2.2	2.2	2.2
Kellner Economic Advisers	0.2	3.3	0.3 L	0.3	0.3 H	0.3 H	0.4	0.6	1.2	2.3	3.3	4.1	5.2	4.7 H	3.9	82.0 H	1.5	1.8	2.4
Fannie Mae	0.2	3.3	na	na	0.2	na	0.2	na	na	2.1	3.2	na	na	na	4.0	na	2.4	1.6	2.2
AIG	0.2	3.3	na	na	0.1	0.1 L	0.2	0.3	0.9	2.6	3.6	3.8	5.1	na	3.9	75.2	3.3	0.8 L	1.5
ClearView Economics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	74.1	2.8	2.3	2.6
SunTrust Banks	0.2	3.3	0.4	0.2	0.1	0.2	0.3	0.4	0.9	1.7 L	2.5 L	3.8	4.5	4.5	3.4 L	77.3	3.1	2.0	2.5
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.1	2.2	3.3	4.0	5.3	4.0	4.0	75.0	1.0 L	1.6	1.6
RBS Securities	0.2	3.3	0.5	0.2	0.1	0.2	0.2	0.3	0.9	2.0	3.0	3.5 L	4.5 L	3.8	3.7	71.5 L	2.8	1.9	2.5
Nomura Securities, Inc.	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.3	1.1	2.1	3.3	4.0	5.3	na	3.9	74.5	2.1	2.6	1.6
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.2	1.9	1.8	2.0
MacroFin Analytics	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.4	1.1	2.0	3.1	4.0	5.2	4.1	4.0	73.5	2.8	1.3	1.7
Mesirow Financial	0.2	3.3	0.4	0.2	0.2	0.3 H	0.3	0.6	1.4	2.6	3.7	4.4	5.5	4.4	4.4	74.0	2.5	1.4	1.5
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	1.0	2.2	3.3	4.1	na	na	4.0	72.5	2.1	1.4	2.2
Barclays Capital	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	1.0	2.0	3.4	4.0	5.2	4.0	4.0	na	3.0	2.7	2.5
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.5	1.4	2.9	4.3 H	4.7 H	5.9	4.7 H	4.8	76.0	3.1	2.4	3.1 H
J.W. Coons Advisors LLC	0.1 L	3.3	0.7 H	0.2	0.2	0.3 H	0.3	0.5	1.0	2.0	3.0	4.0	5.2	na	3.8	71.5 L	2.0	2.2	2.5
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1	0.1 L	0.2	0.3	1.0	2.3	3.7	na	na	na	na	na	1.1	na	2.0
Economist Intelligence Unit	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.0	2.1	3.2	na	na	na	4.0	na	2.2	na	2.3
Action Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.7	1.4	2.2	3.2	3.7	5.1	3.6	3.6	73.9	2.7	2.2	2.8
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	1.3	2.3	3.3	4.1	5.3	3.9	3.9	74.7	2.3	1.3	2.0
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.5	1.0	2.2	3.2	4.0	5.4	4.1	4.0	75.0	2.6	1.9	2.1
BMO Capital Markets	0.1 L	3.3	0.4	0.2	0.1	0.2	0.2	0.4	1.0	2.3	3.4	4.1	5.2	3.9	4.2	74.2	2.9	1.4	1.7
Oxford Economics	0.1 L	3.3	0.4	na	0.0 L	0.1 L	0.1 L	0.2 L	1.2	2.2	3.6	na	na	na	4.1	75.0	2.9	2.8	1.9
J.P. Morgan Chase	0.1 L	na	0.5	na	0.0 L	na	na	0.3	1.2	2.4	3.5	na	na	na	na	na	2.0	1.3	1.6
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1	na	na	0.3	0.9	2.3	3.6	na	na	na	na	na	1.0	1.5	2.0
UBS	0.1 L	na	0.4	na	0.2	na	na	0.5	1.2	2.3	3.4	na	na	na	na	na	2.8	2.0	0.5 L
GLC Financial Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.4	0.9	2.0	3.1	3.9	5.1	3.8	4.0	73.2	2.6	2.0	2.2
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1	0.2	0.2	0.3	1.0	2.2	3.5	na	na	na	4.0	na	2.7	2.2	2.0
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.4	0.8 L	1.9	3.0	3.9	5.1	3.8	3.9	73.4	2.5	2.0	2.1
Thredgold Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.4	0.9	2.0	3.0	3.6	4.9	3.8	3.9	74.0	2.6	2.0	2.4
Nat'l Assn. of Realtors	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.6	1.3	2.4	3.4	4.1	5.3	4.1	4.2	na	2.9	2.2	2.7
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.5	1.0	2.0	3.1	4.0	5.3	3.8	3.9	76.0	2.5	1.8	2.0
Standard & Poor's Corp.	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.4	1.0	2.2	na	4.1	5.2	4.1	4.0	na	2.3	1.4	1.4
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	1.0	2.1	3.2	4.0	5.3	3.9	3.9	73.0	2.3	2.2	2.3
RDQ Economics	0.1 L	3.3	0.4	0.2	0.1	0.2	0.5 H	0.8 H	1.9 H	3.0	4.1	4.6	5.9	4.6	4.7	73.9	3.3	2.7	2.8
RidgeWorth Investments	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3	1.0	2.2	3.3	3.8	4.8	3.1 L	4.0	74.0	2.5	1.9	1.8
Goldman Sachs & Co.	0.1 L	3.3	0.3 L	na	0.0 L	na	na	0.5	1.2	2.5	3.4	3.5 L	na	na	4.1	na	2.5	1.5	1.4
The Northern Trust Company	0.1 L	3.3	0.3 L	na	0.1	na	na	0.3	1.2	2.5	3.6	na	na	na	na	na	na	na	na
Georgia State University	0.1 L	3.3	na	na	0.0	0.1 L	0.1 L	0.4	1.3	2.4	3.3	4.2	5.3	na	4.1	na	1.7	1.5	1.6
Societe Generale	0.1 L	3.3	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.0	2.2	3.3	3.9	4.8	na	na	na	2.6	2.1	2.2
Wells Capital Management	0.1 L	na	0.5	0.2	0.1	0.2	0.3	0.3	1.0	2.1	3.1	3.7	4.8	3.9	4.1	74.5	2.6	2.1	2.1
Moody's Analytics	0.1 L	3.3 L	0.5	0.3	0.1	0.2	0.3	0.6	1.7	3.2 H	4.2	4.6	5.9	na	4.9 H	na	1.8	2.3	2.1
June Consensus	**0.1**	**3.3**	**0.5**	**0.2**	**0.1**	**0.2**	**0.2**	**0.4**	**1.1**	**2.3**	**3.3**	**4.0**	**5.2**	**4.0**	**4.1**	**74.4**	**2.5**	**1.9**	**2.1**
Top 10 Avg.	0.2	3.3	0.6	0.2	0.2	0.3	0.4	0.6	1.5	2.7	3.8	4.4	5.6	4.4	4.5	76.3	3.2	2.6	2.7
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.1	0.2	0.3	0.9	1.9	3.0	3.7	4.8	3.7	3.8	72.7	1.6	1.3	1.4
May Consensus	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.4	1.2	2.4	3.5	4.2	5.4	4.1	4.2	73.3	2.7	2.0	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	1	0	7	4	4	1	8	12	30	32	33	29	25	18	28	4	20	13	17
Same	38	44	32	28	37	31	27	28	17	13	12	9	10	10	10	10	25	24	22
Up	10	0	6	5	8	9	7	8	1	4	3	1	2	1	4	17	3	9	9
Diffusion Index	59 %	50 %	49 %	51 %	54 %	60 %	49 %	46 %	20 %	21 %	19 %	14 %	19 %	21 %	21 %	71 %	32 %	46 %	42 %

First Quarter 2013

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term							Intermediate-Term				Long-Term				Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Russell Investments	0.3 H	3.3 H	0.4	0.2	0.2	0.3	0.4	0.6	1.5	2.4	3.4	4.1	5.4	4.3	4.2	74.7	1.5	2.2	2.5
Kellner Economic Advisers	0.3 H	3.3	0.4	0.4 H	0.4 H	0.4 H	0.5	0.7	1.4	2.4	3.4	4.2	5.3	4.8	4.1	83.0 H	2.5	2.5	2.6
J.W. Coons Advisors LLC	0.3 H	3.3	0.7 H	0.3	0.3	0.4	0.5	0.6	1.2	2.1	3.1	4.1	5.3	na	3.9	71.6	1.6	2.2	2.5
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3	0.6	0.2	0.1	0.1 L	0.2	1.3 H	1.9	3.1	3.8	4.7	6.1	4.5	5.0	71.0	2.8	2.9 H	2.5
Swiss Re	0.3 H	3.3	0.3 L	0.2	0.1	0.2	0.3	0.5	1.1	2.2	3.2	4.0	5.0	na	4.3	na	2.7	1.6	1.8
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.6	1.5	2.8	3.9	na	na	na	na	na	2.2	1.8	2.3
DePrince & Assoc.	0.2	3.3	0.6	0.3	0.2	0.3	0.4	0.6	1.1	2.1	3.2	4.0	4.9	3.3	4.1	73.9	2.6	1.9	2.2
Naroff Economic Advisors	0.2	3.3	0.5	0.2	0.3	0.3	0.4	0.7	1.5	2.6	3.7	4.6	5.7	4.4	4.4	71.0 L	2.8	2.8	2.5
Stone Harbor Investment Partners	0.2	3.3	0.5	0.3	0.2	0.3	0.5	0.7	1.4	2.7	3.7	4.4	5.2	na	4.2	75.0	2.3	1.9	2.7
Wells Fargo	0.2	3.3	0.4	0.2	0.2	0.3	0.4	0.5	1.0	2.1	3.2	4.0	5.2	3.9	3.9	75.4	1.7	2.1	1.7
Fannie Mae	0.2	3.3	na	na	0.2	na	0.2	na	na	2.2	3.2	na	na	na	4.1	na	2.3	1.7	2.1
SunTrust Banks	0.2	3.3	0.4	0.2	0.1	0.2	0.3	0.4	0.8 L	1.5 L	2.3 L	3.7	4.6	4.4	3.2 L	78.9	3.3	1.5	2.0
AIG	0.2	3.3	na	na	0.1	0.1 L	0.2	0.3	0.9	2.6	3.6	3.9	5.1	na	4.0	75.1	3.0	1.1 L	1.2 L
ClearView Economics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3 L	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	74.8	3.1	2.5	2.7
Mesirow Financial	0.2	3.3	0.4	0.2	0.3	0.3	0.4	0.8	1.6	2.9	4.0	4.7	5.7	4.4	4.7	74.9	2.2	2.0	2.2
Pierpont Securities	0.2	3.3	0.6	0.2	0.1	0.2	0.3	0.8	1.8	3.6 H	5.0 H	5.3 H	6.5 H	5.4 H	5.6 H	77.0	3.5 H	2.8	3.3
Nomura Securities, Inc.	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.4	1.2	2.2	3.3	4.0	5.3	na	3.9	74.5	1.9	2.8	1.4
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.2	2.4	3.5	4.2	5.4	4.1	4.2	75.0	1.0 L	1.5	1.6
RBS Securities	0.2	3.3	0.5	0.2	0.1	0.2	0.2	0.3 L	0.9	2.0	3.0	3.3 L	4.3 L	3.8	3.6	73.0	2.4	2.4	2.5
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3 L	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.0	1.5	2.0	2.2
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.4	1.1	2.3	3.4	4.2	na	na	4.1	72.4	2.9	1.7	2.2
Barclays Capital	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3 L	1.0	2.0	3.4	4.0	5.2	4.0	4.0	na	2.0	2.7	2.3
Economist Intelligence Unit	0.1 L	3.3	0.6	0.2	0.1	0.2	0.2	0.4	1.2	2.2	3.5	na	na	na	4.3	na	1.6	na	2.6
MacroFin Analytics	0.1 L	3.3	0.5	0.2	0.2	0.2	0.3	0.4	1.2	2.1	3.2	4.2	5.3	4.2	4.2	74.0	2.5	1.2	1.6
Action Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.6 H	0.9	1.7	2.4	3.5	3.8	5.1	3.6	3.7	73.7	2.3	2.0	3.3 H
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.3 L	1.3	2.3	3.3	4.1	5.3	3.3	3.9	74.9	1.7	1.9	2.2
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.5	1.1	2.3	3.3	4.1	5.4	4.1	4.0	75.3	2.3	1.8	2.0
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1	0.1 L	0.2	0.4	1.1	2.4	3.8	na	na	na	na	na	na	na	na
BMO Capital Markets	0.1 L	3.3	0.4	0.2	0.1	0.2	0.3	0.5	1.2	2.6	3.6	4.3	5.4	4.0	4.6	74.3	1.8	1.9	2.2
Oxford Economics	0.1 L	3.3	0.4	na	0.0 L	0.1 L	0.2	0.4	1.4	2.4	3.8	na	na	na	4.2	75.3	2.5	2.5	2.0
J.P. Morgan Chase	0.1 L	na	0.5	na	0.0 L	na	na	0.3 L	1.3	2.5	3.6	na	na	na	na	na	1.5	1.4	1.7
UBS	0.1 L	na	0.5	na	0.2	na	na	0.6	1.4	2.5	3.6	na	na	na	na	na	2.8	2.0	1.3
GLC Financial Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.4	1.0	2.1	3.2	4.0	5.2	3.9	4.1	73.1	2.0	2.4	2.4
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1	0.2	0.2	0.3 L	1.2	2.5	3.7	na	na	na	4.4	na	1.8	1.8	2.3
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.4	0.9	2.1	3.1	4.0	5.1	3.9	4.0	74.0	2.3	2.1	2.2
Thredgold Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.1	2.0	3.0	3.6	4.9	3.8	3.9	74.0	2.8	2.0	2.4
Nat'l Assn. of Realtors	0.1 L	3.3	0.5	0.2	0.2	0.3	0.5	0.8	1.8	2.8	3.7	4.4	5.6	4.4	4.3	na	2.8	2.2	2.7
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.6	1.1	2.1	3.2	4.0	5.3	3.9	4.0	76.0	3.0	1.9	2.0
Moody's Analytics	0.1 L	3.3	0.5	0.3	0.1	0.2	0.4	0.7	2.1	3.5	4.4	4.8	6.1	na	5.1	na	2.9	2.1	2.1
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.3	0.4	1.1	2.4	3.5	4.2	5.5	4.0	4.0	73.0	1.5	2.3	2.5
RDQ Economics	0.1 L	3.3	0.4	0.2	0.1	0.2	0.6 H	0.9	2.1 H	3.3	4.5	4.9	6.1	5.0	5.0	74.0	3.2	2.9 H	3.3 H
RidgeWorth Investments	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3 L	1.1	2.2	3.3	3.7	4.7	2.6 L	4.0	73.0	3.0	2.0	2.4
Goldman Sachs & Co.	0.1 L	3.3	0.3 L	na	0.0 L	na	na	0.5	1.3	2.6	3.5	3.5	na	na	4.1	na	2.0	1.3	1.7
Georgia State University	0.1 L	3.3	na	na	0.0 L	0.1 L	0.1 L	0.4	1.4	2.6	3.5	4.3	5.3	na	4.2	na	2.3	1.6	1.7
Societe Generale	0.1 L	3.3	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.1	2.3	3.3	4.0	4.9	na	na	na	1.2	1.9	1.3
Standard & Poor's Corp.	0.1 L	3.3 L	0.4	0.2	0.1	0.1 L	0.2	0.4	1.1	2.3	na	4.1	5.1	4.0	4.1	na	2.2	1.4	1.7
Wells Capital Management	0.1 L	na	0.6	0.2	0.1	0.2	0.3	0.4	1.1	2.4	3.4	3.9	4.9	4.1	4.4	74.5	2.8	2.1	2.4
June Consensus	**0.2**	**3.3**	**0.5**	**0.2**	**0.1**	**0.2**	**0.3**	**0.5**	**1.3**	**2.4**	**3.5**	**4.1**	**5.3**	**4.1**	**4.2**	**74.5**	**2.3**	**2.0**	**2.2**
Top 10 Avg.	0.2	3.3	0.6	0.3	0.2	0.3	0.5	0.8	1.7	3.0	4.0	4.6	5.8	4.6	4.7	76.6	3.1	2.7	2.8
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.2	0.3	0.9	2.0	3.0	3.7	4.8	3.6	3.8	72.6	1.5	1.4	1.5
May Consensus	0.1	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.4	2.6	3.7	4.3	5.5	4.2	4.3	73.3	2.5	2.1	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	0	7	6	4	2	11	14	26	30	29	28	22	14	27	2	21	12	15
Same	34	43	30	24	34	30	27	25	18	15	14	10	11	13	10	13	20	22	24
Up	10	0	6	7	9	9	4	7	2	2	3	1	4	2	5	16	5	11	7
Diffusion Index	57 %	50 %	49 %	51 %	55 %	59 %	42 %	42 %	24 %	20 %	22 %	15 %	26 %	29 %	24 %	73 %	33 %	49 %	41 %

Second Quarter 2013

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	Long-Term: 12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.8 H	3.8 H	1.2 H	0.9 H	0.9 H	1.0 H	1.2 H	2.0 H	2.4	3.2	3.9	5.0	6.3	4.5	5.0	72.0	3.4	2.8	2.7
J.W. Coons Advisors LLC	0.6	3.6	1.0	0.6	0.5	0.7	0.8	0.9	1.5	2.2	3.2	4.3	5.5	na	4.1	71.3	2.1	2.1	2.5
Kellner Economic Advisers	0.4	3.4	0.5	0.5	0.5	0.5	0.7	0.8	1.6	2.5	3.5	4.3	5.4	4.9	4.3	84.0 H	3.0	2.7	2.8
Thredgold Economics	0.3	3.5	0.6	0.4	0.3	0.4	0.5	0.7	1.2	2.1	3.0	3.6	4.9	3.9	4.0	74.0	3.0	2.1	2.4
Russell Investments	0.3	3.3 L	0.5	0.2	0.3	0.4	0.5	0.8	1.7	2.7	3.5	4.3	5.4	4.4	4.2	74.9	2.1	2.3	2.2
Stone Harbor Investment Partners	0.3	3.3 L	0.5	0.5	0.2	0.4	0.6	0.8	1.7	3.0	4.0	4.7	5.5	na	4.4	73.0	2.5	2.0	2.5
Naroff Economic Advisors	0.3	3.3 L	0.5	0.3	0.3	0.4	0.5	0.7	1.7	2.7	3.9	4.8	5.9	4.5	4.5	68.0 L	2.6	2.6	2.8
Moody's Capital Markets Group	0.3	3.3 L	0.5	0.3	0.2	0.3	0.4	0.6	1.2	2.3	3.3	4.1	5.3	4.1	4.1	75.5	2.8	1.9	2.1
Swiss Re	0.3	3.3 L	0.3 L	0.2	0.1	0.2	0.3	0.8	1.5	2.4	3.3	4.2	4.9	na	4.3	na	2.9	2.1	2.3
Scotiabank Group	0.3	3.3 L	na	na	0.2	na	na	0.7	1.7	3.0	4.0	na	na	na	na	na	2.4	1.8	2.2
SunTrust Banks	0.2	3.3 L	0.4	0.2	0.1	0.3	0.4	0.5	0.9	1.6 L	2.3 L	3.8	4.6	4.4	3.3 L	80.4	2.8	1.8	2.3
DePrince & Associates	0.2	3.3 L	0.6	0.4	0.2	0.3	0.5	0.7	1.3	2.4	3.4	4.2	5.1	3.5	4.3	74.2	2.9	1.9	2.2
Wells Fargo	0.2	3.3 L	0.4	0.2	0.2	0.3	0.4	0.6	1.1	2.2	3.3	4.1	5.3	3.9	4.0	72.3	2.0	2.1	1.9
Cycledata Corp.	0.2	3.3 L	0.4	0.2	0.2	0.2	0.5	0.7	1.5	2.6	3.7	4.5	5.8	4.2	4.2	73.0	1.7 L	2.4	2.6
Fannie Mae	0.2	3.3 L	na	na	0.3	na	0.2	na	na	2.2	3.3	na	na	na	4.2	na	2.2	1.6	1.9
Pierpont Securities	0.2	3.3 L	0.8	0.2	0.2	0.4	0.6	1.5	2.8 H	4.2 H	5.6 H	5.8 H	7.0 H	5.9 H	6.2 H	80.0	3.8 H	2.6	3.5 H
AIG	0.2	3.3 L	na	na	0.1	0.1 L	0.2	0.3 L	0.9	2.8	3.8	4.1	5.3	na	4.2	75.1	2.9	0.7 L	1.2
Mesirow Financial	0.2	3.3 L	0.4	0.2	0.3	0.4	0.5	0.9	1.8	3.1	4.1	4.9	5.8	4.5	4.9	73.9	2.5	1.1	1.5
ClearView Economics	0.2	3.3 L	0.4	0.1 L	0.1	0.2	0.2	0.3 L	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	75.2	3.4	2.5	2.8
Nomura Securities, Inc.	0.2	3.3 L	0.6	0.2	0.1	0.1 L	0.2	0.4	1.2	2.2	3.4	4.0	5.4	na	4.0	74.5	2.1	2.3	1.7
MacroFin Analytics	0.2	3.3 L	0.5	0.2	0.2	0.2	0.5	0.5	1.3	2.2	3.3	4.2	5.4	4.3	4.2	74.5	2.7	1.3	1.6
Woodworth Holdings	0.2	3.3 L	0.5	0.1 L	0.1	0.2	0.3	0.5	1.3	2.4	3.5	4.2	5.5	4.2	4.2	76.0	2.0	1.5	1.5
JPMorgan Private Banking	0.2	3.3 L	0.5	0.1 L	0.1	0.2	0.2	0.3 L	0.9	2.0	3.1	3.9	5.2	3.9	3.9	73.5	1.9	1.9	2.1
RBS Securities	0.2	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	0.9	2.0	3.0	3.2 L	4.1 L	3.8	3.6	73.5	2.5	2.0	2.2
Chmura Economics & Analytics	0.2	3.3 L	0.4	0.2	0.1	0.2	0.2	0.4	1.2	2.4	3.5	4.3	na	na	4.1	72.2	3.3	2.1	1.8
Economist Intelligence Unit	0.1 L	3.3 L	0.6	0.2	0.1	0.2	0.2	0.6	1.4	2.4	3.7	na	na	na	4.4	na	2.0	na	1.8
Action Economics	0.1 L	3.3 L	0.5	0.2	0.2	0.4	0.8	1.2	1.9	2.7	3.7	3.8	5.2	3.7	3.7	73.6	2.5	2.3	3.3
RBC Capital Markets	0.1 L	3.3 L	0.5	na	0.1	0.1 L	0.2	0.5	1.3	2.6	3.9	na	na	na	na	na	na	na	na
Loomis, Sayles & Company	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.2	0.3 L	1.3	2.4	3.4	4.1	5.2	3.8	4.0	74.9	2.3	1.6	2.0
Oxford Economics	0.1 L	3.3 L	0.4	na	0.0 L	0.1 L	0.3	0.6	1.4	2.4	3.9	na	na	na	4.3	75.7	2.7	2.2	1.9
BMO Capital Markets	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.4	0.6	1.4	2.8	3.8	4.4	5.5	4.0	4.9	73.9	2.6	2.2	2.6
UBS	0.1 L	na	0.6	na	0.4	na	na	0.7	1.6	2.6	3.7	na	na	na	na	na	2.7	2.0	1.4
GLC Financial Economics	0.1 L	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	1.0	2.1	3.3	4.1	5.4	3.9	4.2	73.1	2.9	2.7	2.4
Moody's Analytics	0.1 L	3.3 L	0.6	0.4	0.2	0.3	0.4	0.8	2.6	3.6	4.5	5.0	6.2	na	5.5	na	3.7	2.1	2.1
Comerica Bank	0.1 L	3.3 L	0.7	na	0.1	0.2	0.2	0.4	1.3	2.6	3.8	na	na	na	4.7	na	2.0	2.3	2.1
Wintrust Wealth Management	0.1 L	3.3 L	0.6	0.2	0.1	0.2	0.2	0.5	1.0	2.2	3.2	4.1	5.2	3.9	4.1	74.3	2.4	1.9	2.4
Nat'l Assn. of Realtors	0.1 L	3.3 L	0.6	0.3	0.3	0.4	0.7	1.1	2.3	3.0	3.9	4.6	5.7	4.5	4.4	na	2.6	2.3	2.8
Daiwa Capital Markets America	0.1 L	3.3 L	0.5	0.1 L	0.1	0.2	0.2	0.8	1.3	2.3	3.4	4.1	5.4	4.1	4.1	76.0	3.1	2.0	2.2
RDQ Economics	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.6	1.0	2.3	3.5	4.7	5.0	6.2	5.1	5.2	74.1	3.3	3.0 H	3.4
RidgeWorth Investments	0.1 L	3.3 L	0.4	0.2	0.1	0.1 L	0.2	0.3 L	1.1	2.2	3.3	3.7	4.7	2.6 L	4.0	72.0	3.0	2.2	2.2
Goldman Sachs & Co.	0.1 L	3.3 L	0.3 L	na	0.0 L	na	na	0.6	1.4	2.8	3.6	3.7	na	na	4.3	na	2.0	1.3	1.7
Georgia State University	0.1 L	3.3 L	na	na	0.0	0.1 L	0.1 L	0.4	1.5	2.7	3.6	4.4	5.4	na	4.2	na	2.4	0.9	1.6
Wells Capital Management	0.1 L	na	0.6	0.3	0.2	0.3	0.4	0.5	1.2	2.7	3.5	4.1	4.9	4.3	4.7	74.8	3.0	2.2	2.6
Societe Generale	0.1 L	3.3 L	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.1	2.3	3.3	4.0	4.9	na	na	na	1.7 L	2.0	1.8
Standard & Poor's Corp.	0.1 L	3.3 L	0.4	0.2	0.1	0.1 L	0.2	0.4	1.4	2.6	na	4.3	5.4	4.2	4.4	na	2.4	0.9	1.1 L
June Consensus	**0.2**	**3.3**	**0.5**	**0.3**	**0.2**	**0.3**	**0.4**	**0.6**	**1.4**	**2.5**	**3.6**	**4.2**	**5.4**	**4.2**	**4.3**	**74.5**	**2.6**	**2.0**	**2.2**
Top 10 Avg.	0.4	3.4	0.7	0.4	0.4	0.5	0.7	1.1	2.1	3.2	4.2	4.9	6.0	4.7	5.0	77.3	3.3	2.6	2.9
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.2	0.3	1.0	2.0	3.1	3.7	4.8	3.7	3.8	72.0	2.0	1.3	1.5
May Consensus	0.2	3.3	0.5	0.2	0.2	0.3	0.4	0.7	1.5	2.7	3.8	4.4	5.6	4.3	4.4	73.3	2.6	2.0	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	4	0	8	7	4	3	10	12	25	30	28	24	19	14	23	3	15	11	12
Same	33	40	26	23	33	28	25	24	18	14	16	11	15	10	13	13	17	22	24
Up	8	2	6	5	8	9	6	8	1	1	0	3	1	3	5	13	12	10	8
Diffusion Index	54 %	52 %	48 %	47 %	54 %	58 %	45 %	45 %	23 %	18 %	18 %	22 %	24 %	30 %	28 %	67 %	47 %	49 %	45 %

Third Quarter 2013

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
	Percent Per Annum -- Average For Quarter															Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
Bank of Toyko-Mitsubishi UFJ	1.3 H	4.3 H	1.6 H	1.4 H	1.4 H	1.5 H	1.7 H	2.5 H	3.0	3.4	4.3	5.3	6.5	4.6	5.1	72.0	3.2	3.0	2.9
J.W. Coons Advisors LLC	0.9	3.9	1.4	0.9	0.8	0.9	1.0	1.2	1.7	2.4	3.3	4.7	5.6	na	4.2	70.8	2.7	2.2	2.5
Pierpont Securities	0.9	3.9	1.6 H	1.0	1.0	1.2	1.5	2.5 H	3.9 H	4.6 H	5.9 H	6.1 H	7.2 H	6.2 H	6.6 H	83.0	4.0 H	2.8	3.8 H
Nat'l Assn. of Realtors	0.5	3.5	0.7	0.5	0.6	0.7	0.9	1.4	2.5	3.2	4.1	4.9	6.0	4.8	4.7	na	3.2	2.4	3.0
Kellner Economic Advisers	0.5	3.5	0.6	0.6	0.6	0.6	0.8	0.9	1.8	2.6	3.6	4.4	5.5	5.0	4.5	85.0 H	3.0	2.9	3.0
Cycledata Corp.	0.5	3.3 L	0.7	0.5	0.4	0.5	0.7	1.0	1.8	2.9	4.0	4.8	6.1	4.5	4.4	73.0	2.2	2.4	2.7
Thredgold Economics	0.4	3.5	0.7	0.5	0.4	0.5	0.6	0.9	1.2	2.2	3.1	3.7	4.9	3.9	4.1	74.0	3.2	2.1	2.4
UBS	0.3	na	0.8	na	0.6	na	na	1.0	1.8	2.8	3.9	na	na	na	na	na	2.6	2.0	3.7
Russell Investments	0.3	3.3 L	0.5	0.3	0.3	0.4	0.6	1.0	1.9	2.8	3.7	4.4	5.4	4.5	4.4	75.0	2.4	2.4	2.2
RidgeWorth Investments	0.3	3.5	0.5	0.5	0.3	0.4	0.5	0.6	1.4	2.6	3.7	4.0	4.9	2.9 L	4.3	74.0	3.5	2.2	2.2
SunTrust Banks	0.3	3.3 L	0.8	0.6	0.1	0.3	0.5	0.6	1.0	1.7 L	2.1 L	3.8	4.7	4.4	3.4 L	80.3	3.5	1.9	2.4
Action Economics	0.3	3.3 L	0.8	0.3	0.5	0.9	1.2	1.5	2.3	3.0	4.0	3.9	5.3	3.7	3.9	73.5	3.0	2.2	3.3
Moody's Capital Markets Group	0.3	3.3 L	0.5	0.3	0.2	0.3	0.5	0.7	1.3	2.4	3.4	4.1	5.2	4.1	4.1	75.8	3.1	2.0	1.9
Naroff Economic Advisors	0.3	3.3 L	0.5	0.3	0.4	0.4	0.5	0.8	1.8	2.9	4.0	5.0	6.1	4.7	4.7	68.5 L	3.1	2.5	2.6
Stone Harbor Investment Partners	0.3	3.3 L	0.5	0.5	0.3	0.5	0.7	1.0	1.9	3.1	4.1	4.8	5.6	na	4.5	71.0	3.1	2.3	2.2
Swiss Re	0.3	3.3 L	0.3	0.2	0.1	0.2	0.3	0.8	1.7	2.5	3.4	4.3	5.0	na	4.4	na	2.9	1.6	1.8
Scotiabank Group	0.3	3.3 L	na	na	0.2	na	na	0.9	2.0	3.3	4.2	na	na	na	na	na	2.5	1.8	2.1
DePrince & Associates	0.2	3.3 L	0.6	0.4	0.2	0.4	0.6	0.9	1.5	2.7	3.7	4.5	5.4	3.7	4.6	74.6	3.1	1.9	2.2
Wells Fargo	0.2	3.3 L	0.4	0.2	0.3	0.4	0.5	0.7	1.2	2.3	3.4	4.2	5.4	4.0	4.1	76.7	2.1 L	2.2	2.1
Fannie Mae	0.2	3.3 L	na	na	0.3	na	0.2	na	na	2.3	3.4	na	na	na	4.2	na	2.4	1.9	2.1
Moody's Analytics	0.2	3.3 L	0.7	0.5	0.3	0.4	0.5	0.9	2.9	3.9	4.7	5.1	6.4	na	5.8	na	4.0 H	2.1	2.5
AIG	0.2	3.3 L	na	na	0.1	0.1	0.2	0.3 L	0.9	2.9	3.9	4.2	5.4	na	4.5	74.8	3.2	0.9 L	1.7
MacroFin Analytics	0.2	3.3 L	0.6	0.2	0.2	0.2	0.6	0.6	1.4	2.3	3.4	4.3	5.5	4.4	4.3	74.8	2.8	1.3	1.5 L
Mesirow Financial	0.2	3.3 L	0.4	0.2	0.4	0.4	0.6	1.0	1.9	3.3	4.3	5.1	6.0	4.7	5.0	72.8	2.9	1.4	2.0
ClearView Economics	0.2	3.3 L	0.4	0.1 L	0.1	0.2	0.2	0.3 L	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	75.7	3.5	2.5	2.9
Nomura Securities, Inc.	0.2	3.3 L	0.6	0.2	0.1	0.1	0.2	0.5	1.3	2.3	3.4	4.0	5.4	na	4.0	75.0	2.5	1.9	2.5
JPMorgan Private Banking	0.2	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	0.9	2.1	3.1	4.0	5.2	4.0	3.9	73.0	2.3	1.9	2.3
Woodworth Holdings	0.2	3.3 L	0.5	0.1 L	0.1	0.2	0.3	0.5	1.3	2.4	3.5	4.2	5.5	4.2	4.2	77.0	3.0	1.5	1.5 L
RBS Securities	0.2	3.3 L	0.4	0.2	0.1	0.2	0.3	0.4	1.0	2.0	3.0	3.1 L	4.0 L	3.8	3.6	74.0	2.6	2.2	2.0
Chmura Economics & Analytics	0.2	3.3 L	0.4	0.2	0.1	0.2	0.2	0.5	1.3	2.5	3.5	4.3	na	na	4.2	71.9	3.7	2.4	2.4
Economist Intelligence Unit	0.1 L	3.3 L	0.6	0.2	0.2	0.2	0.2	0.8	1.5	2.6	4.0	na	na	na	4.7	na	2.8	na	2.3
RBC Capital Markets	0.1 L	3.3 L	0.5	na	0.1	0.1 L	0.3	0.6	1.4	2.8	4.1	na	na	na	na	na	na	na	na
Loomis, Sayles & Company	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.2	0.3 L	1.4	2.5	3.5	4.2	5.2	3.8	4.1	74.9	3.0	1.6	2.1
Oxford Economics	0.1 L	3.3 L	0.4	na	0.0 L	0.1 L	0.3	0.7	1.5	2.6	4.0	na	na	na	4.4	76.1	2.8	2.0	2.0
BMO Capital Markets	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.5	0.8	1.7	3.1	4.0	4.6	5.6	4.1	5.3	73.4	3.1	1.9	2.2
GLC Financial Economics	0.1 L	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	1.0	2.1	3.3	4.1	5.3	3.9	4.3	73.0	2.1 L	2.4	2.5
Wells Capital Management	0.1 L	na	0.6	0.3	0.2	0.3	0.5	0.6	1.1	2.9	3.7	4.2	4.9	4.5	4.8	75.1	3.2	2.3	2.7
Comerica Bank	0.1 L	3.3 L	0.7	na	0.1	0.2	0.2	0.4	1.4	2.7	3.9	na	na	na	4.9	na	2.7	2.1	1.9
Wintrust Wealth Management	0.1 L	3.3 L	0.7	0.2	0.1	0.2	0.3	0.5	1.1	2.3	3.3	4.2	5.3	4.1	4.2	74.6	2.4	2.0	2.2
Daiwa Capital Markets America	0.1 L	3.3 L	0.5	0.2	0.2	0.2	0.3	0.9	1.4	2.4	3.5	4.2	5.4	4.2	4.2	77.0	3.5	2.0	2.2
RDQ Economics	0.1 L	3.3 L	0.4	0.2	0.1	0.3	0.7	1.1	2.4	3.7	4.9	5.2	6.4	5.2	5.4	74.2	3.3	3.1 H	3.5
Goldman Sachs & Co.	0.1 L	3.3 L	0.3 L	na	0.0 L	na	na	0.7	1.6	2.9	3.7	3.8	na	na	4.4	na	2.5	1.5	1.9
Georgia State University	0.1 L	3.3 L	na	na	0.0 L	0.1 L	0.1 L	0.4	1.5	2.8	3.7	4.4	5.5	na	4.3	na	2.5	1.7	1.6
Societe Generale	0.1 L	3.3 L	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.1	2.3	3.3	4.0	4.9	na	na	na	2.2	2.0	1.8
Standard & Poor's Corp.	0.1 L	3.3 L	0.4	0.3	0.1	0.1 L	0.2	0.4	1.5	2.8	na	4.5	5.6	4.3	4.6	na	2.7	1.7	2.3
June Consensus	**0.3**	**3.3**	**0.6**	**0.3**	**0.3**	**0.4**	**0.5**	**0.8**	**1.6**	**2.7**	**3.7**	**4.4**	**5.5**	**4.3**	**4.5**	**74.8**	**2.9**	**2.1**	**2.4**
Top 10 Avg.	0.6	3.6	1.0	0.7	0.7	0.8	1.0	1.4	2.5	3.4	4.4	5.1	6.2	4.9	5.2	78.2	3.5	2.6	3.2
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.1	0.1	0.2	0.4	1.0	2.1	3.1	3.8	4.9	3.7	3.9	71.9	2.3	1.5	1.8
May Consensus	0.3	3.3	0.6	0.4	0.3	0.4	0.5	0.8	1.7	2.9	3.9	4.5	5.7	4.4	4.5	73.4	2.9	2.1	2.4
Number of Forecasts Changed From A Month Ago:																			
Down	4	3	9	7	8	5	9	11	23	27	29	21	18	14	23	5	12	8	11
Same	34	38	25	22	30	27	25	25	19	14	14	11	13	10	12	11	21	25	26
Up	7	1	7	7	7	8	7	8	2	4	1	6	5	4	6	15	11	10	7
Diffusion Index	53 %	48 %	48 %	50 %	49 %	54 %	48 %	47 %	26 %	24 %	18 %	30 %	32 %	32 %	29 %	66 %	49 %	52 %	45 %

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Fed's Major Currency $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	2.05	2.60	3.00	na	na	na
Moody's Analytics	0.48	0.46	0.48	2.40	2.82	3.45	na	na	na
Nomura Securities	na	na	na	na	na	na	na	na	na
Barclays	0.35	0.35	na	2.00	2.00	na	na	na	na
BMO Capital Markets	0.45	0.40	0.35	1.90	2.30	2.80	73.50	74.30	73.90
Mizuho Research Institute	0.46	0.43	0.40	1.90	2.00	1.90	77.3	78.7	79.9
UBS	na	na	na	2.20	2.40	2.85	na	na	na
Wells Fargo	0.45	0.45	0.40	1.90	2.00	2.20	na	na	na
ING Financial Markets	0.40	0.40	0.40	1.80	1.90	1.90	75.7	74.3	72.7
Moody's Capital Markets	na	na	na	2.05	2.20	2.35	73.2	73.3	73.8
June Consensus	**0.43**	**0.42**	**0.41**	**2.02**	**2.25**	**2.56**	**74.9**	**75.1**	**75.1**
High	0.48	0.46	0.48	2.40	2.82	3.45	77.3	78.7	79.9
Low	0.35	0.35	0.35	1.80	1.90	1.90	73.2	73.3	72.7
Last Months Avg.	0.42	0.41	0.42	2.10	2.18	2.49	75.6	75.3	74.5

Japan

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Yen/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	1.14	1.15	1.19	82.8	83.6	85.4
Nomura Securities	na	na	na	1.30	1.25	1.40	na	na	na
BMO Capital Markets	0.20	0.20	0.20	0.95	1.00	1.10	82.0	84.0	89.0
Mizuho Research Institute	0.33	0.33	0.33	0.95	1.00	0.95	77.0	80.0	79.0
Barclays	0.20	0.20	na	1.12	1.03	na	88.0	90.0	90.0
UBS	na	na	na	0.90	1.10	1.30	na	85.0	na
Wells Fargo	0.20	0.20	0.20	0.96	1.00	1.02	na	na	na
ING Financial Markets	0.20	0.20	0.20	0.85	0.90	1.20	82.0	85.0	90.0
Moody's Capital Markets	na	na	na	0.95	1.00	1.05	83.0	84.0	85.0
June Consensus	**0.23**	**0.23**	**0.23**	**1.01**	**1.05**	**1.15**	**82.5**	**84.5**	**86.4**
High	0.33	0.33	0.33	1.30	1.25	1.40	88.0	90.0	90.0
Low	0.20	0.20	0.20	0.85	0.90	0.95	77.0	80.0	79.0
Last Months Avg.	0.23	0.23	0.23	1.08	1.12	1.22	82.0	83.3	84.8

United Kingdom

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gilt Yields %			USD/Pound Sterling		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	1.61	1.62	1.65
Moody's Analytics	na	na	na	2.45	2.57	2.88	1.58	1.58	1.59
Nomura Securities	na	na	na	2.30	2.35	2.55	na	na	na
BMO Capital Markets	1.00	0.90	0.75	2.00	2.40	2.95	1.59	1.57	1.60
Mizuho Research Institute	1.00	0.90	0.80	1.95	2.10	2.10	na	na	na
Barclays	0.95	0.95	na	2.83	3.03	na	1.55	1.52	1.50
UBS	na	0.80	na	2.60	2.65	3.00	na	1.44	na
Wells Fargo	0.75	0.65	0.65	2.00	2.20	2.50	na	na	na
ING Financial Markets	0.65	0.65	0.65	1.90	2.10	2.40	1.53	1.53	1.56
Moody's Capital Markets	na	na	na	2.05	2.10	2.35	1.58	1.57	1.55
June Consensus	**0.87**	**0.81**	**0.71**	**2.23**	**2.39**	**2.59**	**1.57**	**1.55**	**1.58**
High	1.00	0.95	0.80	2.83	3.03	3.00	1.61	1.62	1.65
Low	0.65	0.65	0.65	1.90	2.10	2.10	1.53	1.44	1.50
Last Months Avg.	0.87	0.77	0.70	2.31	2.39	2.56	1.56	1.58	1.60

Switzerland

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			CHF/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	0.97	0.98	1.00
Moody's Analytics	na	na	na	1.30	1.40	1.59	0.82	0.86	0.90
Nomura Securities	na	na	na	na	na	na	na	na	na
BMO Capital Markets	na	na	na	na	na	na	0.93	0.96	0.99
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Barclays	na	na	na	na	na	na	0.96	1.04	1.08
UBS	na	0.12	na	1.25	1.25	1.70	na	1.04	na
Wells Fargo	na	na	na	na	na	na	na	na	na
ING Financial Markets	0.10	0.08	0.10	0.80	0.90	1.00	1.04	1.04	1.00
Moody's Capital Markets	na	na	na	0.80	0.85	1.00	0.90	0.90	0.92
June Consensus	**0.10**	**0.10**	**0.10**	**1.04**	**1.10**	**1.32**	**0.94**	**0.97**	**0.98**
High	0.10	0.12	0.10	1.30	1.40	1.70	1.04	1.04	1.08
Low	0.10	0.08	0.10	0.80	0.85	1.00	0.82	0.86	0.90
Last Months Avg.	0.10	0.80	0.10	1.00	1.08	1.30	0.94	0.95	0.96

Canada

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			CAD/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	2.00	2.40	2.85	1.00	0.99	0.97
Moody's Analytics	na	na	na	2.04	1.81	1.73	1.00	1.00	1.02
Nomura Securities	na	na	na	2.30	2.40	2.75	na	na	na
BMO Capital Markets	1.25	1.25	1.75	2.10	2.45	3.00	1.01	1.01	0.99
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Barclays	na	na	na	na	na	na	0.98	0.96	0.95
UBS	na	na	na	2.45	2.50	2.85	na	1.05	na
Wells Fargo	1.15	1.20	1.75	2.30	2.70	3.20	na	na	na
ING Financial Markets	1.50	1.60	2.10	1.90	2.10	2.40	1.02	1.01	1.00
Moody's Capital Markets	na	na	na	2.05	2.20	2.35	1.00	1.00	1.02
June Consensus	**1.30**	**1.35**	**1.87**	**2.14**	**2.32**	**2.64**	**1.00**	**1.00**	**0.99**
High	1.50	1.60	2.10	2.45	2.70	3.20	1.02	1.05	1.02
Low	1.15	1.20	1.75	1.90	1.81	1.73	0.98	0.96	0.95
Last Months Avg.	1.25	1.35	1.78	2.21	2.38	2.80	1.00	1.00	1.00

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/AUD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	1.06	1.08	1.09
Moody's Analytics	na	na	na	3.99	4.01	4.30	1.02	1.00	0.97
Nomura Securities	na	na	na	3.85	3.85	4.25	na	na	na
BMO Capital Markets	na	na	na	na	na	na	1.00	1.00	1.05
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Barclays	na	na	na	na	na	na	1.05	1.06	1.07
UBS	na	na	na	3.90	4.10	4.60	na	1.00	na
Wells Fargo	na	na	na	na	na	na	na	na	na
ING Financial Markets	4.50	4.40	4.60	3.00	3.20	3.60	0.93	0.91	0.90
Moody's Capital Markets	na	na	na	3.30	3.35	3.45	1.00	0.99	0.95
June Consensus	**4.50**	**4.40**	**4.60**	**3.61**	**3.70**	**4.04**	**1.01**	**1.01**	**1.01**
High	4.50	4.40	4.60	3.99	4.10	4.60	1.06	1.08	1.09
Low	4.50	4.40	4.60	3.00	3.20	3.45	0.93	0.91	0.90
Last Months Avg.	4.60	4.50	4.50	3.95	4.04	4.32	1.03	1.03	1.02

Eurozone

Blue Chip Forecasters	3 Mo. Interest Rate %			USD/EUR		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	1.28	1.26	1.25
Moody's Analytics	na	na	na	1.30	1.29	1.27
Nomura Securities	na	na	na	na	na	na
BMO Capital Markets	0.65	0.65	0.90	1.30	1.30	1.32
Mizuho Research Institute	0.60	0.50	0.60	1.26	1.24	1.21
Barclays	0.65	0.75	na	1.30	1.25	1.20
UBS	na	na	na	na	1.15	na
Wells Fargo	0.60	0.60	0.90	na	na	na
ING Financial Markets	0.80	0.80	1.15	1.15	1.15	1.20
Moody's Capital Markets	na	na	na	1.28	1.26	1.24
June Consensus	**0.66**	**0.66**	**0.89**	**1.27**	**1.24**	**1.24**
High	0.80	0.80	1.15	1.30	1.30	1.32
Low	0.60	0.50	0.60	1.15	1.15	1.20
Last Months Avg.	0.64	0.65	0.83	1.26	1.26	1.27

	10 Yr. Gov't Bond Yields %											
	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
ING Financial Markets	1.50	1.60	1.80	3.10	3.30	3.30	6.20	6.40	6.40	6.70	6.70	6.60
UBS	2.30	2.40	2.70	3.09	3.19	3.49	5.52	5.62	5.92	na	na	na
Mizuho Research Institute	1.65	1.70	1.75	na	na	na	na	nas	na	na	na	na
BMO Capital Markets	1.65	2.00	2.55	na	na	na	na	na	na	na	na	na
Moody's Capital Markets	1.65	1.70	1.95	2.90	2.95	2.95	5.50	5.25	5.00	5.70	5.35	5.20
Moody's Analytics	2.00	2.00	2.00	3.33	3.55	3.75	5.61	5.41	5.13	5.90	6.10	6.10
June Consensus	**1.79**	**1.90**	**2.13**	**3.11**	**3.25**	**3.37**	**5.71**	**5.67**	**5.61**	**6.10**	**6.05**	**5.97**
High	2.30	2.40	2.70	3.33	3.55	3.75	6.20	6.40	6.40	6.70	6.70	6.60
Low	1.50	1.60	1.75	2.90	2.95	2.95	5.50	5.25	5.00	5.70	5.35	5.20
Last Months Avg.	1.89	1.93	2.08	3.05	3.14	3.30	5.68	5.67	5.48	5.53	5.44	5.39

	Consensus Forecasts 10-year Bond Yields vs U.S. Yield			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.86	-1.01	-1.20	-1.41
United Kingdom	0.00	0.21	0.14	0.04
Switzerland	-1.11	-0.98	-1.15	-1.23
Canada	0.05	0.12	0.07	0.09
Australia	1.41	1.59	1.46	1.48
Germany	-0.38	-0.23	-0.35	-0.43
France	0.78	1.08	1.00	0.82
Italy	4.05	3.69	3.42	3.06
Spain	4.58	4.08	3.80	3.41

	Consensus Forecasts 3 Mo. Deposit Rates vs U.S. Rate			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.36	-0.21	-0.64	-0.17
United Kingdom	0.36	0.44	0.39	0.31
Switzerland	-0.53	-0.33	-0.32	-0.31
Canada	0.90	0.87	0.94	1.46
Australia	3.47	4.07	3.99	4.19
Eurozone	0.02	0.23	0.25	0.48

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

The Europe Link

With the situation in Europe becoming more uncertain and the euro at a 22-month low against the dollar, there is rising concern about the spill-over to the US. Most of the contagion would come from the banking system and financial markets, particularly if the situation deteriorates into a full-blown crisis. There are also linkages through trade flows, which take longer to be realized. In our baseline case where the Eurozone avoids a crisis but falls into a mild recession, US exports to the region will slow. This is mostly due to a decline in demand rather than an adjustment in the exchange rate, as we argue below.

Intuitively, exchange rate changes should cause fluctuations in trade flows. The logic is simple: depreciation of a country's currency will support exports but hurt imports as it becomes more expensive to buy foreign goods. This assumes that changes in exchange rates "pass through" to import prices and in turn business and consumer prices.

This is where the link breaks in practice. Most literature finds incomplete exchange rate pass-through in the US. Recent work by the IMF, BIS and Federal Reserve has found that the pass-through from exchange rates to core import prices has declined from about 50% in the 1970-80s to about 20% during the past decade. The impact will differ depending on how long the change in the exchange is sustained, the magnitude of the decline and the reason for the change. Moreover, the relationship between import prices and trade flows is loose.

Our international economist, Gustavo Reis, has developed a model to determine the impact of changes in the real exchange rate on trade flows (real exchange rate is the price of foreign goods in units of domestic goods). He finds that a 10% depreciation in the real exchange rate would only boost net exports by 3.2pp over the following two quarters. Focusing on the past few quarters, he finds that the real exchange rate only explains 0.2pp of the change in exports. The bulk of export growth is explained by the change in global demand.

The OECD takes it a step further and investigates the impact of exchange rate changes on overall GDP and inflation. Focusing on the euro, a 10% nominal depreciation against the dollar, holding all else equal, would only slice 0.1pp from US GDP over a one year period, provided the exchange rate holds at that level for the year. Assuming it holds for four years, it would cut 0.3pp from baseline growth.

The above simulation controls for magnitude and duration of the change in exchange rates, but it does not account for the reason behind the move. This is a crucial part of the story. If the real exchange rate is altered because of an external shock to the global economy, any impact the exchange rate would have on trade flows will be marginalized. A negative shock will cut income and therefore reduce aggregate demand, shrinking all trade flows. The income effect overwhelms the price/exchange rate effect.

The Lehman bankruptcy and financial crisis in the fall of 2008 is the perfect example of such a shock. It caused large swings in exchange rates, but more importantly, it stifled economic growth. The sharp decline in global demand dwarfed all else, causing trade activity to collapse across the world. From mid- 2008 through mid-2009, world trade fell by 20%. As a percent of GDP, global trade declined nearly 30% during the recession. This caused a rebalancing in the global economy – deficits were reduced and surpluses shrank.

In addition to the dramatic loss of income and demand, the crisis created a freezing of the credit markets. Many firms rely on credit lines, particularly dollar dominated, for international trade. Lenders pulled back dramatically, which disproportionately hurt small firms and the emerging markets. A Federal Reserve Board paper found that domestic-oriented firms that were able to receive domestic trade credit experienced smaller decline in sales than firms that were reliant on external finance.

Laurence Boone, our Chief European Economist, believes that if Greece were to exit the Eurozone with a disorderly default, it would create a crisis akin to the Lehman bankruptcy, which would be sufficient to push the global economy back into recession. The credit markets would likely freeze and demand would collapse, leading to a dramatic decline in trade volumes. Once again, exchange rate differentials would have negligible effects.

The baseline forecast for the Eurozone is that a crisis is avoided and the region falls into a mild recession this year. Under this forecast, the US continues along with its rehab recovery. Without big swings in demand or change in credit availability for external trade financing, exchange rate adjustments could matter more. However, as we argue above, there would need to be a sustained large movement in the Euro/USD for it to matter to the outlook.

Since the problems with Greece surfaced two years ago, the Euro/USD swung around 1.30, with a low of 1.19 reached on June 7, 2010 and a high of 1.49 reached on May 2, 2011. Our FX strategists believe that 1.30 is close to fair value. If the exchange rate falls below this level and holds, it would hurt US export growth. This would lead to modest widening in the trade deficit, partly reversing the sharp narrowing that occurred during the recession.

It is also important, however, to remember that Europe only makes up 18% of US exports, so there could be offsetting factors from other economies. The two other main countries the US exports to are Canada and Mexico

While potential dollar appreciation will only have a modest effect on overall growth, it would disproportionately hurt the manufacturing sector, which is reliant on international trade. Providing some offset would be lower manufacturing costs since US firms rely on foreign equipment and components in producing their goods. A NY Fed paper, which focused on the dollar appreciation in the late 1990s, found that the loss of revenue from dollar appreciation exceeds the cost saving from lower import prices. While output and profits will be affected, there is little evidence that firms will reduce employment in response to exchange rate changes. It does, however, keep downward pressure on wages.

Dollar strength would not, in itself, be a sufficient condition for stopping the "manufacturing renaissance" in the US. We believe this is a secular trend. It would simply create a hiccup in this trend.

For equity investors, it means those corporations that have exposure to the European market and rely on external financing are likely to see the biggest drag. The manufacturing industry is particularly vulnerable. The macro implications, however, are only modest. The US trade deficit, and therefore the current account deficit, will widen, reversing some of the narrowing during the crisis. We expect net exports to slice 0.1pp from growth this year and 0.2pp next year year. In the worst-case scenario where a Greece exit creates a Lehman-sized shock, all bets are off. Trade flows would likely collapse amid weak global demand and tight credit. It would spur further global rebalancing, but it will leave painful scars on the global economy.

Michelle Meyer, Bank of America-Merrill Lynch, New York, NY

The Fiscal Cliff -- Serious, But Not Likely

The Congressional Budget Office recently published its estimates of the approaching fiscal cliff, or the tightening in fiscal policy that will occur in January if Congress does not extend a long list of expiring tax and spending provisions. The estimates are valuable because the CBO has the resources to monitor and assess all the *(continued on next page)*

Viewpoints

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changes that are scheduled to occur. The major items are well known, such as the Bush tax cuts and the automatic spending reductions that fell out of the resolution of the debt-ceiling debate, but a host of other changes also are on tap and a proper reckoning of the fiscal shift should include the long list of lesser known items. (A listing of expiring tax provisions in 2012 published by the Joint Committee on Taxation covers nine pages.)

The headline estimate published by the CBO was striking, as total fiscal tightening would amount to $607 billion, enough to cut the deficit in the current fiscal year by approximately half. This amount, while notable, understates the significance of the approaching changes. The Congressional Budget Office typically calculates its budget figures on a fiscal-year basis (October to September). Because most of the tax increases and spending cuts begin in January, they affect only three-quarters of the next fiscal year. Thus, the estimated budget effect would be even larger if the changes were in place for an entire fiscal year (more than $800 billion or two-thirds of the likely deficit in the current fiscal year).

These effects represent the first round influences on the budget deficit. The fiscal tightening would undoubtedly slow economic activity, and the slowing in the rate of economic growth would trigger various automatic stabilizers. That is, with lower incomes, many individuals would see their tax burdens reduced, and some individuals would begin receiving income-support payments. These shifts would reverse some of the effect of the scheduled adjustments and leave net fiscal tightening of $560 billion ($743 billion when quoted at an annual rate).

Back-of-the-envelope calculations suggest that the economic impact of the fiscal tightening would be profound. The annualized net effect of fiscal tightening represents almost five percent of our estimate of nominal GDP at the end of this year. With a multiplier of 1.0 to 1.5 and a likely inflation rate of two percent, the fiscal shift would shave approximately four percentage points from GDP growth. Our current forecast for GDP next year, which assumes no fiscal tightening, totals 3.25 percent. Thus, if the fiscal tightening occurs, the economy will most likely contract next year.

The CBO also provided an estimate of GDP growth, and its view was less dire than ours, showing Q4-over-Q4 growth of 0.5 percent (a drop of 1.3 percent in the first half and growth of 2.3 percent in the second half). However, the CBO has an optimistic view on growth in the absence of fiscal tightening (4.4 percent). That view seems ambitious in light of recent developments suggesting moderate growth.

The effects of the fiscal cliff on the economy would be pronounced, but we do not expect Congress to allow the tightening to occur. Legislators seem to understand that the changes would tip the economy into recession, and they are not likely to risk such an outcome at this time. In addition, the experience in Europe and the shift in sentiment away from austerity in this region will probably lead most representatives and senators to believe that fiscal tightening should be delayed.

The timing of the election cycle is also likely to lead Congress to extend most or all of the expiring tax and spending provisions. Legislators will probably not address these issues before the election, and they will not have sufficient time after the balloting to debate the issues fully. The easiest course will be to extend the provisions and allow the new Congress to consider matters carefully. In addition, many will probably believe that a lame-duck Congress should not be making such weighty decisions on tax and spending policy. We look for little or no fiscal tightening in early 2013, but we hope the new Congress will begin meaningful debate on long-term deficit reduction.

Michael Moran, Daiwa Capital Markets America, New York, NY

Grexit?

It's been three weeks since the Greek elections produced a stalemate between pro- and anti-bailout parties, unleashing a wave of doubts about Greece's future in the euro, and about the common currency itself. In that short span, the euro has dropped by more than 4% to US$1.251, 10-year Treasury yields have hit century-lows of 1.7%, and global equity markets have dropped almost 5%. The market cap of the MSCI World index has shed more than US$2 trillion in value in those three weeks, taking the index almost all the way back to where it started 2012. Global stocks are also now almost back to where they stood in November 2009, when Greece's deep debt woes first came fully to the light of day. Putting the market cap loss of more than $2 trillion into some perspective, the value of Greece's nominal GDP was US$265 billion (and falling) over the past four quarters, or roughly three Facebooks. True, this comparison mixes stocks (equity values) and flows (GDP), but it gives a sense of just how much havoc a grand total of 0.16% of the world's population can cause for financial markets.

Global equities actually had a small reprieve this week, in no small part due to a steady drumbeat of decent U.S. economic data, particularly on the housing front. New and existing home sales both provided more compelling evidence that the U.S. market has finally turned the corner, while a trio of measures suggested that home prices are following. But that news played a secondary role against the much greater drama unfolding in Europe. Markets were somewhat calmed by official comments of support for Greece, but also keenly aware of the fact that preparations for a Greek exit are intensifying across the continent. As Ben points out, it certainly is not just Greece that is roiling European markets, with deepening concerns about Spain, its banks, and its regional finances, as well as underlying softness in the broader European economy. While last week's Q1 GDP report suggested that the Eurozone had just managed to skirt a technical recession, a deep drop in May PMIs leave little doubt that the region is in fact in a very real recession. While that's bad enough, the really bad news for markets is that the next Greek elections are still another three weeks away.

Douglas Porter, BMO Capital Markets, Toronto, Canada

U.S. Manufacturing Shows More Signs Of A Slowdown

While the U.S. manufacturing expansion does not look to be in any near-term danger of reversing, there was more data this week to support the view that U.S. manufacturing momentum is decelerating. An economic recession in much of Europe and slower growth in many emerging market economies such as China, India and Brazil is starting to take a toll on the U.S. manufacturing expansion as well. The week started on a sour note with the release of the Richmond Fed manufacturing PMI for May, which came in weaker than expected at 4, down from a 14 reading in April.

This view of a slower manufacturing expansion was corroborated by the first release of the Markit manufacturing PMI for the United States, which also fell to 53.9 from 56.0 in April. This index is the first national read on U.S. manufacturing for May, and according to Markit, is based on about 85 percent of the usual monthly replies to the ISM PMI released later in the month. While we do not yet have a lot of history to go on with this manufacturing index, it may become a closely watched first take on manufacturing activity in the months ahead. The PMI was pulled down by deterioration in output, new orders, employment, and slower inventory growth. The April durable goods orders also showed broad-based weakness in machinery, fabricated metals, and computer orders that suggests less durable goods manufacturing and business equipment spending in the months ahead.

Wells Fargo Securities, Charlotte, NC

Long-Range Forecasts:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2014 through 2018 and averages for the five-year periods 2014-2018 and 2019-2023. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		----------Average For The Year----------					Five-Year Averages	
Interest Rates		**2014**	**2015**	**2016**	**2017**	**2018**	**2014-2018**	**2019-2023**
1. Federal Funds Rate	**CONSENSUS**	**0.7**	**1.9**	**2.9**	**3.3**	**3.5**	**2.5**	**3.6**
	Top 10 Average	1.3	2.9	3.8	4.3	4.4	3.3	4.4
	Bottom 10 Average	0.2	1.0	1.7	2.1	2.4	1.5	2.6
2. Prime Rate	**CONSENSUS**	**3.8**	**4.8**	**6.0**	**6.4**	**6.6**	**5.5**	**6.6**
	Top 10 Average	4.4	5.9	6.9	7.3	7.4	6.3	7.4
	Bottom 10 Average	3.3	4.0	4.9	5.3	5.5	4.6	5.6
3. LIBOR, 3-Mo.	**CONSENSUS**	**1.1**	**2.4**	**3.3**	**3.7**	**3.8**	**2.9**	**3.9**
	Top 10 Average	1.7	3.4	4.2	4.6	4.6	3.7	4.6
	Bottom 10 Average	0.6	1.6	2.2	2.7	2.8	2.0	3.0
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**0.9**	**2.1**	**3.0**	**3.4**	**3.5**	**2.6**	**3.6**
	Top 10 Average	1.4	2.9	3.8	4.3	4.4	3.3	4.3
	Bottom 10 Average	0.4	1.4	2.0	2.3	2.6	1.7	2.7
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**0.7**	**1.8**	**2.8**	**3.3**	**3.4**	**2.4**	**3.5**
	Top 10 Average	1.3	2.7	3.7	4.2	4.3	3.2	4.2
	Bottom 10 Average	0.2	1.1	1.8	2.2	2.4	1.5	2.6
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**0.8**	**2.0**	**3.0**	**3.4**	**3.6**	**2.6**	**3.6**
	Top 10 Average	1.5	2.9	3.9	4.3	4.4	3.4	4.4
	Bottom 10 Average	0.3	1.3	1.9	2.3	2.5	1.7	2.7
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**1.1**	**2.2**	**3.2**	**3.6**	**3.7**	**2.8**	**3.8**
	Top 10 Average	1.7	3.2	4.1	4.5	4.7	3.6	4.6
	Bottom 10 Average	0.5	1.5	2.1	2.5	2.6	1.8	2.7
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**1.4**	**2.6**	**3.4**	**3.8**	**4.0**	**3.0**	**4.0**
	Top 10 Average	2.1	3.4	4.4	4.7	5.0	3.9	5.0
	Bottom 10 Average	0.8	1.8	2.4	2.7	2.8	2.1	3.0
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**2.3**	**3.2**	**3.9**	**4.2**	**4.4**	**3.6**	**4.4**
	Top 10 Average	3.1	4.3	4.9	5.1	5.3	4.5	5.4
	Bottom 10 Average	1.6	2.3	2.9	3.1	3.2	2.6	3.3
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.3**	**4.1**	**4.5**	**4.7**	**4.8**	**4.3**	**4.9**
	Top 10 Average	4.1	4.9	5.3	5.6	5.7	5.1	5.8
	Bottom 10 Average	2.7	3.3	3.6	3.7	3.9	3.4	3.9
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**4.2**	**4.9**	**5.3**	**5.5**	**5.5**	**5.1**	**5.5**
	Top 10 Average	5.0	5.7	6.2	6.4	6.5	6.0	6.6
	Bottom 10 Average	3.5	4.1	4.5	4.4	4.5	4.2	4.4
13. Corporate Aaa Bond Yield	**CONSENSUS**	**4.9**	**5.6**	**6.0**	**6.2**	**6.2**	**5.8**	**6.2**
	Top 10 Average	5.7	6.2	6.6	7.1	7.1	6.5	7.2
	Bottom 10 Average	4.2	5.0	5.3	5.3	5.3	5.0	5.2
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.6**	**7.0**	**7.2**	**7.3**	**6.8**	**7.2**
	Top 10 Average	6.7	7.2	7.6	8.1	8.1	7.5	8.2
	Bottom 10 Average	5.4	6.1	6.4	6.4	6.5	6.1	6.3
14. State & Local Bonds Yield	**CONSENSUS**	**4.5**	**5.1**	**5.4**	**5.6**	**5.6**	**5.2**	**5.5**
	Top 10 Average	5.1	5.7	6.0	6.2	6.4	5.9	6.3
	Bottom 10 Average	3.9	4.5	4.8	4.9	4.9	4.6	4.8
15. Home Mortgage Rate	**CONSENSUS**	**5.1**	**5.8**	**6.2**	**6.4**	**6.5**	**6.0**	**6.5**
	Top 10 Average	5.9	6.6	7.0	7.3	7.3	6.8	7.3
	Bottom 10 Average	4.4	5.1	5.5	5.6	5.7	5.3	5.7
A. FRB - Major Currency Index	**CONSENSUS**	**75.5**	**76.2**	**77.2**	**77.3**	**77.5**	**76.8**	**77.1**
	Top 10 Average	78.1	79.4	81.8	82.4	82.8	80.9	82.8
	Bottom 10 Average	72.9	73.1	73.1	72.7	72.6	72.9	72.0
		----------Year-Over-Year, % Change----------					Five-Year Averages	
		2014	**2015**	**2016**	**2017**	**2018**	**2014-2018**	**2019-2023**
B. Real GDP	**CONSENSUS**	**2.9**	**3.0**	**2.9**	**2.8**	**2.7**	**2.8**	**2.5**
	Top 10 Average	3.4	3.4	3.3	3.1	3.1	3.3	2.8
	Bottom 10 Average	2.3	2.5	2.5	2.4	2.3	2.4	2.3
C. GDP Chained Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**
	Top 10 Average	2.5	2.7	2.6	2.5	2.6	2.6	2.5
	Bottom 10 Average	1.7	1.9	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**
	Top 10 Average	2.9	3.0	2.9	2.9	2.9	2.9	2.8
	Bottom 10 Average	2.0	2.0	2.0	1.9	2.0	2.0	2.0

Databank:

2012 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.6	1.0	0.7	0.1								
Auto & Light Truck Sales (b)	14.13	15.04	14.32	14.37								
Personal Income (a, current $)	0.3	0.3	0.4									
Personal Consumption (a, current $)	0.5	0.9	0.3									
Consumer Credit (e)	8.4	4.4	10.2									
Consumer Sentiment (U. of Mich.)	75.0	75.3	76.2	76.4	79.3							
Household Employment (c)	847	428	-31	-169								
Non-farm Payroll Employment (c)	275	259	154	115								
Unemployment Rate (%)	8.3	8.3	8.2	8.1								
Average Hourly Earnings (All, cur. $)	23.28	23.33	23.37	23.38								
Average Workweek (All, hrs.)	34.5	34.6	34.5	34.5								
Industrial Production (d)	4.3	5.0	3.5	5.2								
Capacity Utilization (%)	78.7	78.9	78.4	79.2								
ISM Manufacturing Index (g)	54.1	52.4	53.4	54.8								
ISM Non-Manufacturing Index (g)	56.8	57.3	56.0	53.5								
Housing Starts (b)	0.720	0.718	0.699	0.717								
Housing Permits (b)	0.684	0.707	0.769	0.715								
New Home Sales (1-family, c)	339	358	332	343								
Construction Expenditures (a)	-0.7	-1.4	0.1									
Consumer Price Index (nsa., d)	2.9	2.9	2.7	2.3								
CPI ex. Food and Energy (nsa., d)	2.3	2.2	2.3	2.3								
Producer Price Index (n.s.a., d)	4.1	3.3	2.8	1.9								
Durable Goods Orders (a)	-4.9	2.0	-3.9	0.2								
Leading Economic Indicators (g)	0.1	0.7	0.3	-0.1								
Balance of Trade & Services (f)	-52.5	-45.4	-51.8									
Federal Funds Rate (%)	0.08	0.10	0.13	0.14								
3-Mo. Treasury Bill Rate (%)	0.03	0.09	0.08	0.08								
10-Year Treasury Note Yield (%)	1.97	1.97	2.17	2.05								

2011 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.8	0.9	0.8	0.4	0.0	0.5	0.4	0.2	1.2	0.9	0.5	0.0
Auto & Light Truck Sales (b)	12.64	13.24	13.02	13.13	11.68	11.51	12.20	12.09	13.05	13.22	13.60	13.50
Personal Income (a, current $)	1.1	0.5	0.5	0.4	0.3	0.1	0.1	0.1	0.3	0.4	0.1	0.4
Personal Consumption (a, current $)	0.4	0.8	0.6	0.3	0.2	-0.2	0.8	0.1	0.7	0.2	0.0	0.2
Consumer Credit (e)	2.2	3.2	2.2	2.8	3.0	5.6	5.8	-4.7	3.7	3.3	9.8	7.9
Consumer Sentiment (U. of Mich.)	74.2	77.5	67.5	69.8	74.3	71.5	63.7	55.7	59.4	60.9	64.1	69.9
Household Employment (c)	110	221	213	-136	180	-423	65	304	353	190	317	176
Non-Farm Payroll Employment (c)	110	220	246	251	54	84	96	85	202	112	157	223
Unemployment Rate (%)	9.1	9.0	8.9	9.0	9.0	9.1	9.1	9.1	9.0	8.9	8.7	8.5
Average Hourly Earnings (All, cur. $)	22.86	22.88	22.92	22.97	23.02	23.05	23.13	23.12	23.16	23.12	23.23	23.25
Average Workweek (All, hrs.)	34.3	34.3	34.3	34.4	34.4	34.4	34.4	34.3	34.4	34.4	34.4	34.5
Industrial Production (d)	5.8	5.1	5.4	4.4	3.1	3.2	3.3	3.4	3.3	4.2	4.1	3.8
Capacity Utilization (%)	76.1	75.9	76.5	76.1	76.3	76.3	77.0	77.1	77.2	77.6	77.7	78.3
ISM Manufacturing Index (g)	59.9	59.8	59.7	59.7	54.2	55.8	51.4	52.5	52.5	51.8	52.6	53.1
ISM Non-Manufacturing Index (g)	58.3	59.0	56.3	54.4	54.5	53.3	53.4	53.8	52.6	52.6	52.6	53.0
Housing Starts (b)	0.632	0.518	0.600	0.552	0.551	0.615	0.614	0.581	0.647	0.630	0.708	0.697
Housing Permits (b)	0.566	0.536	0.590	0.578	0.624	0.633	0.627	0.645	0.616	0.667	0.709	0.701
New Home Sales (1-family, c)	308	273	301	312	308	304	297	292	306	314	327	339
Construction Expenditures (a)	-1.4	-1.0	-0.2	0.7	2.5	1.6	-3.3	2.2	1.1	0.3	1.9	1.1
Consumer Price Index (s.a., d)	1.6	2.1	2.7	3.2	3.6	3.6	3.6	3.8	3.9	3.5	3.4	3.0
CPI ex. Food and Energy (s.a., d)	1.0	1.1	1.2	1.3	1.5	1.6	1.7	2.0	2.0	2.1	2.2	2.2
Producer Price Index (n.s.a., d)	3.6	5.4	5.6	6.6	7.1	6.9	7.1	6.6	7.0	5.8	5.6	4.7
Durable Goods Orders (a)	4.0	-1.1	4.6	-2.5	2.0	-1.2	4.2	0.1	-1.4	0.1	4.2	3.3
Leading Economic Indicators (g)	0.2	0.9	1.1	0.0	0.5	0.0	0.2	-0.7	-0.5	0.6	0.3	0.4
Balance of Trade & Services (f)	-47.5	-45.4	-46.1	-43.2	-50.2	-51.8	-45.6	-45.1	-44.0	-43.1	-47.5	-50.4
Federal Funds Rate (%)	0.17	0.16	0.14	0.10	0.09	0.09	0.07	0.10	0.08	0.07	0.08	0.07
3-Mo. Treasury Bill Rate (%)	0.15	0.13	0.10	0.06	0.04	0.04	0.04	0.02	0.01	0.02	0.01	0.01
10-Year Treasury Note Yield (%)	3.39	3.58	3.41	3.46	3.17	3.00	3.00	2.30	1.98	2.15	2.01	1.98

(a) month-over-month % change; (b) millions, saar; (c) thousands, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
May 28 **Memorial Day** **U.S. Markets Closed**	**29** Chicago FRB Midwest Mfg. Index (Apr) S&P Case-Shiller Home Price Index ((Mar) Consumer Confidence (May, Conference Board) ABC Consumer Comfort Index Weekly Store Sales	**30** ADP National Employment Report (May) Pending Home Sales (Apr) EIA Crude Oil Stocks Mortgage Applications	**31** Gross Domestic Product (Q1, Second Estimate) Corporate Profits (Q1, Preliminary) ISM Chicago (May) ISM New York (May) Chain Store Sales (May) Job-Cut Announcements (May) Weekly Jobless Claims Weekly Money Supply	**June 1** Employment Report (May) Personal Income & Consumption (Apr) ISM Manufacturing (May) Motor Vehicle Sales (May) Construction Spending (Apr)
4 Factory Orders (Apr)	**5** ISM Non-Manufacturing (May) ABC Consumer Comfort Index Weekly Store Sales	**6** Productivity (Q1, Revised) Beige Book Mortgage Applications EIA Crude Oil Stocks	**7** Consumer Credit (Apr) Flow of Funds Accounts (Q1) Weekly Jobless Claims Weekly Money Supply	**8** International Trade (Apr) Wholesale Trade (Apr)
11	**12** Federal Budget (May) Import/Export Prices (May) Manpower Employment survey (Q3) Weekly Store Sales ABC Consumer Comfort Index	**13** Retail Sales (May) Business Inventories (Apr) Producer Price Index (May) EIA Crude Oil Stocks Mortgage Applications	**14** Consumer Price Index (May) Current Account (Q1) Weekly Jobless Claims Weekly Money Supply	**15** Industrial Production (May) NY FRB Manufacturing Survey (Jun) Consumer Sentiment (Jun, preliminary, University of Michigan) Treasury International Capital Data (Apr)
18 Housing Market Index (Jun)	**19** **FOMC Meeting** Housing Starts (May) Weekly Store Sales ABC Consumer Comfort Index	**20** **FOMC Meeting** EIA Crude Oil Stocks Mortgage Applications	**21** Existing Home Sales (May) Leading Economic Indicators (May) Philadelphia Fed Survey (Jun) Weekly Jobless Claims Weekly Money Supply	**22**
25 New Home Sales (May) Chicago Fed National Activity Index (May)	**26** Consumer Confidence (Jun, Conference Board) S&P Case-Shiller Home Price Index (Apr) ABC Consumer Comfort Index Weekly Store Sales	**27** Durable Goods Orders (May) Pending Home Sales (May) Chicago Fed Midwest Manufacturing Index (May) EIA Crude Oil Stocks Mortgage Applications	**28** Gross Domestic Product (Q1, final estimate) Corporate Profits (Q1, revised) Agricultural Prices (Mid-Jun) Weekly Jobless Claims Weekly Money Supply	**29** Personal Income and Consumption (May) ISM-Chicago (Jun) ISM-New York (Jun) Consumer Sentiment (Jun, Final, University of Michigan)
July 2 ISM Manufacturing (Jun) Construction Spending (Jun)	**3** Motor Vehicle Sales (Jun) ADP National Employment Report (Jun) Factory Orders (May) ABC Consumer Comfort Index Weekly Store Sales	**4** **Independence Day** **U.S. Markets Closed**	**5** ISM Non-Manufacturing (Jun) Chain Store Sales (Jun) Job-Cut Announcements (Jun) Mortgage Applications EIA Crude Oil Stocks Weekly Jobless Claims Weekly Money Supply	**6** Employment Report (Jun)

BLUE CHIP FORECASTERS

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MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-086 RE: Flotation Costs
Witness: Stephen Gaske

In reference to your testimony at page 15, lines 4-9: Please provide work papers showing the actual flotation costs for each MDU stock issuance during the past 5 years.

Response:

Exhibit No.___(JSG-2), Schedule 3 shows that MDU Resources Group, Inc. ("MDU Resources") has not issued common stock to the public since 2004. However, MDU Resources entered into a sales agency financing agreement dated September 5, 2008 with Wells Fargo Securities, LLC ("Wells Fargo") under which MDU Resources may offer and sell up to 5,000,000 shares of common stock from time to time through Wells Fargo. The sales, if any, will be made in "at-the-market" offerings. MDU Resources will pay Wells Fargo a commission equal to 0.75% of the sales prices of all shares sold and has agreed to reimburse Wells Fargo for its out-of-pocket expenses up to a maximum of $75,000.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-087 RE: MDU's Operating Income and Total Assets
Witness: Stephen Gaske

In reference to your testimony at page 17, lines 13-17: Please provide work papers showing MDU Resources' percentage of operating income and total assets for the regulated natural gas distribution business in each of the past two years.

Response:

Please see Attachment A.

MDU RESOURCES GROUP, INC.

	2011	2010
Operating Income		
Electric	49,096	48,296
Natural gas distribution	82,856	75,697
Pipeline and energy services	45,365	46,310
Exploration and production	133,790	143,169
Construction materials and contracting	51,092	63,045
Construction services	39,144	33,352
Other	5,024	858
Total	406,367	410,727
% Natural gas distribution	**20.39%**	**18.43%**
Assets		
Electric	672,940	643,636
Natural gas distribution	1,679,091	1,632,012
Pipeline and energy services	526,797	523,075
Exploration and production	1,481,556	1,342,808
Construction materials and contracting	1,374,026	1,382,836
Construction services	418,519	387,627
Other	403,196	391,555
Total	6,556,125	6,303,549
% Natural gas distribution	**25.61%**	**25.89%**

Source: MDU Resources Group, Inc. Form 10-K for the fiscal year ended December 31, 2011, at 26 and 82

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-088 RE: Risk Premium Approach
Witness: Stephen Gaske

In reference to your testimony at page 25, lines 14-16: Please provide the annual return on large company common stocks and the return on long-term corporate bonds for each year from 1926-2011.

Response:

Please see Attachment A.

Ibbotson® SBBI®
2012 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2011

MORNINGSTAR®

Table B-1

Large Company Stocks: Total Returns

from January 1926 to December 1970

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1926	0.0000	-0.0385	-0.0575	0.0253	0.0179	0.0457	0.0479	0.0248	0.0252	-0.0284	0.0347	0.0196	1926	0.1162
1927	-0.0193	0.0537	0.0087	0.0201	0.0607	-0.0067	0.0670	0.0515	0.0450	-0.0502	0.0721	0.0279	1927	0.3749
1928	-0.0040	-0.0125	0.1101	0.0345	0.0197	-0.0385	0.0141	0.0803	0.0259	0.0168	0.1292	0.0049	1928	0.4361
1929	0.0583	-0.0019	-0.0012	0.0176	-0.0362	0.1140	0.0471	0.1028	-0.0476	-0.1973	-0.1246	0.0282	1929	-0.0842
1930	0.0639	0.0259	0.0812	-0.0080	-0.0096	-0.1625	0.0386	0.0141	-0.1282	-0.0855	-0.0089	-0.0706	1930	-0.2490
1931	0.0502	0.1193	-0.0675	-0.0935	-0.1279	0.1421	-0.0722	0.0182	-0.2973	0.0896	-0.0798	-0.1400	1931	-0.4334
1932	-0.0271	0.0570	-0.1158	-0.1997	-0.2196	-0.0022	0.3815	0.3869	-0.0346	-0.1349	-0.0417	0.0565	1932	-0.0819
1933	0.0087	-0.1772	0.0353	0.4256	0.1683	0.1338	-0.0862	0.1206	-0.1118	-0.0855	0.1127	0.0253	1933	0.5399
1934	0.1069	-0.0322	0.0000	-0.0251	-0.0736	0.0229	-0.1132	0.0611	-0.0033	-0.0286	0.0942	-0.0010	1934	-0.0144
1935	-0.0411	-0.0341	-0.0286	0.0980	0.0409	0.0699	0.0850	0.0280	0.0256	0.0777	0.0474	0.0394	1935	0.4767
1936	0.0670	0.0224	0.0268	-0.0751	0.0545	0.0333	0.0701	0.0151	0.0031	0.0775	0.0134	-0.0029	1936	0.3392
1937	0.0390	0.0191	-0.0077	-0.0809	-0.0024	-0.0504	0.1045	-0.0483	-0.1403	-0.0981	-0.0866	-0.0459	1937	-0.3503
1938	0.0152	0.0674	-0.2487	0.1447	-0.0330	0.2503	0.0744	-0.0226	0.0166	0.0776	-0.0273	0.0401	1938	0.3112
1939	-0.0674	0.0390	-0.1339	-0.0027	0.0733	-0.0612	0.1105	-0.0648	0.1673	-0.0123	-0.0398	0.0270	1939	-0.0041
1940	-0.0336	0.0133	0.0124	-0.0024	-0.2289	0.0809	0.0341	0.0350	0.0123	0.0422	-0.0316	0.0009	1940	-0.0978
1941	-0.0463	-0.0060	0.0071	-0.0612	0.0183	0.0578	0.0579	0.0010	-0.0068	-0.0657	-0.0284	-0.0407	1941	-0.1159
1942	0.0161	-0.0159	-0.0652	-0.0399	0.0796	0.0221	0.0337	0.0164	0.0290	0.0678	-0.0021	0.0549	1942	0.2034
1943	0.0737	0.0583	0.0545	0.0035	0.0552	0.0223	-0.0526	0.0171	0.0263	-0.0108	-0.0654	0.0617	1943	0.2590
1944	0.0171	0.0042	0.0195	-0.0100	0.0505	0.0543	-0.0193	0.0157	-0.0008	0.0023	0.0133	0.0374	1944	0.1975
1945	0.0158	0.0683	-0.0441	0.0902	0.0195	-0.0007	-0.0180	0.0641	0.0438	0.0322	0.0396	0.0116	1945	0.3644
1946	0.0714	-0.0641	0.0480	0.0393	0.0288	-0.0370	-0.0239	-0.0674	-0.0997	-0.0060	-0.0027	0.0457	1946	-0.0807
1947	0.0255	-0.0077	-0.0149	-0.0363	0.0014	0.0554	0.0381	-0.0203	-0.0111	0.0238	-0.0175	0.0233	1947	0.0571
1948	-0.0379	-0.0388	0.0793	0.0292	0.0879	0.0054	-0.0508	0.0158	-0.0276	0.0710	-0.0961	0.0346	1948	0.0550
1949	0.0039	-0.0296	0.0328	-0.0179	-0.0258	0.0014	0.0650	0.0219	0.0263	0.0340	0.0175	0.0486	1949	0.1879
1950	0.0197	0.0199	0.0070	0.0486	0.0509	-0.0548	0.0119	0.0443	0.0592	0.0093	0.0169	0.0513	1950	0.3171
1951	0.0637	0.0157	-0.0156	0.0509	-0.0299	-0.0228	0.0711	0.0478	0.0013	-0.0103	0.0096	0.0424	1951	0.2402
1952	0.0181	-0.0282	0.0503	-0.0402	0.0343	0.0490	0.0196	-0.0071	-0.0176	0.0020	0.0571	0.0382	1952	0.1837
1953	-0.0049	-0.0106	-0.0212	-0.0237	0.0077	-0.0134	0.0273	-0.0501	0.0034	0.0540	0.0204	0.0053	1953	-0.0099
1954	0.0536	0.0111	0.0325	0.0516	0.0418	0.0031	0.0589	-0.0275	0.0851	-0.0167	0.0909	0.0534	1954	0.5262
1955	0.0197	0.0098	-0.0030	0.0396	0.0055	0.0841	0.0621	-0.0025	0.0130	-0.0284	0.0827	0.0015	1955	0.3156
1956	-0.0347	0.0413	0.0710	-0.0004	-0.0593	0.0409	0.0530	-0.0328	-0.0440	0.0066	-0.0050	0.0370	1956	0.0656
1957	-0.0401	-0.0264	0.0215	0.0388	0.0437	0.0004	0.0131	-0.0505	-0.0602	-0.0302	0.0231	-0.0395	1957	-0.1078
1958	0.0445	-0.0141	0.0328	0.0337	0.0212	0.0279	0.0449	0.0176	0.0501	0.0270	0.0284	0.0535	1958	0.4336
1959	0.0053	0.0049	0.0020	0.0402	0.0240	-0.0022	0.0363	-0.0102	-0.0443	0.0128	0.0186	0.0292	1959	0.1196
1960	-0.0700	0.0147	-0.0123	-0.0161	0.0326	0.0211	-0.0234	0.0317	-0.0590	-0.0007	0.0465	0.0479	1960	0.0047
1961	0.0645	0.0319	0.0270	0.0051	0.0239	-0.0275	0.0342	0.0243	-0.0184	0.0298	0.0447	0.0046	1961	0.2689
1962	-0.0366	0.0209	-0.0046	-0.0607	-0.0811	-0.0803	0.0652	0.0208	-0.0465	0.0064	0.1086	0.0153	1962	-0.0873
1963	0.0506	-0.0239	0.0370	0.0500	0.0193	-0.0188	-0.0022	0.0535	-0.0097	0.0339	-0.0046	0.0262	1963	0.2280
1964	0.0283	0.0147	0.0165	0.0075	0.0162	0.0178	0.0195	-0.0118	0.0301	0.0096	0.0005	0.0056	1964	0.1648
1965	0.0345	0.0031	-0.0133	0.0356	-0.0030	-0.0473	0.0147	0.0272	0.0334	0.0289	-0.0031	0.0106	1965	0.1245
1966	0.0062	-0.0131	-0.0205	0.0220	-0.0492	-0.0146	-0.0120	-0.0725	-0.0053	0.0494	0.0095	0.0002	1966	-0.1006
1967	0.0798	0.0072	0.0409	0.0437	-0.0477	0.0190	0.0468	-0.0070	0.0342	-0.0276	0.0065	0.0278	1967	0.2398
1968	-0.0425	-0.0261	0.0110	0.0834	0.0161	0.0105	-0.0172	0.0164	0.0400	0.0087	0.0531	-0.0402	1968	0.1106
1969	-0.0068	-0.0426	0.0359	0.0229	0.0026	-0.0542	-0.0587	0.0454	-0.0236	0.0459	-0.0297	-0.0177	1969	-0.0850
1970	-0.0743	0.0557	0.0044	-0.0875	-0.0578	-0.0466	0.0769	0.0478	0.0362	-0.0083	0.0506	0.0598	1970	0.0386

*Compound annual return

Table B-1 (Continued)
Large Company Stocks: Total Returns

from January 1971 to December 2011

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1971	0.0432	0.0117	0.0394	0.0389	-0.0391	0.0033	-0.0387	0.0388	-0.0044	-0.0391	0.0002	0.0888	1971	0.1430
1972	0.0206	0.0277	0.0083	0.0068	0.0197	-0.0194	0.0048	0.0369	-0.0025	0.0119	0.0481	0.0142	1972	0.1899
1973	-0.0149	-0.0352	0.0008	-0.0383	-0.0163	-0.0040	0.0407	-0.0341	0.0442	0.0002	-0.1109	0.0198	1973	-0.1469
1974	-0.0072	-0.0007	-0.0205	-0.0359	-0.0302	-0.0114	-0.0742	-0.0864	-0.1152	0.1681	-0.0489	-0.0156	1974	-0.2647
1975	0.1272	0.0638	0.0254	0.0510	0.0476	0.0477	-0.0644	-0.0176	-0.0312	0.0653	0.0282	-0.0081	1975	0.3723
1976	0.1217	-0.0084	0.0337	-0.0078	-0.0111	0.0443	-0.0048	-0.0018	0.0258	-0.0186	-0.0041	0.0561	1976	0.2393
1977	-0.0473	-0.0182	-0.0105	0.0042	-0.0196	0.0494	-0.0124	-0.0172	0.0015	-0.0389	0.0316	0.0075	1977	-0.0716
1978	-0.0574	-0.0203	0.0294	0.0902	0.0092	-0.0138	0.0583	0.0301	-0.0032	-0.0872	0.0215	0.0196	1978	0.0657
1979	0.0443	-0.0321	0.0596	0.0094	-0.0247	0.0435	0.0134	0.0577	0.0043	-0.0640	0.0475	0.0214	1979	0.1861
1980	0.0622	-0.0001	-0.0972	0.0462	0.0515	0.0316	0.0696	0.0101	0.0294	0.0202	0.1065	-0.0302	1980	0.3250
1981	-0.0418	0.0174	0.0400	-0.0193	0.0026	-0.0063	0.0021	-0.0577	-0.0493	0.0540	0.0413	-0.0256	1981	-0.0492
1982	-0.0131	-0.0559	-0.0052	0.0452	-0.0341	-0.0150	-0.0178	0.1214	0.0125	0.1151	0.0404	0.0193	1982	0.2155
1983	0.0372	0.0229	0.0369	0.0788	-0.0087	0.0389	-0.0295	0.0150	0.0138	-0.0116	0.0211	-0.0052	1983	0.2256
1984	-0.0056	-0.0352	0.0173	0.0095	-0.0554	0.0217	-0.0124	0.1104	0.0002	0.0039	-0.0112	0.0263	1984	0.0627
1985	0.0779	0.0122	0.0007	-0.0009	0.0578	0.0157	-0.0015	-0.0085	-0.0313	0.0462	0.0686	0.0484	1985	0.3173
1986	0.0056	0.0747	0.0558	-0.0113	0.0532	0.0169	-0.0559	0.0742	-0.0827	0.0577	0.0243	-0.0255	1986	0.1867
1987	0.1347	0.0395	0.0289	-0.0089	0.0087	0.0505	0.0507	0.0373	-0.0219	-0.2154	-0.0824	0.0761	1987	0.0525
1988	0.0421	0.0466	-0.0309	0.0111	0.0086	0.0459	-0.0038	-0.0339	0.0426	0.0278	-0.0143	0.0174	1988	0.1661
1989	0.0732	-0.0249	0.0233	0.0519	0.0405	-0.0057	0.0903	0.0195	-0.0041	-0.0232	0.0204	0.0240	1989	0.3169
1990	-0.0671	0.0129	0.0265	-0.0249	0.0975	-0.0067	-0.0032	-0.0904	-0.0487	-0.0043	0.0646	0.0279	1990	-0.0310
1991	0.0436	0.0715	0.0242	0.0024	0.0431	-0.0458	0.0466	0.0237	-0.0167	0.0134	-0.0403	0.1144	1991	0.3047
1992	-0.0186	0.0130	-0.0194	0.0294	0.0049	-0.0149	0.0409	-0.0205	0.0118	0.0035	0.0341	0.0123	1992	0.0762
1993	0.0084	0.0136	0.0211	-0.0242	0.0268	0.0029	-0.0040	0.0379	-0.0077	0.0207	-0.0095	0.0121	1993	0.1008
1994	0.0340	-0.0271	-0.0436	0.0128	0.0164	-0.0245	0.0328	0.0410	-0.0245	0.0225	-0.0364	0.0148	1994	0.0132
1995	0.0259	0.0390	0.0295	0.0294	0.0400	0.0232	0.0332	0.0025	0.0422	-0.0036	0.0439	0.0193	1995	0.3758
1996	0.0340	0.0093	0.0096	0.0147	0.0258	0.0038	-0.0442	0.0211	0.0563	0.0276	0.0756	-0.0198	1996	0.2296
1997	0.0625	0.0078	-0.0411	0.0597	0.0609	0.0448	0.0796	-0.0560	0.0548	-0.0334	0.0463	0.0172	1997	0.3336
1998	0.0111	0.0721	0.0512	0.0101	-0.0172	0.0406	-0.0106	-0.1446	0.0641	0.0813	0.0606	0.0576	1998	0.2858
1999	0.0418	-0.0311	0.0400	0.0387	-0.0236	0.0555	-0.0312	-0.0049	-0.0274	0.0633	0.0203	0.0589	1999	0.2104
2000	-0.0502	-0.0189	0.0978	-0.0301	-0.0205	0.0247	-0.0156	0.0621	-0.0528	-0.0042	-0.0788	0.0049	2000	-0.0910
2001	0.0355	-0.0912	-0.0634	0.0777	0.0067	-0.0243	-0.0098	-0.0626	-0.0808	0.0191	0.0767	0.0088	2001	-0.1189
2002	-0.0146	-0.0193	0.0376	-0.0606	-0.0074	-0.0712	-0.0780	0.0066	-0.1087	0.0880	0.0589	-0.0587	2002	-0.2210
2003	-0.0262	-0.0150	0.0097	0.0824	0.0527	0.0128	0.0176	0.0195	-0.0106	0.0566	0.0088	0.0524	2003	0.2868
2004	0.0184	0.0139	-0.0151	-0.0157	0.0137	0.0194	-0.0331	0.0040	0.0108	0.0153	0.0405	0.0340	2004	0.1088
2005	-0.0244	0.0210	-0.0177	-0.0190	0.0318	0.0014	0.0372	-0.0091	0.0081	-0.0167	0.0378	0.0003	2005	0.0491
2006	0.0265	0.0027	0.0124	0.0134	-0.0288	0.0014	0.0062	0.0238	0.0258	0.0326	0.0190	0.0140	2006	0.1579
2007	0.0151	-0.0196	0.0112	0.0443	0.0349	-0.0166	-0.0310	0.0150	0.0374	0.0159	-0.0418	-0.0069	2007	0.0549
2008	-0.0600	-0.0325	-0.0043	0.0487	0.0130	-0.0843	-0.0084	0.0145	-0.0891	-0.1679	-0.0718	0.0106	2008	-0.3700
2009	-0.0843	-0.1065	0.0876	0.0957	0.0559	0.0020	0.0756	0.0361	0.0373	-0.0186	0.0600	0.0193	2009	0.2646
2010	-0.0360	0.0310	0.0603	0.0158	-0.0799	-0.0523	0.0701	-0.0451	0.0892	0.0380	0.0001	0.0668	2010	0.1506
2011	0.0237	0.0343	0.0004	0.0296	-0.0113	-0.0167	-0.0203	-0.0543	-0.0703	0.1093	-0.0022	0.0102	2011	0.0211

*Compound annual return

Table B-5

Long-Term Corporate Bonds: Total Returns

from January 1926 to December 1970

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1926	0.0072	0.0045	0.0084	0.0097	0.0044	0.0004	0.0057	0.0044	0.0057	0.0097	0.0057	0.0056	1926	0.0737
1927	0.0056	0.0069	0.0083	0.0055	-0.0011	0.0043	0.0003	0.0083	0.0149	0.0055	0.0068	0.0068	1927	0.0744
1928	0.0027	0.0068	0.0041	0.0014	-0.0078	-0.0024	-0.0010	0.0083	0.0030	0.0083	-0.0036	0.0084	1928	0.0284
1929	0.0043	0.0030	-0.0087	0.0019	0.0045	-0.0046	0.0020	0.0020	0.0034	0.0073	-0.0018	0.0192	1929	0.0327
1930	0.0059	0.0072	0.0138	0.0084	0.0057	0.0110	0.0056	0.0136	0.0108	0.0054	-0.0012	-0.0090	1930	0.0798
1931	0.0203	0.0068	0.0094	0.0067	0.0134	0.0052	0.0052	0.0012	-0.0014	-0.0363	-0.0189	-0.0286	1931	-0.0185
1932	-0.0052	-0.0238	0.0356	-0.0176	0.0107	-0.0009	0.0043	0.0436	0.0301	0.0074	0.0073	0.0139	1932	0.1082
1933	0.0547	-0.0523	0.0047	-0.0095	0.0588	0.0190	0.0161	0.0093	-0.0014	0.0040	-0.0248	0.0257	1933	0.1038
1934	0.0257	0.0146	0.0187	0.0104	0.0090	0.0158	0.0047	0.0047	-0.0061	0.0102	0.0129	0.0101	1934	0.1384
1935	0.0211	0.0141	0.0043	0.0112	0.0042	0.0112	0.0111	-0.0042	0.0000	0.0042	0.0069	0.0083	1935	0.0961
1936	0.0082	0.0054	0.0082	0.0026	0.0040	0.0082	0.0011	0.0067	0.0067	0.0025	0.0109	0.0010	1936	0.0674
1937	0.0024	-0.0046	-0.0114	0.0068	0.0040	0.0053	0.0039	-0.0017	0.0025	0.0067	0.0067	0.0067	1937	0.0275
1938	0.0038	0.0010	-0.0087	0.0138	0.0010	0.0095	0.0066	-0.0019	0.0109	0.0080	0.0037	0.0122	1938	0.0613
1939	0.0022	0.0064	0.0022	0.0064	0.0049	0.0035	-0.0007	-0.0392	0.0151	0.0237	0.0079	0.0078	1939	0.0397
1940	0.0049	0.0021	0.0049	-0.0092	-0.0021	0.0121	0.0021	0.0007	0.0092	0.0049	0.0063	-0.0023	1940	0.0339
1941	0.0006	0.0006	-0.0022	0.0078	0.0049	0.0063	0.0063	0.0034	0.0048	0.0034	-0.0094	0.0006	1941	0.0273
1942	0.0006	-0.0008	0.0063	0.0006	0.0020	0.0034	0.0020	0.0035	0.0020	0.0006	0.0006	0.0049	1942	0.0260
1943	0.0049	0.0006	0.0020	0.0049	0.0048	0.0048	0.0019	0.0019	0.0005	-0.0009	-0.0023	0.0049	1943	0.0283
1944	0.0020	0.0034	0.0048	0.0034	0.0005	0.0020	0.0034	0.0034	0.0019	0.0019	0.0048	0.0149	1944	0.0473
1945	0.0076	0.0046	0.0018	0.0018	-0.0011	0.0032	-0.0011	0.0004	0.0032	0.0032	0.0032	0.0133	1945	0.0408
1946	0.0128	0.0034	0.0034	-0.0043	0.0019	0.0019	-0.0012	-0.0088	-0.0026	0.0020	-0.0025	0.0113	1946	0.0172
1947	0.0005	0.0005	0.0067	0.0020	0.0020	0.0004	0.0020	-0.0071	-0.0131	-0.0099	-0.0098	0.0024	1947	-0.0234
1948	0.0024	0.0039	0.0115	0.0038	0.0008	-0.0083	-0.0052	0.0055	0.0024	0.0024	0.0085	0.0131	1948	0.0414
1949	0.0038	0.0038	0.0007	0.0023	0.0038	0.0084	0.0099	0.0037	0.0021	0.0067	0.0021	-0.0145	1949	0.0331
1950	0.0037	0.0007	0.0022	-0.0008	-0.0008	0.0023	0.0069	0.0038	-0.0039	-0.0008	0.0054	0.0023	1950	0.0212
1951	0.0019	-0.0044	-0.0237	-0.0009	-0.0015	-0.0093	0.0205	0.0114	-0.0057	-0.0145	-0.0061	0.0058	1951	-0.0269
1952	0.0199	-0.0085	0.0076	-0.0004	0.0031	0.0016	0.0016	0.0063	-0.0018	0.0039	0.0108	-0.0091	1952	0.0352
1953	-0.0080	-0.0040	-0.0033	-0.0248	-0.0030	0.0109	0.0177	-0.0085	0.0253	0.0227	-0.0073	0.0172	1953	0.0341
1954	0.0124	0.0198	0.0039	-0.0034	-0.0042	0.0063	0.0040	0.0018	0.0040	0.0040	0.0025	0.0017	1954	0.0539
1955	-0.0097	-0.0063	0.0092	-0.0001	-0.0018	0.0029	-0.0041	-0.0038	0.0076	0.0078	-0.0030	0.0063	1955	0.0048
1956	0.0104	0.0026	-0.0146	-0.0115	0.0052	-0.0018	-0.0093	-0.0208	0.0012	-0.0105	-0.0126	-0.0082	1956	-0.0681
1957	0.0197	0.0093	0.0050	-0.0066	-0.0075	-0.0322	-0.0110	-0.0009	0.0095	0.0023	0.0311	0.0685	1957	0.0871
1958	0.0099	-0.0008	-0.0046	0.0163	0.0031	-0.0038	-0.0153	-0.0320	-0.0096	0.0107	0.0105	-0.0058	1958	-0.0222
1959	-0.0028	0.0126	-0.0083	-0.0172	-0.0114	0.0044	0.0089	-0.0068	-0.0088	0.0165	0.0135	-0.0096	1959	-0.0097
1960	0.0107	0.0128	0.0191	-0.0022	-0.0021	0.0141	0.0257	0.0117	-0.0063	0.0008	-0.0070	0.0104	1960	0.0907
1961	0.0148	0.0210	-0.0029	-0.0116	0.0049	-0.0080	0.0040	-0.0018	0.0144	0.0127	0.0028	-0.0026	1961	0.0482
1962	0.0080	0.0052	0.0151	0.0142	0.0000	-0.0026	-0.0015	0.0143	0.0089	0.0068	0.0062	0.0023	1962	0.0795
1963	0.0059	0.0023	0.0026	-0.0051	0.0048	0.0043	0.0028	0.0035	-0.0023	0.0049	0.0015	-0.0034	1963	0.0219
1964	0.0087	0.0054	-0.0062	0.0040	0.0057	0.0048	0.0052	0.0037	0.0021	0.0050	-0.0004	0.0088	1964	0.0477
1965	0.0081	0.0009	0.0012	0.0021	-0.0008	0.0003	0.0019	-0.0006	-0.0015	0.0046	-0.0057	-0.0149	1965	-0.0046
1966	0.0022	-0.0113	-0.0059	0.0013	-0.0026	0.0030	-0.0098	-0.0259	0.0078	0.0261	-0.0020	0.0201	1966	0.0020
1967	0.0450	-0.0201	0.0117	-0.0071	-0.0254	-0.0223	0.0041	-0.0007	0.0094	-0.0281	-0.0272	0.0127	1967	-0.0495
1968	0.0361	0.0037	-0.0197	0.0048	0.0032	0.0122	0.0341	0.0206	-0.0053	-0.0160	-0.0226	-0.0233	1968	0.0257
1969	0.0139	-0.0160	-0.0200	0.0335	-0.0227	0.0035	0.0005	-0.0020	-0.0244	0.0127	-0.0471	-0.0134	1969	-0.0809
1970	0.0141	0.0401	-0.0045	-0.0250	-0.0163	0.0001	0.0556	0.0100	0.0139	-0.0096	0.0584	0.0372	1970	0.1837

*Compound annual return

Table B-5 (Continued)
Long-Term Corporate Bonds: Total Returns

from January 1971 to December 2011

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1971	0.0532	-0.0366	0.0258	-0.0236	-0.0161	0.0107	-0.0025	0.0554	-0.0102	0.0282	0.0029	0.0223	1971	0.1101
1972	-0.0033	0.0107	0.0024	0.0035	0.0163	-0.0068	0.0030	0.0072	0.0031	0.0101	0.0249	-0.0004	1972	0.0726
1973	-0.0054	0.0023	0.0045	0.0061	-0.0039	-0.0056	-0.0476	0.0356	0.0356	-0.0066	0.0078	-0.0089	1973	0.0114
1974	-0.0053	0.0009	-0.0307	-0.0341	0.0105	-0.0285	-0.0211	-0.0268	0.0174	0.0885	0.0117	-0.0075	1974	-0.0306
1975	0.0596	0.0137	-0.0247	-0.0052	0.0106	0.0304	-0.0030	-0.0175	-0.0126	0.0553	-0.0088	0.0442	1975	0.1464
1976	0.0188	0.0061	0.0167	-0.0015	-0.0103	0.0150	0.0149	0.0231	0.0167	0.0070	0.0319	0.0347	1976	0.1865
1977	-0.0303	-0.0020	0.0094	0.0100	0.0106	0.0175	-0.0005	0.0136	-0.0022	-0.0038	0.0061	-0.0105	1977	0.0171
1978	-0.0089	0.0051	0.0042	-0.0023	-0.0108	0.0023	0.0101	0.0257	-0.0048	-0.0205	0.0134	-0.0133	1978	-0.0007
1979	0.0184	-0.0128	0.0106	-0.0052	0.0228	0.0269	-0.0031	0.0006	-0.0179	-0.0890	0.0222	-0.0108	1979	-0.0418
1980	-0.0645	-0.0665	-0.0062	0.1376	0.0560	0.0341	-0.0429	-0.0445	-0.0237	-0.0159	0.0017	0.0248	1980	-0.0276
1981	-0.0130	-0.0269	0.0311	-0.0769	0.0595	0.0023	-0.0372	-0.0345	-0.0199	0.0521	0.1267	-0.0580	1981	-0.0124
1982	-0.0129	0.0312	0.0306	0.0338	0.0245	-0.0468	0.0540	0.0837	0.0623	0.0759	0.0201	0.0108	1982	0.4256
1983	-0.0094	0.0428	0.0072	0.0548	-0.0324	-0.0046	-0.0455	0.0051	0.0392	-0.0025	0.0142	-0.0033	1983	0.0626
1984	0.0270	-0.0172	-0.0235	-0.0073	-0.0483	0.0199	0.0586	0.0307	0.0314	0.0572	0.0212	0.0128	1984	0.1686
1985	0.0325	-0.0373	0.0179	0.0296	0.0820	0.0083	-0.0121	0.0260	0.0071	0.0329	0.0370	0.0469	1985	0.3009
1986	0.0045	0.0752	0.0256	0.0016	-0.0164	0.0218	0.0031	0.0275	-0.0114	0.0189	0.0233	0.0117	1986	0.1985
1987	0.0216	0.0058	-0.0087	-0.0502	-0.0052	0.0155	-0.0119	-0.0075	-0.0422	0.0507	0.0125	0.0212	1987	-0.0027
1988	0.0517	0.0138	-0.0188	-0.0149	-0.0057	0.0379	-0.0111	0.0054	0.0326	0.0273	-0.0169	0.0039	1988	0.1070
1989	0.0202	-0.0129	0.0064	0.0213	0.0379	0.0395	0.0178	-0.0163	0.0040	0.0276	0.0070	0.0006	1989	0.1623
1990	-0.0191	-0.0012	-0.0011	-0.0191	0.0385	0.0216	0.0102	-0.0292	0.0091	0.0132	0.0285	0.0167	1990	0.0678
1991	0.0150	0.0121	0.0108	0.0138	0.0039	-0.0018	0.0167	0.0275	0.0271	0.0043	0.0106	0.0436	1991	0.1989
1992	-0.0173	0.0096	-0.0073	0.0016	0.0254	0.0156	0.0308	0.0090	0.0099	-0.0156	0.0069	0.0228	1992	0.0939
1993	0.0250	0.0256	0.0025	0.0052	0.0020	0.0293	0.0100	0.0287	0.0043	0.0051	-0.0188	0.0067	1993	0.1319
1994	0.0202	-0.0286	-0.0383	-0.0097	-0.0062	-0.0081	0.0309	-0.0031	-0.0265	-0.0050	0.0018	0.0157	1994	-0.0576
1995	0.0256	0.0289	0.0095	0.0175	0.0631	0.0079	-0.0101	0.0214	0.0153	0.0185	0.0242	0.0228	1995	0.2720
1996	0.0014	-0.0373	-0.0130	-0.0160	0.0005	0.0172	0.0010	-0.0070	0.0259	0.0361	0.0263	-0.0186	1996	0.0140
1997	-0.0028	0.0028	-0.0221	0.0184	0.0128	0.0187	0.0528	-0.0240	0.0226	0.0191	0.0101	0.0163	1997	0.1295
1998	0.0137	-0.0007	0.0038	0.0053	0.0167	0.0115	-0.0056	0.0089	0.0413	-0.0190	0.0270	0.0010	1998	0.1076
1999	0.0123	-0.0401	0.0002	-0.0024	-0.0176	-0.0160	-0.0113	-0.0026	0.0093	0.0047	-0.0024	-0.0102	1999	-0.0745
2000	-0.0021	0.0092	0.0169	-0.0115	-0.0161	0.0326	0.0179	0.0135	0.0046	0.0045	0.0263	0.0270	2000	0.1287
2001	0.0359	0.0127	-0.0029	-0.0128	0.0132	0.0055	0.0361	0.0157	-0.0152	0.0437	-0.0188	-0.0090	2001	0.1065
2002	0.0175	0.0130	-0.0295	0.0253	0.0113	0.0073	0.0094	0.0452	0.0330	-0.0240	0.0103	0.0361	2002	0.1633
2003	0.0021	0.0264	-0.0080	0.0229	0.0471	-0.0143	-0.0881	0.0219	0.0503	-0.0203	0.0052	0.0139	2003	0.0527
2004	0.0187	0.0178	0.0118	-0.0534	-0.0071	0.0093	0.0184	0.0395	0.0101	0.0164	-0.0200	0.0257	2004	0.0872
2005	0.0277	-0.0112	-0.0125	0.0327	0.0295	0.0141	-0.0244	0.0233	-0.0310	-0.0204	0.0099	0.0225	2005	0.0587
2006	-0.0093	0.0128	-0.0404	-0.0224	-0.0020	0.0039	0.0237	0.0361	0.0183	0.0127	0.0246	-0.0232	2006	0.0324
2007	-0.0051	0.0287	-0.0231	0.0140	-0.0178	-0.0148	-0.0032	0.0152	0.0135	0.0088	0.0079	0.0028	2007	0.0260
2008	0.0017	-0.0071	-0.0059	0.0091	-0.0277	-0.0061	-0.0109	0.0121	-0.0863	-0.0450	0.1174	0.1560	2008	0.0878
2009	-0.0949	-0.0308	-0.0018	-0.0030	0.0489	0.0350	0.0565	0.0235	0.0273	0.0016	0.0044	-0.0275	2009	0.0302
2010	0.0096	0.0039	0.0045	0.0357	-0.0051	0.0519	0.0170	0.0473	-0.0144	-0.0203	-0.0057	-0.0036	2010	0.1244
2011	-0.0198	0.0157	-0.0072	0.0239	0.0257	-0.0210	0.0473	0.0240	0.0575	0.0094	-0.0356	0.0512	2011	0.1795

*Compound annual return

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-089 RE: Risk Premium Approach
Witness: Stephen Gaske

Please provide a copy of the 2012 Ibbotson Valuation Yearbook, page 23 and 2012 Ibbotson Valuation Yearbook, pages 23, 88 and 202, as referenced in your testimony at footnote 11, page 25 and footnote 12, page 26 respectively.

Response:

Please see Attachment A.

Ibbotson® SBBI®
2012 Valuation Yearbook

Market Results for Stocks, Bonds, Bills, and Inflation 1926–2011

MORNINGSTAR®

Table 2-1: Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes: Summary Statistics of Annual Returns

Series	Geometric Mean (%)	Arithmetic Mean (%)	Standard Deviation (%)	Serial Correlation
Large Company Stocks				
Total Returns	9.8	11.8	20.3	0.02
Income	4.1	4.1	1.6	0.90
Capital Appreciation	5.5	7.4	19.6	0.01
Ibbotson Small Company Stocks				
Total Returns	11.9	16.5	32.5	0.06
Mid-Cap Stocks*				
Total Returns	10.9	13.7	24.8	-0.04
Income	3.9	3.9	1.8	0.90
Capital Appreciation	6.8	9.6	24.1	-0.04
Low-Cap Stocks*				
Total Returns	11.3	15.2	29.2	0.02
Income	3.5	3.6	2.0	0.90
Capital Appreciation	7.6	11.4	28.5	0.01
Micro-Cap Stocks*				
Total Returns	12.0	18.0	38.9	0.07
Income	2.5	2.5	1.7	0.91
Capital Appreciation	9.5	15.4	38.3	0.06
Long-Term Corporate Bonds				
Total Returns	6.1	6.4	8.4	0.08
Long-Term Government Bonds				
Total Returns	5.7	6.1	9.8	-0.11
Income	5.1	5.2	2.6	0.96
Capital Appreciation	0.4	0.8	8.7	-0.23
Intermediate-Term Government Bonds				
Total Returns	5.4	5.5	5.7	0.13
Income	4.6	4.6	2.9	0.96
Capital Appreciation	0.6	0.7	4.6	-0.17
Treasury Bills				
Total Returns	3.6	3.6	3.1	0.91
Inflation	3.0	3.1	4.2	0.64

Data from 1926–2011. Total return is equal to the sum of three component returns: income return, capital appreciation return, and reinvestment return.

*Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2012 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

Annual Total Returns

Annual and monthly total returns for large company stocks, small company stocks, long-term corporate bonds, long-term government bonds, intermediate-term government bonds, Treasury bills, and inflation rates are for the full 86-year time period presented in Appendix B. Those tables can be used to compare the performance of each asset class on both a monthly and an annual basis.

Real Rates versus Nominal Rates

The cost of capital embodies a number of different concepts or elements of risk. Two of the most basic concepts in finance are real and nominal returns. The nominal return includes both the real return and the impact of inflation.

The real rate of interest represents the exchange rate between current and future purchasing power. An increase in the real rate indicates that the cost of current consumption has risen in terms of future goods. It is the real rate of interest that measures the opportunity cost of foregoing consumption.

The relationship between real rates and nominal rates can be expressed in the following equation:

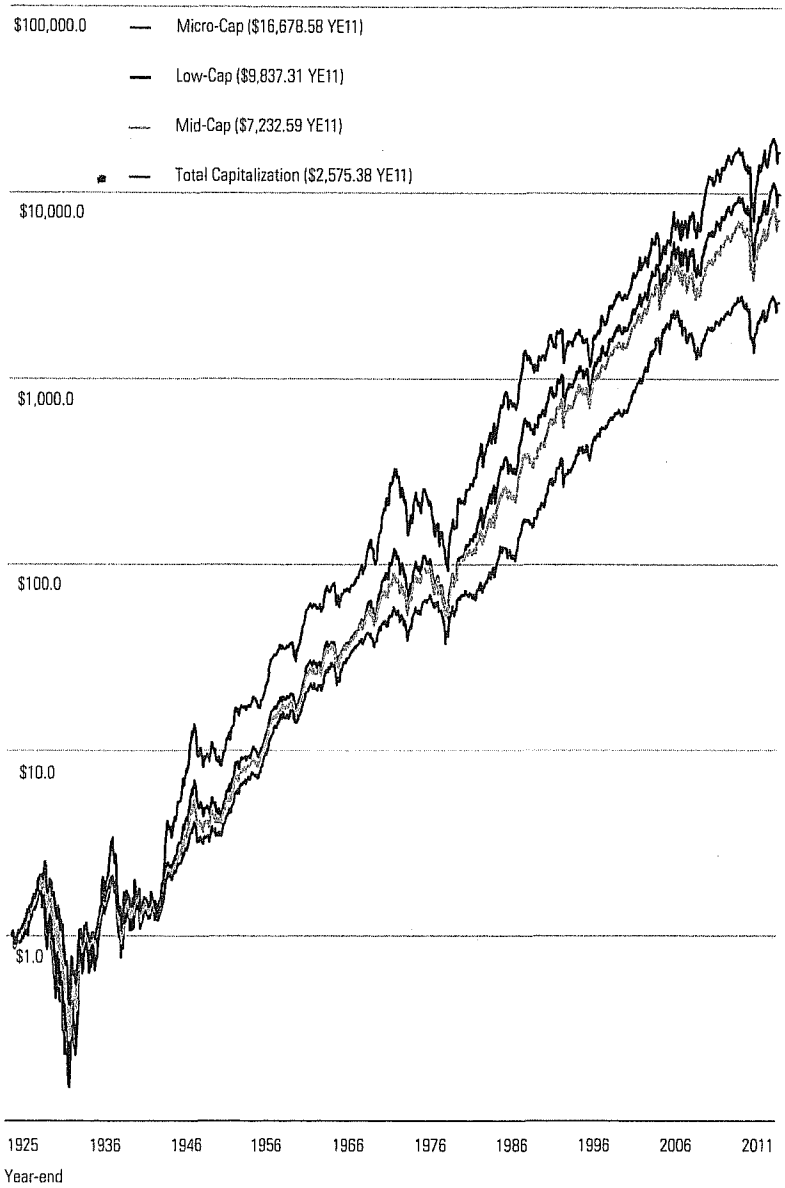
$$\text{Real} = \left[\frac{1+\text{Nominal}}{1+\text{Inflation}}\right] - 1$$

$$\text{Nominal} = \left[(1+\text{Real}) \times (1+\text{Inflation})\right] - 1$$

It is important to note that the conversion of nominal and real rates is not an additive process; rather, it is a geometric calculation. The arithmetic sum or difference is calculated by adding or subtracting one number from the other. As illustrated in the above equation, the real rate of return involves taking the geometric difference of the nominal rate of return and the rate of inflation. Conversely, the nominal rate of return can be determined by taking the geometric sum of the real rate of return and the rate of inflation. For example, if the real rate is 2.5 percent and the inflation rate is 5.0 percent, the nominal rate of interest is not 7.5 percent (2.5+5.0) but 7.625 percent, or $[(1.025)\times(1.05)-1]$. Similarly, if the nominal rate is 7.625 percent and the inflation rate is 2.5 percent, the real rate is not 5.125 percent (7.625−2.5) but 5.0 percent, $[(1.07625/1.025)-1]$.

Discount rates are most often expressed in nominal terms. That is, they usually have an inflation estimate included in them. Unless stated otherwise, the cost of capital data presented in this book are expressed in nominal terms.

Graph 7-1: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ
Wealth Indices of Investments in Mid-, Low-, Micro-, and Total Capitalization Stocks
Index (Year-End 1925 = $1.00)



Data from 1925–2011.

Graph 7-1 depicts the growth of one dollar invested in each of three NYSE/AMEX/NASDAQ groups broken down into mid-cap, low-cap, and micro-cap stocks. The index value of the entire NYSE/AMEX/NASDAQ is also included. All returns presented are value-weighted based on the market capitalizations of the deciles contained in each subgroup. The sheer magnitude of the size effect in some years is noteworthy. While the largest stocks actually declined 9 percent in 1977, the smallest stocks rose more than 20 percent. A more extreme case occurred in the depression-recovery year of 1933, when the difference between the first and tenth decile returns was far more substantial, with the largest stocks rising 46 percent, and the smallest stocks rising 218 percent. This divergence in the performance of small and large company stocks is a common occurrence.

Table 7-4: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ
Summary Statistics of Annual Returns

Decile	Geometric Mean	Arithmetic Mean	Standard Deviation	Serial Correlation
1-Largest	9.0	10.8	19.2	0.07
2	10.4	12.8	22.2	0.01
3	10.8	13.4	23.7	-0.04
4	10.7	13.8	25.9	-0.03
5	11.3	14.6	26.7	-0.04
6	11.2	14.8	27.3	0.02
7	11.2	15.1	29.6	0.00
8	11.4	16.3	34.2	0.04
9	11.5	16.9	36.3	0.04
10-Smallest	12.9	20.6	44.8	0.14
Mid Cap	10.9	13.7	24.8	-0.04
Low Cap	11.3	15.2	29.2	0.02
Micro	12.0	18.0	38.9	0.07
NYSE/AMEX/ NASDAQ Total Value Weighted Index	9.6	11.6	20.3	0.02

Data from 1926–2011. Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2012 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

Results are for quarterly re-ranking for the deciles. The small company stock summary statistics presented in earlier chapters comprise a re-ranking of the portfolios every five years prior to 1982.

Aspects of the Firm Size Effect

The firm size phenomenon is remarkable in several ways. First, the greater risk of small stocks does not, in the context of the capital asset pricing model (CAPM), fully account for their higher returns over the long term. In the CAPM only systematic, or beta risk, is rewarded; small company stocks have had returns in excess of those implied by their betas.

Second, the calendar annual return differences between small and large companies are serially correlated. This suggests that past annual returns may be of some value in predicting future annual returns. Such serial correlation, or autocorrelation, is practically unknown in the market for large stocks and in most other equity markets but is evident in the size premia.

Table C-1
Key Variables in Estimating the Cost of Capital

	Value
Yields (Riskless Rates)[1]	
Long-term (20-year) U.S. Treasury Coupon Bond Yield	2.48%
Equity Risk Premium[2]	
Long-horizon expected equity risk premium (historical): large company stock total returns minus long-term government bond income returns	6.62
Long-horizon expected equity risk premium (supply side): historical equity risk premium minus price-to-earnings ratio calculated using three-year average earnings	6.14

Size Premium[3]

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
Mid-Cap (3–5)	$1,621.096	–	$6,896.389	1.14%
Low-Cap (6–8)	422.999	–	1,620.860	1.88
Micro-Cap (9–10)	1.028	–	422.811	3.89
Breakdown of Deciles 1-10				
1-Largest	15,484.940	–	354,351.912	-0.38
2	6,927.557	–	15,408.314	0.78
3	3,596.535	–	6,896.389	0.94
4	2,366.464	–	3,577.774	1.17
5	1,621.096	–	2,362.532	1.74
6	1,090.652	–	1,620.860	1.75
7	683.059	–	1,090.515	1.77
8	422.999	–	682.750	2.51
9	206.802	–	422.811	2.80
10-Smallest	1.028		206.795	6.10
Breakdown of the 10th Decile				
10a	128.714	–	206.795	4.34
10w	170.605	–	206.795	3.80
10x	128.714	–	170.594	4.75
10b	1.028	–	128.672	9.81
10y	86.875	–	128.672	8.93
10z	1.028	–	86.757	11.77

[1] As of December 31, 2011. Maturity is approximate.
[2] See chapter 5 for complete methodology.
[3] See chapter 7 for complete methodology.

Note: Examples on how these variables can be used are found in Chapters 3 and 4.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-090 **RE: Regulatory Risk**
Witness: Stephen Gaske

Please provide a copy of the document Regulatory Research Associates, Montana State Commission Profile, accessed June 22, 2012, as referenced in your testimony at footnote 15, page 31.

Response:

Please see Attachment A.

Regulatory Research Associates
REGULATORY FOCUS

MONTANA REGULATORY REVIEW -- JUNE 8, 2011

Montana Public Service Commission (PSC)
1701 Prospect Avenue
P.O. Box 202601
Helena, MT 59620-2601
(406) 444-6199

Please note that the sections below are updated through 6/8/11, but are maintained on a real-time basis in the Commission Profiles section of our website.

No. of Commissioners	5 full-time
Method of Selection	Elected in statewide elections
Term of Office	4 years -- staggered terms
Chairman	Elected by fellow Commissioners for a two-year term
Governor	Brian Schweitzer (D)--serving a four-year term that extends to January 2013

Commissioners	Party	Began Serv.	Term Ends	Background
Travis Kavulla (Chairman)	R	1/11	1/15	Freelance journalist; Gates Scholar; editor
Gail Gutsche (Vice Chairman)	D	1/09	1/13	State Legislator; small business owner
Brad Molnar	R	1/05	1/13	State Legislator; building contractor
John Vincent	D	1/09	1/13	State Legislator; Speaker of the Montana House of Representatives
Bill Gallagher	R	1/11	1/15	Farmer; hotel owner and operator; insurance sales manager

Miscellaneous Issues:

Commissioner Selection--Commissioners are elected in statewide elections from each of five districts.

Services Regulated--In addition to private and investor-owned electric and gas utilities, as well as telecommunications and water utilities, the PSC regulates buses, taxicabs, motor carriers, and utility securities issuances.

Staff Contact--Kate Whitney, Administrator, Utility Division (406) 444-3056 (Section updated 6/8/11)

RRA Evaluation:

We view the Montana regulatory environment as somewhat restrictive from an investor perspective. While a recent rate case was resolved via a settlement that included a return on equity that was slightly above industry averages, the PSC commonly authorizes equity returns that are slightly below prevailing industry averages. After almost a decade of indecision, in 2007, the state finally abandoned its move towards implementing retail competition in the electric industry. Around the same time, the Commission rejected the proposed merger of NorthWestern Corp. and Babcock & Brown Infrastructure Ltd. Although NorthWestern sold its generation assets during the state's flirtation with retail competition, utilities are now permitted to seek PSC pre-approval for new generation resource additions. However, inclusion of construction work in progress in rate base is not permitted, which contributes to regulatory lag. By comparison, the gas arena has been more stable, as full retail choice has been in place for more than a decade, and gas utilities are now permitted to acquire upstream assets. Both the electric and gas utilities have mechanisms in place that facilitate the recovery of commodity and related costs. In a recent PSC action of note, the Commission authorized one of the state's utilities to implement a pilot decoupling mechanism for small-volume electric customers.

However, the decision has been appealed and the parties have reached an agreement calling for the mechanism to be terminated. We continue to accord Montana regulation a Below Average/1 rating. (Section updated 6/8/11)

Department Budget: The PSC's fiscal-2011 budget is approximately $3.5 million, derived from a tax on utility revenues. (Section updated 6/8/11)

Commissioner Salaries: Chairman-$88,500, Commissioners-$87,600 (Section updated 6/8/11)

Commission Staff: The PSC Staff consists of 34 members. (Section updated 6/8/11)

Consumer Interest: The consumer interest is represented by the Montana Consumer Counsel (MCC). The MCC, which operates independently of the PSC, is appointed by the Legislature's Consumer Committee for an unspecified term. The current MCC, Robert Nelson, has held the position since 1988. (Section updated 6/8/11)

Rate Case Timing/ Interim Procedures: The PSC must render a final decision in a rate case within nine months of a filing. If no order has been issued by the end of the nine-month period, the utility may place a requested increase into effect, subject to refund. We note that a recent (decided in December 2010) NorthWestern Corp. rate case took over a year to complete; the case was delayed due to the PSC's finding that the company's rate application did not meet the state's minimum filing requirements. In most rate cases, the Commission has authorized interim rate changes on a subject to refund basis, usually within two to four months after the date of filing. (Section updated 6/8/11)

Return on Equity: The most recent rate case decision that specified a return on equity (ROE) was issued on Dec. 9, 2010, when the PSC adopted modified electric and gas rate settlements for NorthWestern Corp., authorizing the company a 10% ROE for its electric operations and a 10.25% ROE for its gas operations. In that decision, the Commission reduced the electric ROE agreed to by the parties by 25 basis points to 10%. We note that NorthWestern and the PSC Staff have reached an agreement in an appeal of the case that would, among other things, restore the authorized ROE to 10.25%. The appeal is pending. Previously, in 2008, in the context of a proceeding in which NorthWestern sought approval to include its ownership interest in the Colstrip Unit 4 plant in rate base, the PSC approved a 10% ROE for the company's investment in the facility (FN 11/14/08). In 2009, in the context of a proceeding in which NorthWestern applied for PSC approval to construct the Mill Creek plant, the PSC adopted a 10.25% ROE for the company's investment in that facility (FN 5/22/09). NorthWestern does business in the state as NorthWestern Energy. In 2008, the PSC established a 10.25% ROE for MDU Resources' (MDU's) electric operations following a settlement. MDU is authorized a 12% ROE for its gas operations, as established in 1996 in a small rate case. MDU does business in Montana as Montana-Dakota Utilities. (Section updated 6/8/11)

Rate Base and Test Period: The PSC generally relies on an average original-cost rate base for a historical test period, adjusted for known-and-measurable changes within 12 months beyond the end of the test period. The PSC generally does not permit construction work in progress to be included in rate base. (Section updated 6/8/11)

Alternative Regulation: State statutes allow the PSC to approve up to a 200-basis-point return on equity (ROE) premium for demand-side management program investments. To date, no such premium has been requested. From 1996 through 1998, NorthWestern Corp. (then Montana Power) operated under an electric alternative regulation plan, that provided for earnings in excess of an 11.4% ROE to be shared equally with ratepayers.

MDU Resources (MDU) utilizes a monthly fuel and purchased power cost adjustment mechanism. Incremental changes in fuel and purchased power costs, and off-system sales margins are to be shared by ratepayers and shareholders on a 90%/10% basis through this mechanism, which is to terminate on Dec. 31, 2011, unless extended by the PSC. (Section updated 6/8/11)

Court Actions: PSC decisions may be appealed first to a Montana District Court and then to the

State Supreme Court. On Jan. 26, 2011, NorthWestern Corp. filed an appeal with the District Court regarding the PSC's Dec. 9, 2010 decision in a general rate proceeding (FN 2/18/11). The parties to the appeal have reached an agreement calling for, among other things, the company's authorized ROE for electric operations to be raised to 10.25%, and for NorthWestern to terminate its pilot electric decoupling mechanism (See the Return on Equity and Adjustment Clauses sections). The appeal is pending. (Section updated 6/8/11)

Legislation:

The Montana Legislature convenes on the first Monday in January in odd-numbered years for a maximum of 90 legislative days. The Senate currently has 28 Republicans and 22 Democrats, and the House of Representatives has 68 Republicans and 32 Democrats. The 2011 session adjourned on April 28.

On March 25, 2011, H.B. 92 was enacted, requiring the PSC to utilize an avoided-cost approach to establish long-term purchased power contracts between qualifying small power producers and the state's electric utilities.

On April 28, 2011, Gov. Schweitzer vetoed House Bill (H.B.) 59, legislation that would have expanded the established parameters for qualifying hydro facilities from which electric utilities could have procured power in order to comply with the state's renewable portfolio standards. Gov. Schweitzer also vetoed similar legislation, Senate Bill 109, on April 13, 2011. (Section updated 6/8/11)

Corporate Governance:

Generic/Legislation--The PSC has authority over mergers involving utilities (see the Merger Activity section), corporate reorganizations, affiliate relationships, and securities issuances. The PSC is statutorily authorized to review and approve "material affiliate transactions" including: dividend payments from a regulated energy utility to a corporate parent company, as the PSC may limit such payments if the proposed amounts would place the regulated energy utility's credit quality or property in jeopardy; inter-company loans or other extensions of credit or advances of working capital between a regulated energy utility and an affiliate; the use of proceeds from security issuances for which the assets of the regulated energy utility are pledged; and, external borrowing of a regulated energy utility with a term greater than 120 days. Utilities that have signed settlements with the PSC (e.g., NorthWestern Corp. -- see below) regarding the separation of their non-regulated businesses are exempt from the statute's requirements.

In 2004, the PSC approved a settlement that resolved an investigation into NorthWestern's financial condition and affiliate transactions. The Consent Order incorporated the provisions of a settlement that had been filed in NorthWestern's bankruptcy proceeding, including: the separation of NorthWestern's utility assets from unregulated operations, with all debt associated with non-utility assets or activities to be held by affiliates or subsidiaries and to be non-recourse to the parent company; and, limits on non-utility investments until the company achieves a credit rating of BBB+. The U.S. Bankruptcy Court subsequently adopted the settlement. In late-2004, the Court approved NorthWestern's amended Chapter 11 reorganization plan, and the plan became effective upon the company's emergence from bankruptcy in November 2004. (Section updated 6/8/11)

Merger Activity:

In 1998, the PSC approved the sale of PacifiCorp's electric operations in Montana to Flathead Electric Cooperative; the merger was completed in 1999. In 2002, the PSC adopted a settlement that approved NorthWestern Corp.'s acquisition of the electric and gas distribution assets owned by Montana Power (MP). The settlement and PSC order provided for the implementation of a $30 million customer credit for one year beginning July 1, 2002, and the recovery of $244.7 million in electric restructuring transition costs over 27 years through a competitive transition charge. This surcharge is to remain in place despite the state's return to a traditional regulatory paradigm. The acquisition was subsequently completed, and NorthWestern began operating the former MP assets as NorthWestern Energy.

In 2004, the PSC issued a statement of criteria to be utilized for evaluating proposals to acquire NorthWestern. At that time, the Commission stated that, in accordance with past PSC practice, it would assert its authority to review any sale or transfer of NorthWestern's Montana-jurisdictional operations. The PSC noted that the settlement reached in the context of NorthWestern's bankruptcy case in

2004 (see the Corporate Governance section) would be binding on any successor company. The PSC stated that an acquirer of the company should be a financially stable, investment-grade utility, and that any acquisition premium would not be recoverable through rates. In addition, the acquirer must: be committed to fund the company's pension plan at a level not below NorthWestern's then-current funding forecast; be committed to long-term ownership of the utility; show a "demonstrable Montana focus" that would occur through the maintenance of a Montana headquarters of either the company or a separate Montana utility subsidiary; have no operating ties to South Dakota or Nebraska; have strong utility management experience; and, demonstrate "financial and management ability to acquire an appropriate electricity supply under the Commission's guidelines."

In 2006, NorthWestern and Babcock & Brown Infrastructure Ltd. (B&B) reached a definitive agreement, whereby B&B would acquire NorthWestern. However, the PSC ultimately rejected the merger, finding that the proposed transaction presented "risk of harm to NorthWestern's financial integrity" and to Montana ratepayers. Specifically, the PSC opined that "the proposed ownership of NorthWestern presents the likelihood that NorthWestern's capital structure will deteriorate and become unacceptably leveraged" due to B&B's intention "to extract excessive equity" from NorthWestern in order to recover the merger acquisition premium. In accordance with the terms of the PSC's bankruptcy-related Consent Order and aforementioned statement of criteria, the companies had agreed that: NorthWestern's utility assets would be owned and operated independently from Babcock & Brown's other businesses; NorthWestern would not pledge its Montana assets to secure the indebtedness or provide financing to affiliated businesses, except in accordance with state statutes; NorthWestern would not enter into any contract with an affiliate for which the costs would be recovered in utility rates, except in accordance with state statutes; and, NorthWestern would maintain separate books for its utility operations. (Section updated 6/8/11)

Electric Regulatory Reform/ Industry Restructuring:

Legislation--Legislation enacted in 1997 required full retail competition to be implemented for customers of NorthWestern Corp. (then Montana Power) by July 1, 2007. As per the law, the company sold its generation assets in 1999 and subsequently entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort (POLR) customers. Legislation enacted in 2003 amended the law by delaying the implementation date of full retail competition to July 1, 2027 from July 1, 2007. Under the 2003 law, large commercial and industrial customers had the option to switch to competitive suppliers and also had a one-time option to return to the POLR for service beginning in 2004, but no customers chose to return to the POLR.

In 2007, legislation was enacted that largely repealed the retail competition provisions of the law. Specifically, the legislation: eliminated the requirement for the implementation of full retail competition; authorized the incumbent utilities to request PSC pre-approval of new generation resource additions, with such resources to be ultimately included in the utility's rate base upon completion; prohibits existing retail choice customers with monthly demand of at least 5,000 KW from returning to the utility, unless the customer can demonstrate that such a supply arrangement will not adversely impact the utility's other customers; requires that all supply arrangements between the utility and its customers be regulated by the PSC; permits existing retail choice customers with monthly demand below 5,000 KW to elect to receive supply from the utility -- those customers that return to the utility would be prohibited from choosing an alternate supplier at a later date; prohibits existing full-service customers with monthly demand below 5,000 KW from switching to an alternate supplier; continues to require the PSC to establish mechanisms through which the utility can recover its supply costs -- the PSC would be permitted to include other utility costs and expenses in such a mechanism, if those costs are found to be in the public interest; and, requires the utility to sequester a minimum of 50% of the carbon dioxide produced by a generation facility until state or federal standards for sequestration are adopted.

Company-Specific Plans--In 1997, in accordance with the then-existing law, NorthWestern Corp. filed a transition plan seeking recovery of certain stranded costs. In 2002, the PSC adopted a settlement setting the net present value of NorthWestern's transition costs at $244.7 million, and authorized recovery of this amount via a surcharge that would be in place through 2029. This surcharge remains in place despite the state's return to a traditional regulatory paradigm. The surcharge is trued-up at the end of each year. (Section updated 6/8/11)

Gas Regulatory Reform/ Industry Restructuring:

Legislation--Since 1997, gas utilities have been permitted to offer open access to transmission, storage, and distribution facilities, and have been allowed to provide customers with the option to choose a natural gas supplier. A local distribution company (LDC) that offers customer choice is required to functionally separate gas production and gathering from transmission, storage, and distribution services, and remove production and gathering investments from rate base. An LDC may apply to the PSC for recovery of transition costs. Upon PSC approval, a utility may finance fixed transition costs with securitization bonds. Gas utilities that have implemented customer choice may acquire gas gathering and production facilities and request PSC approval to include such assets in rate base, as permitted by state law.

Customer Choice--Transportation-only service for large-volume customers has been available for several years, and retail choice for small customers was phased in by 2002. NorthWestern Corp. and MDU Resources (MDU) utilize cost recovery mechanisms to recover gas supply costs incurred to serve default customers.

Stranded Cost Recovery--Under state law, NorthWestern may recover stranded gas production assets and related regulatory assets over a 15-year period. In 1997, the PSC adopted settlements authorizing NorthWestern to implement a surcharge for gas production assets for the recovery of $35.6 million of such costs, and a second surcharge for the recovery of $24.3 million of production-related regulatory assets and conservation investments. Securitization of these costs is permitted, and $62.7 million of such bonds were issued in 1998 (see the Securitization section.) State law effectively precludes MDU from recovering stranded gas-related assets through a surcharge. (Section updated 6/8/11)

Securitization:

In 1998, the PSC approved NorthWestern Corp.'s application to issue up to $65 million of gas retail competition transition bonds. A special purpose entity formed by the company subsequently issued $62.7 million of transition bonds, and the proceeds were used to reduce the company's outstanding debt and equity. State law permitted NorthWestern to request PSC approval to issue electric transition securitization bonds; however, no action to securitize these stranded costs was taken. (Section updated 6/8/11)

Adjustment Clauses:

In accordance with the state's restructuring statutes, NorthWestern Corp. (then Montana Power) sold its generation assets in 1999 and subsequently entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort customers. NorthWestern recovers supply costs through a cost recovery mechanism, adjusted monthly, under which rates are based on estimated loads and electricity costs for the upcoming tracking period. The PSC reviews and adjusts rates for differences between estimates and actual results. NorthWestern is also permitted to recoup revenues lost as a result of demand-side management programs in the context of its annual default supply cost recovery filings.

MDU Resources (MDU) utilizes a monthly-adjusted fuel and purchased power cost adjustment mechanism that contains certain incentive provisions (see the Alternative Regulation section). The mechanism is to terminate on Dec. 31, 2011, unless extended by the PSC.

On Dec. 9, 2010, the PSC authorized NorthWestern to implement a pilot decoupling mechanism for its residential and small general service electric customers in the context of a general rate case. The mechanism excludes revenue variations due to weather. The pilot program is to be in effect for a four-year period. We note that the decoupling mechanism and certain other aspects of the PSC's Dec. 9, 2010 decision are the subject of an appeal pending before the District Court (see the Court Actions section). The parties to the appeal have

reached a settlement that, among other things, calls for the decoupling mechanism to be terminated.

MDU and NorthWestern are permitted to track changes in the cost of purchased gas and other gas costs through separate tariffs. The companies defer, for later recovery or refund, gas expenses that are in excess of, or less than, the costs recovered through current rate levels. MDU Resources' also utilizes a tracking (decoupling) mechanism to recover the costs associated with gas conservation programs, as well as to recoup revenues lost as a result of the programs. This mechanism excludes the effects of weather on revenues. (Section updated 6/8/11)

Integrated Resource Planning:

The state's utilities file resource plans every two years, and generally use a 20-year planning horizon. The filings are largely informational, and PSC approval is not required. We note that the two largest Montana utilities operate under different resource planning frameworks, as NorthWestern Corp. is a restructured utility and MDU Resources is a vertically integrated utility.

Legislation enacted in 2007 largely repealed previously-enacted electric restructuring statutes (see the Electric Regulatory Reform/Industry Restructuring section) and authorized the utilities to seek PSC pre-approval of new generation resource additions, including the ratemaking parameters to apply to the individual projects for the life of the project (see the Return on Equity section).

On March 25, 2011, legislation was enacted requiring the PSC to utilize an avoided-cost approach to establish long-term purchased power contracts between qualifying small power producers and the state's electric utilities. (Section updated 6/8/11)

Renewable Energy:

State law requires Montana's electric utilities to procure at least 15% of their supply from renewable resources by 2015. Beginning in 2008, providers were required to obtain at least 5% of their generation from renewable resources, with the threshold rising to 10% in 2010, and to 15% in 2015. (Section updated 6/8/11)

Jim Davis

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MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-091 RE: Exhibit No.__(JSG-2)
Witness: Stephen Gaske

Please provide all schedules of your Exhibit No.__(JSG-2) in working electronic format with all formulas and links intact, including all additional supporting worksheets that are linked to the exhibits.

Response:

Please see on the enclosed CD the Microsoft Excel file entitled 'MCC-091 Att. A JSG-2.xlsx'.

MONTANA-DAKOTA UTILITIES CO.
MONTANA CONSUMER COUNSEL
DATA REQUEST
DATED NOVEMBER 30, 2012
DOCKET NO. D2012.9.100

MCC-092 RE: Exhibit No.__(JSG-2)
Witness: Stephen Gaske

Please provide hard copies of all supporting documents used in the preparation of the Schedules of Exhibit No.__(JSG-2) as referenced in the footnotes (e.g., data source documents, work papers, etc).

Response:

Please see Attachments A-I on the enclosed CD. Due to the voluminous nature of this response, only one paper copy of Attachments A-G and I are provided to Dr. Wilson. Attachment H is only provided electronically.

Response No. MCC-092
Attachment A

Consumer Price Index - All Urban Consumers
Original Data Value

Series Id: CUUR0000SA0,CUUS0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 1973 to 2011

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	HALF1	HALF2	
1973	42.6	42.9	43.3	43.6	43.9	44.2	44.3	45.1	45.2	45.6	45.9	46.2	44.4			
1974	46.6	47.2	47.8	48.0	48.6	49.0	49.4	50.0	50.6	51.1	51.5	51.9	49.3			11.0%
1975	52.1	52.5	52.7	52.9	53.2	53.6	54.2	54.3	54.6	54.9	55.3	55.5	53.8			9.1%
1976	55.6	55.8	55.9	56.1	56.5	56.8	57.1	57.4	57.6	57.9	58.0	58.2	56.9			5.8%
1977	58.5	59.1	59.5	60.0	60.3	60.7	61.0	61.2	61.4	61.6	61.9	62.1	60.6			6.5%
1978	62.5	62.9	63.4	63.9	64.5	65.2	65.7	66.0	66.5	67.1	67.4	67.7	65.2			7.6%
1979	68.3	69.1	69.8	70.6	71.5	72.3	73.1	73.8	74.6	75.2	75.9	76.7	72.6			11.3%
1980	77.8	78.9	80.1	81.0	81.8	82.7	82.7	83.3	84.0	84.8	85.5	86.3	82.4			13.5%
1981	87.0	87.9	88.5	89.1	89.8	90.6	91.6	92.3	93.2	93.4	93.7	94.0	90.9			10.3%
1982	94.3	94.6	94.5	94.9	95.8	97.0	97.5	97.7	97.9	98.2	98.0	97.6	96.5			6.2%
1983	97.8	97.9	97.9	98.6	99.2	99.5	99.9	100.2	100.7	101.0	101.2	101.3	99.6			3.2%
1984	101.9	102.4	102.6	103.1	103.4	103.7	104.1	104.5	105.0	105.3	105.3	105.3	103.9	102.9	104.9	4.3%
1985	105.5	106.0	106.4	106.9	107.3	107.6	107.8	108.0	108.3	108.7	109.0	109.3	107.6	106.6	108.5	3.6%
1986	109.6	109.3	108.8	108.6	108.9	109.5	109.5	109.7	110.2	110.3	110.4	110.5	109.6	109.1	110.1	1.9%
1987	111.2	111.6	112.1	112.7	113.1	113.5	113.8	114.4	115.0	115.3	115.4	115.4	113.6	112.4	114.9	3.6%
1988	115.7	116.0	116.5	117.1	117.5	118.0	118.5	119.0	119.8	120.2	120.3	120.5	118.3	116.8	119.7	4.1%
1989	121.1	121.6	122.3	123.1	123.8	124.1	124.4	124.6	125.0	125.6	125.9	126.1	124.0	122.7	125.3	4.8%
1990	127.4	128.0	128.7	128.9	129.2	129.9	130.4	131.6	132.7	133.5	133.8	133.8	130.7	128.7	132.6	5.4%
1991	134.6	134.8	135.0	135.2	135.6	136.0	136.2	136.6	137.2	137.4	137.8	137.9	136.2	135.2	137.2	4.2%
1992	138.1	138.6	139.3	139.5	139.7	140.2	140.5	140.9	141.3	141.8	142.0	141.9	140.3	139.2	141.4	3.0%
1993	142.6	143.1	143.6	144.0	144.2	144.4	144.4	144.8	145.1	145.7	145.8	145.8	144.5	143.7	145.3	3.0%
1994	146.2	146.7	147.2	147.4	147.5	148.0	148.4	149.0	149.4	149.5	149.7	149.7	148.2	147.2	149.3	2.6%
1995	150.3	150.9	151.4	151.9	152.2	152.5	152.5	152.9	153.2	153.7	153.6	153.5	152.4	151.5	153.2	2.8%
1996	154.4	154.9	155.7	156.3	156.6	156.7	157.0	157.3	157.8	158.3	158.6	158.6	156.9	155.8	157.9	3.0%
1997	159.1	159.6	160.0	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3	160.5	159.9	161.2	2.3%
1998	161.6	161.9	162.2	162.5	162.8	163.0	163.2	163.4	163.6	164.0	164.0	163.9	163.0	162.3	163.7	1.6%
1999	164.3	164.5	165.0	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6	165.4	167.8	2.2%
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0	172.2	170.8	173.6	3.4%
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7	177.1	176.6	177.5	2.8%
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9	179.9	178.9	180.9	1.6%
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3	184.0	183.3	184.6	2.3%

Bureau of Labor Statistics

2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3	188.9	187.6	190.2	2.7%
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8	195.3	193.2	197.4	3.4%
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8	201.6	200.6	202.6	3.2%
2007	202.416	203.499	205.352	206.686	207.949	208.352	208.299	207.917	208.490	208.936	210.177	210.036	207.342	205.709	208.976	2.8%
2008	211.080	211.693	213.528	214.823	216.632	218.815	219.964	219.086	218.783	216.573	212.425	210.228	215.303	214.429	216.177	3.8%
2009	211.143	212.193	212.709	213.240	213.856	215.693	215.351	215.834	215.969	216.177	216.330	215.949	214.537	213.139	215.935	-0.4%
2010	216.687	216.741	217.631	218.009	218.178	217.965	218.011	218.312	218.439	218.711	218.803	219.179	218.056	217.535	218.576	1.6%
2011	220.223	221.309	223.467	224.906	225.964	225.722	225.922	226.545	226.889	226.421	226.230	225.672	224.939	223.598	226.280	3.2%

Source: Bureau of Labor Statistics

Generated on: December 4, 2012 (01:50:42 PM)

Table 1.1.9. Implicit Price Deflators for Gross Domestic Product

[Index numbers, 2005=100]

Bureau of Economic Analysis

Last Revised on: July 27, 2012 - Next Release Date August 29, 2012

Line		1970	1971	1972	1973	1974	1975	1976
1	**Gross domestic product**	24.338	25.554	26.657	28.136	30.69	33.591	35.519
2	**Personal consumption expenditures**	23.67	24.676	25.52	26.897	29.698	32.179	33.945
3	Goods	35.187	36.245	37.173	39.39	44.306	47.886	49.759
4	Durable goods	56.033	57.968	58.606	59.474	63.379	69.051	72.827
5	Nondurable goods	27.425	28.199	29.103	31.45	36.206	39.004	40.274
6	Services	18.273	19.271	20.089	21.065	22.853	24.82	26.54
7	**Gross private domestic investment**	32.191	33.787	35.201	37.107	40.865	45.839	48.362
8	Fixed investment	31.14	32.708	34.11	35.995	39.54	44.494	47.072
9	Nonresidential	40.531	42.437	43.871	45.56	49.958	56.836	59.988
10	Structures	15.415	16.602	17.796	19.175	21.828	24.443	25.644
11	Equipment and software	60.561	62.36	63.112	64.184	68.917	79.1	83.755
12	Residential	16.666	17.632	18.703	20.359	22.46	24.547	26.124
13	Change in private inventories	---	---	---	---	---	---	---
14	**Net exports of goods and services**	---	---	---	---	---	---	---
15	Exports	34.054	35.31	36.956	41.815	51.517	56.781	58.645
16	Goods	39.186	40.232	41.302	47.937	60.665	67.426	69.15
17	Services	24.165	25.751	28.36	29.68	33.11	35.334	37.468
18	Imports	23.587	25.035	26.789	31.446	44.989	48.733	50.201
19	Goods	24.225	25.467	27.418	32.317	48.36	52.411	53.812
20	Services	20.511	22.368	23.483	27.163	32.303	34.921	36.5
21	**Government consumption expenditures and gross investment**	18.942	20.417	21.986	23.591	25.974	28.581	30.464
22	Federal	19.688	21.371	23.457	25.066	27.299	30.14	32.283
23	National defense	19.116	20.81	23.209	24.911	27.223	29.88	32.058
24	Nondefense	21.107	22.707	23.851	25.188	27.199	30.453	32.494
25	State and local	18.413	19.722	20.898	22.497	24.973	27.412	29.117
	Addendum:							
26	Gross national product	24.32	25.537	26.639	28.121	30.669	33.57	35.502
			5.0%	4.3%	5.5%	9.1%	9.5%	5.7%

6

1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
37.783	40.435	43.798	47.791	52.27	55.459	57.652	59.817	61.628	62.991	64.819	67.046	69.577	72.262
36.155	38.688	42.119	46.642	50.752	53.563	55.868	57.981	59.882	61.341	63.618	66.151	69.025	72.18
52.435	55.653	60.916	67.737	72.77	74.753	76.102	77.541	78.785	78.417	80.939	83.072	86.268	89.801
76.177	80.441	85.773	93.216	99.45	103.329	105.421	106.981	108.112	109.301	112.446	114.301	116.384	117.54
42.582	45.304	50.186	56.344	60.695	62.073	63.138	64.45	65.657	64.818	67.023	69.154	72.584	76.745
28.541	30.759	33.33	36.78	40.444	43.603	46.318	48.729	50.929	53.249	55.409	58.123	60.84	63.808
51.999	56.243	61.341	67.005	73.424	77.16	77.008	77.542	78.33	79.974	81.578	83.421	85.414	86.977
50.767	55.055	60.045	65.663	71.765	75.693	75.574	76.016	76.973	78.813	80.275	82.356	84.35	86.064
64.093	68.386	73.939	80.461	88.229	93.089	92.258	92.035	92.757	94.333	95.181	97.295	99.336	101.238
27.868	30.56	34.11	37.281	42.408	45.755	44.59	44.978	46.046	46.93	47.684	49.709	51.654	53.322
88.731	93.412	99.335	107.819	115.524	120.031	120.284	119.233	119.09	120.976	121.637	123.154	124.695	126.31
28.759	32.281	35.902	39.789	43.036	45.34	46.38	47.713	48.944	50.994	53.079	54.913	56.68	58.011
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---	---	---	---	---	---	---	---	---	---	---	---	---	---
61.034	64.753	72.545	79.904	85.81	86.204	86.544	87.348	84.673	83.406	85.516	89.945	91.443	92.063
71.669	75.801	85.807	94.059	100.697	99.545	98.819	99.678	94.691	91.589	93.956	100.006	101.309	100.348
39.579	42.446	45.749	51.38	55.845	59.232	61.553	62.232	63.928	66.007	67.587	68.937	70.783	74.414
54.624	58.482	68.483	85.301	89.887	86.855	83.601	82.879	80.156	80.154	85.008	89.074	91.021	93.63
58.743	62.66	73.888	93.235	98.425	94.449	90.501	89.878	86.342	84.408	90.427	94.734	97.386	99.175
39.093	42.646	48.16	55.892	58.319	58.36	57.404	56.419	56.35	62.45	63.339	66.424	66.071	71.019
32.578	34.664	37.569	41.663	45.761	48.768	50.709	53.31	54.966	55.969	57.532	59.065	60.915	63.395
34.722	36.866	39.704	43.875	48.137	51.405	53.187	56.325	57.602	57.904	58.608	59.849	61.469	63.512
34.486	36.908	39.853	44.179	48.542	51.953	53.775	57.603	58.696	58.642	59.236	60.326	61.882	63.917
34.933	36.452	39.033	42.833	46.837	49.741	51.413	52.69	54.481	55.82	56.856	58.579	60.394	62.462
31.008	33.045	35.979	40.005	43.979	46.791	48.861	51.038	53.006	54.582	56.854	58.626	60.659	63.479
37.767	40.419	43.782	47.769	52.251	55.438	57.635	59.8	61.614	62.973	64.804	67.031	69.57	72.26
6.4%	7.0%	8.3%	9.1%	9.4%	6.1%	4.0%	3.8%	3.0%	2.2%	2.9%	3.4%	3.8%	3.9%

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
74.824	76.598	78.29	79.94	81.606	83.159	84.628	85.584	86.842	88.723	90.727	92.196	94.135	96.786
74.789	76.989	78.679	80.302	82.078	83.864	85.433	86.246	87.636	89.818	91.53	92.778	94.659	97.121
91.996	93.107	93.915	94.87	95.757	96.809	96.696	95.237	95.735	97.655	97.563	96.563	96.493	97.929
119.263	120.087	121.269	123.642	124.544	123.287	120.593	117.181	114.005	111.953	109.733	106.92	103.113	101.124
78.985	80.133	80.784	81.215	82.063	83.922	84.798	84.169	86.268	90.016	90.961	90.888	92.797	96.114
66.581	69.236	71.294	73.2	75.365	77.473	79.812	81.689	83.509	85.818	88.422	90.801	93.686	96.688
88.293	87.969	89.021	90.205	91.207	90.837	90.455	89.454	89.33	90.276	91.053	91.479	92.489	95.644
87.342	87.09	88.163	89.352	90.393	90.149	89.921	89.085	89.028	90.083	90.888	91.261	92.375	95.543
102.804	101.947	102.1	102.592	102.811	101.612	100.326	98.125	96.704	96.75	96.317	95.889	95.471	96.837
54.287	54.298	56.103	58.089	60.6	62.141	64.516	67.48	69.559	72.298	76.087	79.292	82.174	88.441
128.112	126.605	125.322	124.604	123.163	120.2	116.639	111.454	108.195	106.893	104.364	102.24	100.45	99.9
58.771	59.486	61.89	64.068	66.403	67.827	69.556	71.412	74.151	77.415	80.994	83.002	86.953	93.297
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93.284	92.904	92.879	93.914	96.07	94.799	93.174	91.042	90.477	92.07	91.697	91.322	93.282	96.539
100.243	98.635	98.077	99.125	101.478	98.857	96.127	93.095	91.834	92.999	92.423	91.82	93.616	96.958
78.131	80.13	81.142	82.139	83.872	85.491	86.335	86.285	87.314	89.92	90.042	90.202	92.533	95.598
92.849	92.922	92.21	93.075	95.625	93.958	90.692	85.809	86.311	90.027	87.824	86.846	89.851	94.164
97.3	96.767	95.686	96.383	98.952	96.444	92.46	86.875	86.948	91.205	88.557	87.004	89.541	93.895
73.612	75.673	76.313	77.806	80.235	82.235	82.233	80.628	83.185	84.209	84.219	86.089	91.469	95.573
65.596	67.266	68.938	70.808	72.742	74.477	75.854	76.879	79.337	82.513	84.764	87.003	90.65	94.53
66.032	68.062	69.79	71.683	73.674	75.719	77.047	77.931	79.886	82.524	84.201	87.318	91.024	95.335
66.222	68.522	69.712	71.438	73.161	75.431	76.517	77.328	79.225	81.821	83.484	86.624	90.659	94.895
65.561	66.92	69.883	72.144	74.703	76.276	78.095	79.12	81.188	83.907	85.612	88.689	91.774	96.234
65.448	66.862	68.499	70.357	72.258	73.812	75.219	76.32	79.036	82.482	85.019	86.81	90.425	94.062
74.819	76.586	78.291	79.942	81.611	83.166	84.63	85.581	86.84	88.72	90.725	92.191	94.131	96.782
3.5%	2.4%	2.2%	2.1%	2.1%	1.9%	1.8%	1.1%	1.5%	2.2%	2.3%	1.6%	2.1%	2.8%

2005	2006	2007	2008	2009	2010	2011
100	103.231	106.227	108.582	109.529	110.993	113.359
100	102.723	105.499	108.943	109.004	111.087	113.79
100	101.441	102.764	105.912	103.105	104.852	108.822
100	98.361	96.43	94.628	92.83	91.611	90.799
100	103.23	106.49	112.567	109.177	112.621	119.43
100	103.415	106.981	110.584	112.157	114.418	116.435
100	104.27	106.285	107.621	106.252	104.782	106.362
100	104.347	106.36	107.587	106.318	105.024	106.68
100	103.425	105.645	107.717	107.102	105.514	107.359
100	112.922	119.78	125.706	122.527	121.158	126.85
100	100.049	100.525	101	101.477	99.806	100.445
100	106.081	107.612	106.296	102.713	102.519	103.406
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100	103.441	106.901	111.975	105.924	110.739	117.86
100	103.319	106.793	112.143	104.528	109.828	118.182
100	103.719	107.146	111.574	109.002	112.741	116.972
100	104.131	107.785	119.237	106.598	112.989	121.851
100	104.192	107.792	120.254	105.379	112.52	122.482
100	103.806	107.75	114.006	111.769	114.714	118.126
100	104.842	109.863	115.245	114.592	117.334	121.233
100	104.107	107.753	111.225	110.959	113.583	116.721
100	104.421	108.249	112.187	111.347	113.951	117.411
100	103.468	106.743	109.24	110.177	112.843	115.337
100	105.276	111.112	117.666	116.763	119.579	124.001
100	103.234	106.23	108.589	109.529	110.977	113.353
3.3%	3.2%	2.9%	2.2%	0.9%	1.3%	2.1%

6

Gross Domestic Product
Percent change from preceding period

7/27/12

Annual			Quarterly (Seasonally adjusted annual rates)		
	GDP percent change based on current dollars	GDP percent change based on chained 2005 dollars		GDP percent change based on current dollars	GDP percent change based on chained 2005 dollars
1930	-12.0	-8.6	1947q2	5.6	-0.6
1931	-16.1	-6.5	1947q3	7.0	-0.3
1932	-23.2	-13.1	1947q4	17.1	6.2
1933	-3.9	-1.3	1948q1	9.7	6.5
1934	17.0	10.9	1948q2	11.1	7.5
1935	11.1	8.9	1948q3	10.1	2.2
1936	14.3	13.1	1948q4	1.9	0.6
1937	9.7	5.1	1949q1	-7.3	-5.5
1938	-6.3	-3.4	1949q2	-5.4	-1.4
1939	7.0	8.1	1949q3	2.2	4.6
1940	10.0	8.8	1949q4	-3.6	-3.7
1941	25.0	17.1	1950q1	16.0	17.2
1942	27.7	18.5	1950q2	14.3	12.7
1943	22.7	16.4	1950q3	26.8	16.6
1944	10.7	8.1	1950q4	16.0	7.2
1945	1.5	-1.1	1951q1	21.5	5.1
1946	-0.4	-10.9	1951q2	9.6	6.8
1947	9.8	-0.9	1951q3	8.4	8.2
1948	10.3	4.4	1951q4	5.2	0.7
1949	-0.7	-0.5	1952q1	3.8	4.1
1950	9.9	8.7	1952q2	1.1	0.4
1951	15.5	7.7	1952q3	7.4	2.7
1952	5.6	3.8	1952q4	15.1	13.9
1953	5.9	4.6	1953q1	7.8	7.7
1954	0.3	-0.6	1953q2	3.9	3.1
1955	9.0	7.2	1953q3	-0.9	-2.4
1956	5.5	2.0	1953q4	-5.4	-6.2
1957	5.4	2.0	1954q1	-0.7	-1.9
1958	1.3	-0.9	1954q2	0.8	0.5
1959	8.4	7.2	1954q3	5.2	4.6
1960	3.9	2.5	1954q4	9.4	8.3
1961	3.5	2.3	1955q1	14.2	12.0
1962	7.5	6.1	1955q2	8.5	6.8
1963	5.5	4.4	1955q3	8.6	5.5
1964	7.4	5.8	1955q4	6.4	2.2
1965	8.4	6.4	1956q1	2.2	-1.8
1966	9.5	6.5	1956q2	5.6	3.2
1967	5.7	2.5	1956q3	4.7	-0.5
1968	9.3	4.8	1956q4	8.3	6.7
1969	8.2	3.1	1957q1	8.4	2.5
1970	5.5	0.2	1957q2	1.8	-1.0

1971	8.5	3.4
1972	9.9	5.3
1973	11.7	5.8
1974	8.5	-0.6
1975	9.2	-0.2
1976	11.4	5.4
1977	11.3	4.6
1978	13.0	5.6
1979	11.7	3.1
1980	8.8	-0.3
1981	12.1	2.5
1982	4.0	-1.9
1983	8.7	4.5
1984	11.2	7.2
1985	7.3	4.1
1986	5.8	3.5
1987	6.2	3.2
1988	7.7	4.1
1989	7.5	3.6
1990	5.8	1.9
1991	3.3	-0.2
1992	5.8	3.4
1993	5.1	2.9
1994	6.3	4.1
1995	4.7	2.5
1996	5.7	3.7
1997	6.3	4.5
1998	5.5	4.4
1999	6.4	4.8
2000	6.4	4.1
2001	3.4	1.1
2002	3.5	1.8
2003	4.7	2.5
2004	6.4	3.5
2005	6.5	3.1
2006	6.0	2.7
2007	4.9	1.9
2008	1.9	-0.3
2009	-2.2	-3.1
2010	3.8	2.4
2011	4.0	1.8

1957q3	6.4	3.9
1957q4	-4.1	-4.1
1958q1	-6.4	-10.4
1958q2	3.7	2.5
1958q3	12.5	9.7
1958q4	11.7	9.7
1959q1	8.9	8.3
1959q2	10.9	10.5
1959q3	0.7	-0.5
1959q4	3.1	1.4
1960q1	11.1	9.3
1960q2	-0.6	-1.9
1960q3	2.1	0.7
1960q4	-4.0	-5.0
1961q1	3.3	2.4
1961q2	8.7	7.7
1961q3	8.0	6.6
1961q4	9.9	8.4
1962q1	9.9	7.4
1962q2	5.1	4.5
1962q3	4.7	3.7
1962q4	2.3	1.0
1963q1	6.3	5.3
1963q2	5.9	5.1
1963q3	8.6	7.7
1963q4	6.2	3.1
1964q1	10.6	9.3
1964q2	5.8	4.7
1964q3	7.2	5.5
1964q4	3.1	1.1
1965q1	12.4	10.2
1965q2	7.4	5.5
1965q3	10.0	8.4
1965q4	12.9	10.0
1966q1	13.1	10.2
1966q2	4.8	1.3
1966q3	7.0	2.7
1966q4	7.1	3.3
1967q1	5.5	3.6
1967q2	2.2	0.1
1967q3	7.3	3.2
1967q4	7.7	3.1
1968q1	13.3	8.5
1968q2	11.5	7.0
1968q3	6.9	2.8
1968q4	7.6	1.7
1969q1	11.0	6.5
1969q2	6.5	1.2
1969q3	8.5	2.6
1969q4	3.3	-1.9
1970q1	5.1	-0.6
1970q2	6.4	0.7
1970q3	6.9	3.6
1970q4	0.8	-4.2
1971q1	18.4	11.5
1971q2	7.8	2.3

1971q3	7.5	3.2
1971q4	4.4	1.1
1972q1	14.2	7.3
1972q2	12.4	9.8
1972q3	8.0	3.9
1972q4	12.5	6.8
1973q1	16.0	10.6
1973q2	11.3	4.7
1973q3	5.7	-2.1
1973q4	12.4	3.9
1974q1	4.2	-3.5
1974q2	11.0	1.0
1974q3	8.0	-3.9
1974q4	10.7	-1.6
1975q1	4.4	-4.8
1975q2	9.4	3.1
1975q3	15.1	6.9
1975q4	13.0	5.3
1976q1	14.2	9.4
1976q2	7.5	3.0
1976q3	7.6	2.0
1976q4	10.6	2.9
1977q1	12.0	4.7
1977q2	14.5	8.2
1977q3	12.7	7.4
1977q4	9.0	-0.1
1978q1	7.4	1.4
1978q2	25.5	16.7
1978q3	11.1	4.0
1978q4	14.6	5.4
1979q1	8.1	0.7
1979q2	10.7	0.4
1979q3	12.1	2.9
1979q4	9.5	1.1
1980q1	10.1	1.3
1980q2	0.6	-7.9
1980q3	8.6	-0.7
1980q4	20.0	7.6
1981q1	20.0	8.6
1981q2	4.4	-3.2
1981q3	12.6	4.9
1981q4	2.2	-4.9
1982q1	-1.2	-6.4
1982q2	7.2	2.2
1982q3	4.2	-1.5
1982q4	4.7	0.3
1983q1	8.5	5.1
1983q2	12.5	9.3
1983q3	12.6	8.1
1983q4	11.8	8.5
1984q1	13.6	8.0
1984q2	10.8	7.1
1984q3	7.3	3.9
1984q4	6.0	3.3
1985q1	8.5	3.8
1985q2	5.8	3.4

1985q3	8.2	6.4
1985q4	5.8	3.1
1986q1	6.0	3.9
1986q2	3.8	1.6
1986q3	6.3	3.9
1986q4	4.7	1.9
1987q1	6.1	2.2
1987q2	6.7	4.3
1987q3	6.8	3.5
1987q4	10.3	7.0
1988q1	5.5	2.1
1988q2	9.2	5.2
1988q3	6.8	2.1
1988q4	8.7	5.5
1989q1	8.6	3.8
1989q2	7.1	3.0
1989q3	5.9	3.2
1989q4	3.6	0.9
1990q1	9.4	4.2
1990q2	6.4	1.6
1990q3	3.7	0.0
1990q4	-0.3	-3.5
1991q1	2.4	-1.9
1991q2	5.7	2.7
1991q3	4.9	1.7
1991q4	4.0	1.6
1992q1	6.6	4.5
1992q2	6.9	4.3
1992q3	6.1	4.2
1992q4	6.7	4.3
1993q1	3.2	0.7
1993q2	4.9	2.6
1993q3	4.0	2.1
1993q4	7.7	5.4
1994q1	6.2	4.0
1994q2	7.6	5.6
1994q3	5.1	2.6
1994q4	6.7	4.5
1995q1	3.3	1.0
1995q2	2.7	0.9
1995q3	5.4	3.4
1995q4	4.9	2.8
1996q1	5.2	2.8
1996q2	8.7	7.1
1996q3	4.8	3.5
1996q4	6.8	4.4
1997q1	5.8	3.1
1997q2	7.1	6.1
1997q3	6.6	5.1
1997q4	4.6	3.1
1998q1	4.5	3.8
1998q2	4.6	3.6
1998q3	7.0	5.4
1998q4	8.4	7.1
1999q1	5.5	3.6
1999q2	4.6	3.2

1999q3	6.8	5.2
1999q4	8.9	7.4
2000q1	4.3	1.1
2000q2	10.2	8.0
2000q3	2.8	0.3
2000q4	4.6	2.4
2001q1	1.4	-1.3
2001q2	5.5	2.7
2001q3	0.2	-1.1
2001q4	2.7	1.4
2002q1	4.9	3.5
2002q2	4.0	2.1
2002q3	3.8	2.0
2002q4	2.5	0.1
2003q1	4.5	1.7
2003q2	4.6	3.4
2003q3	9.1	6.7
2003q4	5.8	3.7
2004q1	6.3	2.7
2004q2	6.1	2.6
2004q3	6.0	3.0
2004q4	6.4	3.3
2005q1	8.1	4.2
2005q2	4.5	1.8
2005q3	7.5	3.2
2005q4	5.5	2.1
2006q1	8.3	5.1
2006q2	5.2	1.6
2006q3	3.1	0.1
2006q4	4.6	2.7
2007q1	5.2	0.5
2007q2	6.5	3.6
2007q3	4.3	3.0
2007q4	3.6	1.7
2008q1	0.6	-1.8
2008q2	4.0	1.3
2008q3	-0.6	-3.7
2008q4	-8.4	-8.9
2009q1	-4.4	-5.3
2009q2	-1.1	-0.3
2009q3	1.9	1.4
2009q4	5.3	4.0
2010q1	3.9	2.3
2010q2	4.1	2.2
2010q3	4.6	2.6
2010q4	4.5	2.4
2011q1	2.2	0.1
2011q2	5.2	2.5
2011q3	4.3	1.3
2011q4	4.2	4.1
2012q1	4.2	2.0
2012q2	3.1	1.5

Current-Dollar and "Real" Gross Domestic Product 7/27/12

Annual			Quarterly (Seasonally adjusted annual rates)		
	GDP in billions of current dollars	GDP in billions of chained 2005 dollars		GDP in billions of current dollars	GDP in billions of chained 2005 dollars
1929	103.6	976.1	1947q1	237.2	1,770.7
1930	91.2	892.0	1947q2	240.4	1,768.0
1931	76.5	834.2	1947q3	244.5	1,766.5
1932	58.7	725.2	1947q4	254.3	1,793.3
1933	56.4	715.8	1948q1	260.3	1,821.8
1934	66.0	793.7	1948q2	267.3	1,855.3
1935	73.3	864.2	1948q3	273.8	1,865.3
1936	83.8	977.0	1948q4	275.1	1,868.2
1937	91.9	1,027.1	1949q1	269.9	1,842.2
1938	86.1	991.8	1949q2	266.2	1,835.5
1939	92.2	1,071.9	1949q3	267.6	1,856.1
1940	101.4	1,165.9	1949q4	265.2	1,838.7
1941	126.7	1,365.0	1950q1	275.2	1,913.0
1942	161.9	1,616.8	1950q2	284.5	1,971.2
1943	198.6	1,881.5	1950q3	301.9	2,048.4
1944	219.8	2,033.5	1950q4	313.3	2,084.4
1945	223.0	2,010.7	1951q1	329.0	2,110.7
1946	222.2	1,790.7	1951q2	336.6	2,145.7
1947	244.1	1,774.6	1951q3	343.5	2,188.5
1948	269.1	1,852.7	1951q4	347.9	2,192.2
1949	267.2	1,843.1	1952q1	351.2	2,214.3
1950	293.7	2,004.2	1952q2	352.1	2,216.7
1951	339.3	2,159.3	1952q3	358.5	2,231.6
1952	358.3	2,242.0	1952q4	371.4	2,305.3
1953	379.3	2,345.2	1953q1	378.4	2,348.4
1954	380.4	2,330.4	1953q2	382.0	2,366.2
1955	414.7	2,498.2	1953q3	381.1	2,351.8
1956	437.4	2,547.6	1953q4	375.9	2,314.6
1957	461.1	2,598.8	1954q1	375.2	2,303.5
1958	467.2	2,575.4	1954q2	376.0	2,306.4
1959	506.6	2,760.1	1954q3	380.8	2,332.4
1960	526.4	2,828.5	1954q4	389.4	2,379.1
1961	544.8	2,894.4	1955q1	402.6	2,447.7
1962	585.7	3,069.8	1955q2	410.9	2,488.1
1963	617.8	3,204.0	1955q3	419.4	2,521.4
1964	663.6	3,389.4	1955q4	426.0	2,535.5
1965	719.1	3,607.0	1956q1	428.3	2,523.9
1966	787.7	3,842.1	1956q2	434.2	2,543.8
1967	832.4	3,939.2	1956q3	439.2	2,540.6
1968	909.8	4,129.9	1956q4	448.1	2,582.1
1969	984.4	4,258.2	1957q1	457.2	2,597.9
1970	1,038.3	4,266.3	1957q2	459.2	2,591.7
1971	1,126.8	4,409.5	1957q3	466.4	2,616.6
1972	1,237.9	4,643.8	1957q4	461.5	2,589.1
1973	1,382.3	4,912.8	1958q1	453.9	2,519.0

1974	1,499.5	4,885.7
1975	1,637.7	4,875.4
1976	1,824.6	5,136.9
1977	2,030.1	5,373.1
1978	2,293.8	5,672.8
1979	2,562.2	5,850.1
1980	2,788.1	5,834.0
1981	3,126.8	5,982.1
1982	3,253.2	5,865.9
1983	3,534.6	6,130.9
1984	3,930.9	6,571.5
1985	4,217.5	6,843.4
1986	4,460.1	7,080.5
1987	4,736.4	7,307.0
1988	5,100.4	7,607.4
1989	5,482.1	7,879.2
1990	5,800.5	8,027.1
1991	5,992.1	8,008.3
1992	6,342.3	8,280.0
1993	6,667.4	8,516.2
1994	7,085.2	8,863.1
1995	7,414.7	9,086.0
1996	7,838.5	9,425.8
1997	8,332.4	9,845.9
1998	8,793.5	10,274.7
1999	9,353.5	10,770.7
2000	9,951.5	11,216.4
2001	10,286.2	11,337.5
2002	10,642.3	11,543.1
2003	11,142.2	11,836.4
2004	11,853.3	12,246.9
2005	12,623.0	12,623.0
2006	13,377.2	12,958.5
2007	14,028.7	13,206.4
2008	14,291.5	13,161.9
2009	13,973.7	12,757.9
2010	14,498.9	13,063.0
2011	15,075.7	13,299.1

1958q2	458.0	2,534.5
1958q3	471.7	2,593.9
1958q4	485.0	2,654.3
1959q1	495.5	2,708.0
1959q2	508.5	2,776.4
1959q3	509.3	2,773.1
1959q4	513.2	2,782.8
1960q1	527.0	2,845.3
1960q2	526.2	2,832.0
1960q3	529.0	2,836.6
1960q4	523.7	2,800.2
1961q1	528.0	2,816.9
1961q2	539.0	2,869.6
1961q3	549.5	2,915.9
1961q4	562.6	2,975.3
1962q1	576.1	3,028.7
1962q2	583.2	3,062.1
1962q3	590.0	3,090.4
1962q4	593.3	3,097.9
1963q1	602.5	3,138.4
1963q2	611.2	3,177.7
1963q3	623.9	3,237.6
1963q4	633.5	3,262.2
1964q1	649.6	3,335.4
1964q2	658.9	3,373.7
1964q3	670.5	3,419.5
1964q4	675.6	3,429.0
1965q1	695.7	3,513.3
1965q2	708.1	3,560.9
1965q3	725.2	3,633.2
1965q4	747.5	3,720.8
1966q1	770.8	3,812.2
1966q2	779.9	3,824.9
1966q3	793.1	3,850.0
1966q4	806.9	3,881.2
1967q1	817.8	3,915.4
1967q2	822.3	3,916.2
1967q3	837.0	3,947.5
1967q4	852.7	3,977.6
1968q1	879.8	4,059.5
1968q2	904.1	4,128.5
1968q3	919.3	4,156.7
1968q4	936.2	4,174.7
1969q1	960.9	4,240.5
1969q2	976.1	4,252.8
1969q3	996.3	4,279.7
1969q4	1,004.5	4,259.6
1970q1	1,017.1	4,252.9
1970q2	1,033.1	4,260.7
1970q3	1,050.5	4,298.6
1970q4	1,052.7	4,253.0
1971q1	1,098.1	4,370.3
1971q2	1,118.8	4,395.1
1971q3	1,139.1	4,430.2
1971q4	1,151.4	4,442.5
1972q1	1,190.1	4,521.9
1972q2	1,225.6	4,629.1

1972q3	1,249.3	4,673.5
1972q4	1,286.6	4,750.5
1973q1	1,335.1	4,872.0
1973q2	1,371.5	4,928.4
1973q3	1,390.7	4,902.1
1973q4	1,431.8	4,948.8
1974q1	1,446.5	4,905.4
1974q2	1,484.8	4,918.0
1974q3	1,513.7	4,869.4
1974q4	1,552.8	4,850.2
1975q1	1,569.4	4,791.2
1975q2	1,605.0	4,827.8
1975q3	1,662.4	4,909.1
1975q4	1,713.9	4,973.3
1976q1	1,771.9	5,086.3
1976q2	1,804.2	5,124.6
1976q3	1,837.7	5,149.7
1976q4	1,884.5	5,187.1
1977q1	1,938.5	5,247.3
1977q2	2,005.2	5,351.6
1977q3	2,066.0	5,447.3
1977q4	2,110.8	5,446.1
1978q1	2,149.1	5,464.7
1978q2	2,274.7	5,679.7
1978q3	2,335.2	5,735.4
1978q4	2,416.0	5,811.3
1979q1	2,463.3	5,821.0
1979q2	2,526.4	5,826.4
1979q3	2,599.7	5,868.3
1979q4	2,659.4	5,884.5
1980q1	2,724.1	5,903.4
1980q2	2,728.0	5,782.4
1980q3	2,785.2	5,771.7
1980q4	2,915.3	5,878.4
1981q1	3,051.4	6,000.6
1981q2	3,084.3	5,952.7
1981q3	3,177.0	6,025.0
1981q4	3,194.7	5,950.0
1982q1	3,184.9	5,852.3
1982q2	3,240.9	5,884.0
1982q3	3,274.4	5,861.4
1982q4	3,312.5	5,866.0
1983q1	3,381.0	5,938.9
1983q2	3,482.2	6,072.4
1983q3	3,587.1	6,192.2
1983q4	3,688.1	6,320.2
1984q1	3,807.4	6,442.8
1984q2	3,906.3	6,554.0
1984q3	3,976.0	6,617.7
1984q4	4,034.0	6,671.6
1985q1	4,117.2	6,734.5
1985q2	4,175.7	6,791.5
1985q3	4,258.3	6,897.6
1985q4	4,318.7	6,950.0
1986q1	4,382.4	7,016.8
1986q2	4,423.2	7,045.0
1986q3	4,491.3	7,112.9

1986q4	4,543.3	7,147.3
1987q1	4,611.1	7,186.9
1987q2	4,686.7	7,263.3
1987q3	4,764.5	7,326.3
1987q4	4,883.1	7,451.7
1988q1	4,948.6	7,490.2
1988q2	5,059.3	7,586.4
1988q3	5,142.8	7,625.6
1988q4	5,251.0	7,727.4
1989q1	5,360.3	7,799.9
1989q2	5,453.6	7,858.3
1989q3	5,532.9	7,920.6
1989q4	5,581.7	7,937.9
1990q1	5,708.1	8,020.8
1990q2	5,797.4	8,052.7
1990q3	5,850.6	8,052.6
1990q4	5,846.0	7,982.0
1991q1	5,880.2	7,943.4
1991q2	5,962.0	7,997.0
1991q3	6,033.7	8,030.7
1991q4	6,092.5	8,062.2
1992q1	6,190.7	8,150.7
1992q2	6,295.2	8,237.3
1992q3	6,389.7	8,322.3
1992q4	6,493.6	8,409.8
1993q1	6,544.5	8,425.3
1993q2	6,622.7	8,479.2
1993q3	6,688.3	8,523.8
1993q4	6,813.8	8,636.4
1994q1	6,916.3	8,720.5
1994q2	7,044.3	8,839.8
1994q3	7,131.8	8,896.7
1994q4	7,248.2	8,995.5
1995q1	7,307.7	9,017.6
1995q2	7,355.8	9,037.0
1995q3	7,452.5	9,112.9
1995q4	7,542.5	9,176.4
1996q1	7,638.2	9,239.3
1996q2	7,800.0	9,399.0
1996q3	7,892.7	9,480.8
1996q4	8,023.0	9,584.3
1997q1	8,137.0	9,658.0
1997q2	8,276.8	9,801.2
1997q3	8,409.9	9,924.2
1997q4	8,505.7	10,000.3
1998q1	8,600.6	10,094.8
1998q2	8,698.6	10,185.6
1998q3	8,847.2	10,320.0
1998q4	9,027.5	10,498.6
1999q1	9,148.6	10,592.1
1999q2	9,252.6	10,674.9
1999q3	9,405.1	10,810.7
1999q4	9,607.7	11,004.8
2000q1	9,709.5	11,033.6
2000q2	9,949.1	11,248.8
2000q3	10,017.5	11,258.3
2000q4	10,129.8	11,325.0

2001q1	10,165.1	11,287.8
2001q2	10,301.3	11,361.7
2001q3	10,305.2	11,330.4
2001q4	10,373.1	11,370.0
2002q1	10,498.7	11,467.1
2002q2	10,601.9	11,528.1
2002q3	10,701.7	11,586.6
2002q4	10,766.9	11,590.6
2003q1	10,887.4	11,638.9
2003q2	11,011.6	11,737.5
2003q3	11,255.1	11,930.7
2003q4	11,414.8	12,038.6
2004q1	11,589.9	12,117.9
2004q2	11,762.9	12,195.9
2004q3	11,936.3	12,286.7
2004q4	12,123.9	12,387.2
2005q1	12,361.8	12,515.0
2005q2	12,500.0	12,570.7
2005q3	12,728.6	12,670.5
2005q4	12,901.4	12,735.6
2006q1	13,161.4	12,896.4
2006q2	13,330.4	12,948.7
2006q3	13,432.8	12,950.4
2006q4	13,584.2	13,038.4
2007q1	13,758.5	13,056.1
2007q2	13,976.8	13,173.6
2007q3	14,126.2	13,269.8
2007q4	14,253.2	13,326.0
2008q1	14,273.9	13,266.8
2008q2	14,415.5	13,310.5
2008q3	14,395.1	13,186.9
2008q4	14,081.7	12,883.5
2009q1	13,923.4	12,711.0
2009q2	13,885.4	12,701.0
2009q3	13,952.2	12,746.7
2009q4	14,133.6	12,873.1
2010q1	14,270.3	12,947.6
2010q2	14,413.5	13,019.6
2010q3	14,576.0	13,103.5
2010q4	14,735.9	13,181.2
2011q1	14,814.9	13,183.8
2011q2	15,003.6	13,264.7
2011q3	15,163.2	13,306.9
2011q4	15,321.0	13,441.0
2012q1	15,478.3	13,506.4
2012q2	15,595.9	13,558.0

		30-Year T-Bonds				Average Corporate				Public Utility Bonds (A-Rated)			
		Date	Yield			Date	Yield			Date	Yield		
1	2007	1/1/2007	4.8096	1	2007	1/2/2007	5.88	1	2007	1/2/2007	5.92	1	2007
1	2007	1/2/2007	4.7847	1	2007	1/3/2007	5.85	1	2007	1/3/2007	5.88	1	2007
1	2007	1/3/2007	4.7631	1	2007	1/4/2007	5.81	1	2007	1/4/2007	5.84	1	2007
1	2007	1/4/2007	4.7079	1	2007	1/5/2007	5.82	1	2007	1/5/2007	5.85	1	2007
1	2007	1/5/2007	4.7385	1	2007	1/8/2007	5.82	1	2007	1/8/2007	5.85	1	2007
1	2007	1/8/2007	4.7334	1	2007	1/9/2007	5.82	1	2007	1/9/2007	5.85	1	2007
1	2007	1/9/2007	4.7375	1	2007	1/10/2007	5.85	1	2007	1/10/2007	5.88	1	2007
1	2007	1/10/2007	4.7745	1	2007	1/11/2007	5.9	1	2007	1/11/2007	5.93	1	2007
1	2007	1/11/2007	4.8181	1	2007	1/12/2007	5.94	1	2007	1/12/2007	5.97	1	2007
1	2007	1/12/2007	4.86	1	2007	1/16/2007	5.92	1	2007	1/16/2007	5.95	1	2007
1	2007	1/15/2007	4.86	1	2007	1/17/2007	5.96	1	2007	1/17/2007	5.99	1	2007
1	2007	1/16/2007	4.8401	1	2007	1/18/2007	5.92	1	2007	1/18/2007	5.95	1	2007
1	2007	1/17/2007	4.8706	1	2007	1/19/2007	5.93	1	2007	1/19/2007	5.97	1	2007
1	2007	1/18/2007	4.8401	1	2007	1/22/2007	5.92	1	2007	1/22/2007	5.95	1	2007
1	2007	1/19/2007	4.8623	1	2007	1/23/2007	5.97	1	2007	1/23/2007	6	1	2007
1	2007	1/22/2007	4.8476	1	2007	1/24/2007	5.97	1	2007	1/24/2007	6.01	1	2007
1	2007	1/23/2007	4.9057	1	2007	1/25/2007	6.02	1	2007	1/25/2007	6.05	1	2007
1	2007	1/24/2007	4.9099	1	2007	1/26/2007	6.04	1	2007	1/26/2007	6.07	1	2007
1	2007	1/25/2007	4.9667	1	2007	1/29/2007	6.05	1	2007	1/29/2007	6.08	1	2007
1	2007	1/26/2007	4.9722	1	2007	1/30/2007	6.04	1	2007	1/30/2007	6.06	1	2007
1	2007	1/29/2007	4.995	1	2007	1/31/2007	5.99	1	2007	1/31/2007	6.01	1	2007
1	2007	1/30/2007	4.9777	2	2007	2/1/2007	6	2	2007	2/1/2007	6.02	2	2007
1	2007	1/31/2007	4.9069	2	2007	2/2/2007	5.99	2	2007	2/2/2007	6.01	2	2007
2	2007	2/1/2007	4.9294	2	2007	2/5/2007	5.97	2	2007	2/5/2007	5.98	2	2007
2	2007	2/2/2007	4.922	2	2007	2/6/2007	5.92	2	2007	2/6/2007	5.94	2	2007
2	2007	2/5/2007	4.9071	2	2007	2/7/2007	5.9	2	2007	2/7/2007	5.92	2	2007
2	2007	2/6/2007	4.8679	2	2007	2/8/2007	5.89	2	2007	2/8/2007	5.91	2	2007
2	2007	2/7/2007	4.8521	2	2007	2/9/2007	5.94	2	2007	2/9/2007	5.96	2	2007
2	2007	2/8/2007	4.8396	2	2007	2/12/2007	5.95	2	2007	2/12/2007	5.97	2	2007
2	2007	2/9/2007	4.8635	2	2007	2/13/2007	5.97	2	2007	2/13/2007	5.99	2	2007
2	2007	2/12/2007	4.8857	2	2007	2/14/2007	5.89	2	2007	2/14/2007	5.91	2	2007
2	2007	2/13/2007	4.8989	2	2007	2/15/2007	5.87	2	2007	2/15/2007	5.89	2	2007
2	2007	2/14/2007	4.8333	2	2007	2/16/2007	5.85	2	2007	2/16/2007	5.87	2	2007
2	2007	2/15/2007	4.8054	2	2007	2/20/2007	5.84	2	2007	2/20/2007	5.86	2	2007
2	2007	2/16/2007	4.7875	2	2007	2/21/2007	5.85	2	2007	2/21/2007	5.87	2	2007
2	2007	2/19/2007	4.7874	2	2007	2/22/2007	5.88	2	2007	2/22/2007	5.9	2	2007
2	2007	2/20/2007	4.7765	2	2007	2/23/2007	5.83	2	2007	2/23/2007	5.85	2	2007
2	2007	2/21/2007	4.7904	2	2007	2/26/2007	5.78	2	2007	2/26/2007	5.8	2	2007
2	2007	2/22/2007	4.8293	2	2007	2/27/2007	5.69	2	2007	2/27/2007	5.7	2	2007
2	2007	2/23/2007	4.7765	2	2007	2/28/2007	5.76	2	2007	2/28/2007	5.78	2	2007

2	2007	2/26/2007	4.7303	3	2007	3/1/2007	5.77	3	2007	3/1/2007	5.8	3	2007
2	2007	2/27/2007	4.6316	3	2007	3/2/2007	5.75	3	2007	3/2/2007	5.77	3	2007
2	2007	2/28/2007	4.6806	3	2007	3/5/2007	5.77	3	2007	3/5/2007	5.79	3	2007
3	2007	3/1/2007	4.6758	3	2007	3/6/2007	5.77	3	2007	3/6/2007	5.79	3	2007
3	2007	3/2/2007	4.6382	3	2007	3/7/2007	5.75	3	2007	3/7/2007	5.77	3	2007
3	2007	3/5/2007	4.6344	3	2007	3/8/2007	5.76	3	2007	3/8/2007	5.78	3	2007
3	2007	3/6/2007	4.6584	3	2007	3/9/2007	5.83	3	2007	3/9/2007	5.85	3	2007
3	2007	3/7/2007	4.6286	3	2007	3/12/2007	5.8	3	2007	3/12/2007	5.81	3	2007
3	2007	3/8/2007	4.6545	3	2007	3/13/2007	5.77	3	2007	3/13/2007	5.79	3	2007
3	2007	3/9/2007	4.7214	3	2007	3/14/2007	5.81	3	2007	3/14/2007	5.82	3	2007
3	2007	3/12/2007	4.697	3	2007	3/15/2007	5.81	3	2007	3/15/2007	5.82	3	2007
3	2007	3/13/2007	4.6564	3	2007	3/16/2007	5.82	3	2007	3/16/2007	5.82	3	2007
3	2007	3/14/2007	4.6989	3	2007	3/19/2007	5.84	3	2007	3/19/2007	5.85	3	2007
3	2007	3/15/2007	4.695	3	2007	3/20/2007	5.83	3	2007	3/20/2007	5.83	3	2007
3	2007	3/16/2007	4.6931	3	2007	3/21/2007	5.82	3	2007	3/21/2007	5.82	3	2007
3	2007	3/19/2007	4.7135	3	2007	3/22/2007	5.91	3	2007	3/22/2007	5.91	3	2007
3	2007	3/20/2007	4.7115	3	2007	3/23/2007	5.92	3	2007	3/23/2007	5.93	3	2007
3	2007	3/21/2007	4.7203	3	2007	3/26/2007	5.91	3	2007	3/26/2007	5.91	3	2007
3	2007	3/22/2007	4.7744	3	2007	3/27/2007	5.94	3	2007	3/27/2007	5.94	3	2007
3	2007	3/23/2007	4.8022	3	2007	3/28/2007	5.96	3	2007	3/28/2007	5.96	3	2007
3	2007	3/26/2007	4.8002	3	2007	3/29/2007	5.96	3	2007	3/29/2007	5.95	3	2007
3	2007	3/27/2007	4.7982	3	2007	3/30/2007	5.98	3	2007	3/30/2007	5.97	3	2007
3	2007	3/28/2007	4.8311	4	2007	4/2/2007	5.97	4	2007	4/2/2007	5.95	4	2007
3	2007	3/29/2007	4.8432	4	2007	4/3/2007	5.98	4	2007	4/3/2007	5.96	4	2007
3	2007	3/30/2007	4.8432	4	2007	4/4/2007	5.98	4	2007	4/4/2007	5.96	4	2007
4	2007	4/2/2007	4.8361	4	2007	4/5/2007	6.01	4	2007	4/5/2007	5.99	4	2007
4	2007	4/3/2007	4.8482	4	2007	4/6/2007	6.06	4	2007	4/6/2007	6.04	4	2007
4	2007	4/4/2007	4.8422	4	2007	4/9/2007	6.06	4	2007	4/9/2007	6.03	4	2007
4	2007	4/5/2007	4.8745	4	2007	4/10/2007	6.04	4	2007	4/10/2007	6.02	4	2007
4	2007	4/6/2007	4.9203	4	2007	4/11/2007	6.04	4	2007	4/11/2007	6.02	4	2007
4	2007	4/9/2007	4.9183	4	2007	4/12/2007	6.04	4	2007	4/12/2007	6.02	4	2007
4	2007	4/10/2007	4.904	4	2007	4/13/2007	6.05	4	2007	4/13/2007	6.03	4	2007
4	2007	4/11/2007	4.908	4	2007	4/16/2007	6.01	4	2007	4/16/2007	6	4	2007
4	2007	4/12/2007	4.907	4	2007	4/17/2007	5.96	4	2007	4/17/2007	5.95	4	2007
4	2007	4/13/2007	4.9296	4	2007	4/18/2007	5.93	4	2007	4/18/2007	5.92	4	2007
4	2007	4/16/2007	4.8897	4	2007	4/19/2007	5.95	4	2007	4/19/2007	5.94	4	2007
4	2007	4/17/2007	4.8432	4	2007	4/20/2007	5.96	4	2007	4/20/2007	5.94	4	2007
4	2007	4/18/2007	4.8151	4	2007	4/23/2007	5.94	4	2007	4/23/2007	5.93	4	2007
4	2007	4/19/2007	4.8331	4	2007	4/24/2007	5.91	4	2007	4/24/2007	5.9	4	2007
4	2007	4/20/2007	4.8452	4	2007	4/25/2007	5.94	4	2007	4/25/2007	5.92	4	2007
4	2007	4/23/2007	4.8221	4	2007	4/26/2007	5.98	4	2007	4/26/2007	5.96	4	2007
4	2007	4/24/2007	4.8061	4	2007	4/27/2007	5.99	4	2007	4/27/2007	5.97	4	2007

4	2007	4/25/2007	4.8331	4	2007	4/30/2007	5.92	4	2007	4/30/2007	5.9	4	2007
4	2007	4/26/2007	4.8806	5	2007	5/1/2007	5.92	5	2007	5/1/2007	5.9	5	2007
4	2007	4/27/2007	4.8806	5	2007	5/2/2007	5.92	5	2007	5/2/2007	5.9	5	2007
4	2007	4/30/2007	4.8131	5	2007	5/3/2007	5.94	5	2007	5/3/2007	5.92	5	2007
5	2007	5/1/2007	4.8151	5	2007	5/4/2007	5.9	5	2007	5/4/2007	5.88	5	2007
5	2007	5/2/2007	4.8151	5	2007	5/7/2007	5.9	5	2007	5/7/2007	5.87	5	2007
5	2007	5/3/2007	4.8382	5	2007	5/8/2007	5.91	5	2007	5/8/2007	5.88	5	2007
5	2007	5/4/2007	4.8051	5	2007	5/9/2007	5.94	5	2007	5/9/2007	5.92	5	2007
5	2007	5/7/2007	4.7822	5	2007	5/10/2007	5.93	5	2007	5/10/2007	5.91	5	2007
5	2007	5/8/2007	4.8021	5	2007	5/11/2007	5.95	5	2007	5/11/2007	5.93	5	2007
5	2007	5/9/2007	4.8362	5	2007	5/14/2007	5.96	5	2007	5/14/2007	5.94	5	2007
5	2007	5/10/2007	4.8221	5	2007	5/15/2007	5.99	5	2007	5/15/2007	5.97	5	2007
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1	2008	1/2/2008	4.3524	1	2008	1/17/2008	5.96	1	2008	1/17/2008	5.94	1	2008
1	2008	1/3/2008	4.3638	1	2008	1/18/2008	6	1	2008	1/18/2008	5.99	1	2008
1	2008	1/4/2008	4.3761	1	2008	1/22/2008	5.98	1	2008	1/22/2008	5.96	1	2008
1	2008	1/7/2008	4.3382	1	2008	1/23/2008	5.94	1	2008	1/23/2008	5.92	1	2008
1	2008	1/8/2008	4.3101	1	2008	1/24/2008	6.11	1	2008	1/24/2008	6.09	1	2008
1	2008	1/9/2008	4.3407	1	2008	1/25/2008	6.03	1	2008	1/25/2008	6.01	1	2008
1	2008	1/10/2008	4.4502	1	2008	1/28/2008	6.03	1	2008	1/28/2008	6.01	1	2008
1	2008	1/11/2008	4.375	1	2008	1/29/2008	6.08	1	2008	1/29/2008	6.07	1	2008
1	2008	1/14/2008	4.3582	1	2008	1/30/2008	6.17	1	2008	1/30/2008	6.16	1	2008
1	2008	1/15/2008	4.2725	1	2008	1/31/2008	6.08	1	2008	1/31/2008	6.07	1	2008
1	2008	1/16/2008	4.3423	2	2008	2/1/2008	6.05	2	2008	2/1/2008	6.04	2	2008
1	2008	1/17/2008	4.2551	2	2008	2/4/2008	6.1	2	2008	2/4/2008	6.1	2	2008
1	2008	1/18/2008	4.281	2	2008	2/5/2008	6.06	2	2008	2/5/2008	6.05	2	2008
1	2008	1/21/2008	4.2809	2	2008	2/6/2008	6.1	2	2008	2/6/2008	6.08	2	2008
1	2008	1/22/2008	4.1942	2	2008	2/7/2008	6.22	2	2008	2/7/2008	6.21	2	2008
1	2008	1/23/2008	4.314	2	2008	2/8/2008	6.16	2	2008	2/8/2008	6.15	2	2008
1	2008	1/24/2008	4.3925	2	2008	2/11/2008	6.14	2	2008	2/11/2008	6.11	2	2008
1	2008	1/25/2008	4.2634	2	2008	2/12/2008	6.2	2	2008	2/12/2008	6.17	2	2008
1	2008	1/28/2008	4.2781	2	2008	2/13/2008	6.23	2	2008	2/13/2008	6.21	2	2008
1	2008	1/29/2008	4.3551	2	2008	2/14/2008	6.37	2	2008	2/14/2008	6.35	2	2008
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1	2008	1/31/2008	4.3225	2	2008	2/19/2008	6.37	2	2008	2/19/2008	6.35	2	2008
2	2008	2/1/2008	4.3084	2	2008	2/20/2008	6.37	2	2008	2/20/2008	6.34	2	2008
2	2008	2/4/2008	4.3779	2	2008	2/21/2008	6.27	2	2008	2/21/2008	6.24	2	2008
2	2008	2/5/2008	4.3258	2	2008	2/22/2008	6.31	2	2008	2/22/2008	6.27	2	2008
2	2008	2/6/2008	4.3549	2	2008	2/25/2008	6.39	2	2008	2/25/2008	6.35	2	2008
2	2008	2/7/2008	4.5177	2	2008	2/26/2008	6.38	2	2008	2/26/2008	6.34	2	2008
2	2008	2/8/2008	4.4166	2	2008	2/27/2008	6.36	2	2008	2/27/2008	6.32	2	2008
2	2008	2/11/2008	4.3986	2	2008	2/28/2008	6.27	2	2008	2/28/2008	6.22	2	2008
2	2008	2/12/2008	4.4576	2	2008	2/29/2008	6.14	2	2008	2/29/2008	6.09	2	2008

2	2008	2/13/2008	4.537	3	2008	3/3/2008	6.15	3	2008	3/3/2008	6.1	3	2008
2	2008	2/14/2008	4.6368	3	2008	3/4/2008	6.21	3	2008	3/4/2008	6.16	3	2008
2	2008	2/15/2008	4.5762	3	2008	3/5/2008	6.34	3	2008	3/5/2008	6.29	3	2008
2	2008	2/18/2008	4.5762	3	2008	3/6/2008	6.35	3	2008	3/6/2008	6.3	3	2008
2	2008	2/19/2008	4.6649	3	2008	3/7/2008	6.32	3	2008	3/7/2008	6.28	3	2008
2	2008	2/20/2008	4.6079	3	2008	3/10/2008	6.25	3	2008	3/10/2008	6.22	3	2008
2	2008	2/21/2008	4.5438	3	2008	3/11/2008	6.35	3	2008	3/11/2008	6.32	3	2008
2	2008	2/22/2008	4.5733	3	2008	3/12/2008	6.22	3	2008	3/12/2008	6.19	3	2008
2	2008	2/25/2008	4.6549	3	2008	3/13/2008	6.28	3	2008	3/13/2008	6.24	3	2008
2	2008	2/26/2008	4.6559	3	2008	3/14/2008	6.2	3	2008	3/14/2008	6.17	3	2008
2	2008	2/27/2008	4.6499	3	2008	3/17/2008	6.17	3	2008	3/17/2008	6.15	3	2008
2	2008	2/28/2008	4.5213	3	2008	3/18/2008	6.21	3	2008	3/18/2008	6.18	3	2008
2	2008	2/29/2008	4.4023	3	2008	3/19/2008	6.14	3	2008	3/19/2008	6.11	3	2008
3	2008	3/3/2008	4.4327	3	2008	3/20/2008	6.08	3	2008	3/20/2008	6.07	3	2008
3	2008	3/4/2008	4.5068	3	2008	3/24/2008	6.21	3	2008	3/24/2008	6.2	3	2008
3	2008	3/5/2008	4.598	3	2008	3/25/2008	6.22	3	2008	3/25/2008	6.21	3	2008
3	2008	3/6/2008	4.5605	3	2008	3/26/2008	6.24	3	2008	3/26/2008	6.25	3	2008
3	2008	3/7/2008	4.5399	3	2008	3/27/2008	6.29	3	2008	3/27/2008	6.29	3	2008
3	2008	3/10/2008	4.4633	3	2008	3/28/2008	6.25	3	2008	3/28/2008	6.25	3	2008
3	2008	3/11/2008	4.5077	3	2008	3/31/2008	6.21	3	2008	3/31/2008	6.2	3	2008
3	2008	3/12/2008	4.4098	4	2008	4/1/2008	6.31	4	2008	4/1/2008	6.29	4	2008
3	2008	3/13/2008	4.447	4	2008	4/2/2008	6.31	4	2008	4/2/2008	6.31	4	2008
3	2008	3/14/2008	4.3635	4	2008	4/3/2008	6.3	4	2008	4/3/2008	6.31	4	2008
3	2008	3/17/2008	4.2854	4	2008	4/4/2008	6.22	4	2008	4/4/2008	6.23	4	2008
3	2008	3/18/2008	4.3485	4	2008	4/7/2008	6.26	4	2008	4/7/2008	6.28	4	2008
3	2008	3/19/2008	4.2104	4	2008	4/8/2008	6.28	4	2008	4/8/2008	6.29	4	2008
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3	2008	3/21/2008	4.1599	4	2008	4/10/2008	6.22	4	2008	4/10/2008	6.24	4	2008
3	2008	3/24/2008	4.3644	4	2008	4/11/2008	6.18	4	2008	4/11/2008	6.2	4	2008
3	2008	3/25/2008	4.3028	4	2008	4/14/2008	6.23	4	2008	4/14/2008	6.24	4	2008
3	2008	3/26/2008	4.3065	4	2008	4/15/2008	6.28	4	2008	4/15/2008	6.3	4	2008
3	2008	3/27/2008	4.3898	4	2008	4/16/2008	6.41	4	2008	4/16/2008	6.41	4	2008
3	2008	3/28/2008	4.3177	4	2008	4/17/2008	6.4	4	2008	4/17/2008	6.4	4	2008
3	2008	3/31/2008	4.2917	4	2008	4/18/2008	6.34	4	2008	4/18/2008	6.32	4	2008
4	2008	4/1/2008	4.3993	4	2008	4/21/2008	6.29	4	2008	4/21/2008	6.27	4	2008
4	2008	4/2/2008	4.405	4	2008	4/22/2008	6.27	4	2008	4/22/2008	6.27	4	2008
4	2008	4/3/2008	4.3785	4	2008	4/23/2008	6.28	4	2008	4/23/2008	6.28	4	2008
4	2008	4/4/2008	4.3055	4	2008	4/24/2008	6.34	4	2008	4/24/2008	6.34	4	2008
4	2008	4/7/2008	4.3447	4	2008	4/25/2008	6.38	4	2008	4/25/2008	6.38	4	2008
4	2008	4/8/2008	4.3794	4	2008	4/28/2008	6.33	4	2008	4/28/2008	6.3	4	2008
4	2008	4/9/2008	4.3204	4	2008	4/29/2008	6.31	4	2008	4/29/2008	6.29	4	2008
4	2008	4/10/2008	4.3484	4	2008	4/30/2008	6.23	4	2008	4/30/2008	6.22	4	2008

4	2008	4/11/2008	4.299	5	2008	5/1/2008	6.2	5	2008	5/1/2008	6.19	5	2008
4	2008	4/14/2008	4.3493	5	2008	5/2/2008	6.25	5	2008	5/2/2008	6.24	5	2008
4	2008	4/15/2008	4.4412	5	2008	5/5/2008	6.27	5	2008	5/5/2008	6.26	5	2008
4	2008	4/16/2008	4.4932	5	2008	5/6/2008	6.33	5	2008	5/6/2008	6.32	5	2008
4	2008	4/17/2008	4.5263	5	2008	5/7/2008	6.31	5	2008	5/7/2008	6.3	5	2008
4	2008	4/18/2008	4.4961	5	2008	5/8/2008	6.26	5	2008	5/8/2008	6.24	5	2008
4	2008	4/21/2008	4.4884	5	2008	5/9/2008	6.22	5	2008	5/9/2008	6.2	5	2008
4	2008	4/22/2008	4.4441	5	2008	5/12/2008	6.22	5	2008	5/12/2008	6.2	5	2008
4	2008	4/23/2008	4.4913	5	2008	5/13/2008	6.33	5	2008	5/13/2008	6.3	5	2008
4	2008	4/24/2008	4.5459	5	2008	5/14/2008	6.36	5	2008	5/14/2008	6.32	5	2008
4	2008	4/25/2008	4.5914	5	2008	5/15/2008	6.29	5	2008	5/15/2008	6.26	5	2008
4	2008	4/28/2008	4.5597	5	2008	5/16/2008	6.29	5	2008	5/16/2008	6.27	5	2008
4	2008	4/29/2008	4.5509	5	2008	5/19/2008	6.28	5	2008	5/19/2008	6.25	5	2008
4	2008	4/30/2008	4.4672	5	2008	5/20/2008	6.24	5	2008	5/20/2008	6.22	5	2008
5	2008	5/1/2008	4.4991	5	2008	5/21/2008	6.27	5	2008	5/21/2008	6.24	5	2008
5	2008	5/2/2008	4.5775	5	2008	5/22/2008	6.34	5	2008	5/22/2008	6.29	5	2008
5	2008	5/5/2008	4.6014	5	2008	5/23/2008	6.27	5	2008	5/23/2008	6.22	5	2008
5	2008	5/6/2008	4.6625	5	2008	5/27/2008	6.37	5	2008	5/27/2008	6.32	5	2008
5	2008	5/7/2008	4.6054	5	2008	5/28/2008	6.42	5	2008	5/28/2008	6.37	5	2008
5	2008	5/8/2008	4.5421	5	2008	5/29/2008	6.49	5	2008	5/29/2008	6.42	5	2008
5	2008	5/9/2008	4.5216	5	2008	5/30/2008	6.42	5	2008	5/30/2008	6.36	5	2008
5	2008	5/12/2008	4.5343	6	2008	6/2/2008	6.39	6	2008	6/2/2008	6.34	6	2008
5	2008	5/13/2008	4.6384	6	2008	6/3/2008	6.32	6	2008	6/3/2008	6.27	6	2008
5	2008	5/14/2008	4.6134	6	2008	6/4/2008	6.39	6	2008	6/4/2008	6.34	6	2008
5	2008	5/15/2008	4.551	6	2008	6/5/2008	6.44	6	2008	6/5/2008	6.38	6	2008
5	2008	5/16/2008	4.5737	6	2008	6/6/2008	6.35	6	2008	6/6/2008	6.29	6	2008
5	2008	5/19/2008	4.5717	6	2008	6/9/2008	6.33	6	2008	6/9/2008	6.26	6	2008
5	2008	5/20/2008	4.5294	6	2008	6/10/2008	6.42	6	2008	6/10/2008	6.35	6	2008
5	2008	5/21/2008	4.5392	6	2008	6/11/2008	6.43	6	2008	6/11/2008	6.37	6	2008
5	2008	5/22/2008	4.6205	6	2008	6/12/2008	6.49	6	2008	6/12/2008	6.44	6	2008
5	2008	5/23/2008	4.5678	6	2008	6/13/2008	6.52	6	2008	6/13/2008	6.48	6	2008
5	2008	5/26/2008	4.5728	6	2008	6/16/2008	6.51	6	2008	6/16/2008	6.47	6	2008
5	2008	5/27/2008	4.6406	6	2008	6/17/2008	6.52	6	2008	6/17/2008	6.48	6	2008
5	2008	5/28/2008	4.6881	6	2008	6/18/2008	6.46	6	2008	6/18/2008	6.42	6	2008
5	2008	5/29/2008	4.7475	6	2008	6/19/2008	6.49	6	2008	6/19/2008	6.44	6	2008
5	2008	5/30/2008	4.7147	6	2008	6/20/2008	6.45	6	2008	6/20/2008	6.4	6	2008
6	2008	6/2/2008	4.67	6	2008	6/23/2008	6.46	6	2008	6/23/2008	6.41	6	2008
6	2008	6/3/2008	4.6206	6	2008	6/24/2008	6.42	6	2008	6/24/2008	6.38	6	2008
6	2008	6/4/2008	4.6984	6	2008	6/25/2008	6.42	6	2008	6/25/2008	6.39	6	2008
6	2008	6/5/2008	4.7363	6	2008	6/26/2008	6.42	6	2008	6/26/2008	6.38	6	2008
6	2008	6/6/2008	4.6237	6	2008	6/27/2008	6.35	6	2008	6/27/2008	6.31	6	2008
6	2008	6/9/2008	4.6297	6	2008	6/30/2008	6.36	6	2008	6/30/2008	6.32	6	2008

6	2008	6/10/2008	4.6985	7	2008	7/1/2008	6.38	7	2008	7/1/2008	6.34	7	2008
6	2008	6/11/2008	4.6945	7	2008	7/2/2008	6.33	7	2008	7/2/2008	6.3	7	2008
6	2008	6/12/2008	4.7571	7	2008	7/3/2008	6.37	7	2008	7/3/2008	6.33	7	2008
6	2008	6/13/2008	4.7893	7	2008	7/7/2008	6.34	7	2008	7/7/2008	6.3	7	2008
6	2008	6/16/2008	4.7914	7	2008	7/8/2008	6.3	7	2008	7/8/2008	6.26	7	2008
6	2008	6/17/2008	4.7675	7	2008	7/9/2008	6.28	7	2008	7/9/2008	6.23	7	2008
6	2008	6/18/2008	4.713	7	2008	7/10/2008	6.28	7	2008	7/10/2008	6.22	7	2008
6	2008	6/19/2008	4.7582	7	2008	7/11/2008	6.38	7	2008	7/11/2008	6.33	7	2008
6	2008	6/20/2008	4.7243	7	2008	7/14/2008	6.33	7	2008	7/14/2008	6.29	7	2008
6	2008	6/23/2008	4.7008	7	2008	7/15/2008	6.36	7	2008	7/15/2008	6.32	7	2008
6	2008	6/24/2008	4.636	7	2008	7/16/2008	6.48	7	2008	7/16/2008	6.44	7	2008
6	2008	6/25/2008	4.643	7	2008	7/17/2008	6.54	7	2008	7/17/2008	6.49	7	2008
6	2008	6/26/2008	4.601	7	2008	7/18/2008	6.56	7	2008	7/18/2008	6.51	7	2008
6	2008	6/27/2008	4.521	7	2008	7/21/2008	6.54	7	2008	7/21/2008	6.49	7	2008
6	2008	6/30/2008	4.5239	7	2008	7/22/2008	6.56	7	2008	7/22/2008	6.51	7	2008
7	2008	7/1/2008	4.5485	7	2008	7/23/2008	6.59	7	2008	7/23/2008	6.54	7	2008
7	2008	7/2/2008	4.5025	7	2008	7/24/2008	6.5	7	2008	7/24/2008	6.45	7	2008
7	2008	7/3/2008	4.5348	7	2008	7/25/2008	6.58	7	2008	7/25/2008	6.54	7	2008
7	2008	7/4/2008	4.5328	7	2008	7/28/2008	6.5	7	2008	7/28/2008	6.46	7	2008
7	2008	7/7/2008	4.484	7	2008	7/29/2008	6.51	7	2008	7/29/2008	6.46	7	2008
7	2008	7/8/2008	4.4502	7	2008	7/30/2008	6.53	7	2008	7/30/2008	6.48	7	2008
7	2008	7/9/2008	4.4176	7	2008	7/31/2008	6.49	7	2008	7/31/2008	6.44	7	2008
7	2008	7/10/2008	4.4138	8	2008	8/1/2008	6.47	8	2008	8/1/2008	6.42	8	2008
7	2008	7/11/2008	4.5398	8	2008	8/4/2008	6.48	8	2008	8/4/2008	6.43	8	2008
7	2008	7/14/2008	4.4464	8	2008	8/5/2008	6.52	8	2008	8/5/2008	6.47	8	2008
7	2008	7/15/2008	4.458	8	2008	8/6/2008	6.58	8	2008	8/6/2008	6.53	8	2008
7	2008	7/16/2008	4.5853	8	2008	8/7/2008	6.47	8	2008	8/7/2008	6.42	8	2008
7	2008	7/17/2008	4.6073	8	2008	8/8/2008	6.45	8	2008	8/8/2008	6.41	8	2008
7	2008	7/18/2008	4.6475	8	2008	8/11/2008	6.51	8	2008	8/11/2008	6.46	8	2008
7	2008	7/21/2008	4.6214	8	2008	8/12/2008	6.46	8	2008	8/12/2008	6.4	8	2008
7	2008	7/22/2008	4.6587	8	2008	8/13/2008	6.47	8	2008	8/13/2008	6.41	8	2008
7	2008	7/23/2008	4.6739	8	2008	8/14/2008	6.43	8	2008	8/14/2008	6.37	8	2008
7	2008	7/24/2008	4.6014	8	2008	8/15/2008	6.39	8	2008	8/15/2008	6.33	8	2008
7	2008	7/25/2008	4.6852	8	2008	8/18/2008	6.35	8	2008	8/18/2008	6.3	8	2008
7	2008	7/28/2008	4.6015	8	2008	8/19/2008	6.38	8	2008	8/19/2008	6.33	8	2008
7	2008	7/29/2008	4.6235	8	2008	8/20/2008	6.36	8	2008	8/20/2008	6.31	8	2008
7	2008	7/30/2008	4.6447	8	2008	8/21/2008	6.39	8	2008	8/21/2008	6.35	8	2008
7	2008	7/31/2008	4.5727	8	2008	8/22/2008	6.4	8	2008	8/22/2008	6.36	8	2008
8	2008	8/1/2008	4.5608	8	2008	8/25/2008	6.34	8	2008	8/25/2008	6.3	8	2008
8	2008	8/4/2008	4.5896	8	2008	8/26/2008	6.35	8	2008	8/26/2008	6.3	8	2008
8	2008	8/5/2008	4.6408	8	2008	8/27/2008	6.32	8	2008	8/27/2008	6.28	8	2008
8	2008	8/6/2008	4.6925	8	2008	8/28/2008	6.34	8	2008	8/28/2008	6.29	8	2008

8	2008	8/7/2008	4.555	8	2008	8/29/2008	6.38	8	2008	8/29/2008	6.32	8	2008
8	2008	8/8/2008	4.5333	9	2008	9/2/2008	6.33	9	2008	9/2/2008	6.26	9	2008
8	2008	8/11/2008	4.6024	9	2008	9/3/2008	6.29	9	2008	9/3/2008	6.23	9	2008
8	2008	8/12/2008	4.5333	9	2008	9/4/2008	6.26	9	2008	9/4/2008	6.21	9	2008
8	2008	8/13/2008	4.5594	9	2008	9/5/2008	6.27	9	2008	9/5/2008	6.21	9	2008
8	2008	8/14/2008	4.5169	9	2008	9/8/2008	6.27	9	2008	9/8/2008	6.2	9	2008
8	2008	8/15/2008	4.4634	9	2008	9/9/2008	6.2	9	2008	9/9/2008	6.14	9	2008
8	2008	8/18/2008	4.434	9	2008	9/10/2008	6.26	9	2008	9/10/2008	6.19	9	2008
8	2008	8/19/2008	4.4615	9	2008	9/11/2008	6.27	9	2008	9/11/2008	6.22	9	2008
8	2008	8/20/2008	4.4453	9	2008	9/12/2008	6.4	9	2008	9/12/2008	6.34	9	2008
8	2008	8/21/2008	4.4624	9	2008	9/15/2008	6.34	9	2008	9/15/2008	6.31	9	2008
8	2008	8/22/2008	4.4662	9	2008	9/16/2008	6.35	9	2008	9/16/2008	6.34	9	2008
8	2008	8/25/2008	4.3936	9	2008	9/17/2008	6.42	9	2008	9/17/2008	6.43	9	2008
8	2008	8/26/2008	4.3871	9	2008	9/18/2008	6.5	9	2008	9/18/2008	6.49	9	2008
8	2008	8/27/2008	4.3815	9	2008	9/19/2008	6.73	9	2008	9/19/2008	6.78	9	2008
8	2008	8/28/2008	4.3759	9	2008	9/22/2008	6.76	9	2008	9/22/2008	6.79	9	2008
8	2008	8/29/2008	4.4227	9	2008	9/23/2008	6.78	9	2008	9/23/2008	6.81	9	2008
9	2008	9/1/2008	4.4227	9	2008	9/24/2008	6.74	9	2008	9/24/2008	6.76	9	2008
9	2008	9/2/2008	4.3554	9	2008	9/25/2008	6.87	9	2008	9/25/2008	6.93	9	2008
9	2008	9/3/2008	4.3185	9	2008	9/26/2008	6.87	9	2008	9/26/2008	6.92	9	2008
9	2008	9/4/2008	4.2592	9	2008	9/29/2008	6.74	9	2008	9/29/2008	6.82	9	2008
9	2008	9/5/2008	4.3019	9	2008	9/30/2008	6.94	9	2008	9/30/2008	6.98	9	2008
9	2008	9/8/2008	4.2664	10	2008	10/1/2008	6.92	10	2008	10/1/2008	6.93	10	2008
9	2008	9/9/2008	4.1703	10	2008	10/2/2008	6.97	10	2008	10/2/2008	6.97	10	2008
9	2008	9/10/2008	4.2257	10	2008	10/3/2008	6.95	10	2008	10/3/2008	6.94	10	2008
9	2008	9/11/2008	4.2212	10	2008	10/6/2008	6.87	10	2008	10/6/2008	6.86	10	2008
9	2008	9/12/2008	4.3147	10	2008	10/7/2008	6.97	10	2008	10/7/2008	6.95	10	2008
9	2008	9/15/2008	4.0227	10	2008	10/8/2008	7.11	10	2008	10/8/2008	7.1	10	2008
9	2008	9/16/2008	4.091	10	2008	10/9/2008	7.22	10	2008	10/9/2008	7.2	10	2008
9	2008	9/17/2008	4.0736	10	2008	10/10/2008	7.5	10	2008	10/10/2008	7.44	10	2008
9	2008	9/18/2008	4.1889	10	2008	10/14/2008	7.64	10	2008	10/14/2008	7.56	10	2008
9	2008	9/19/2008	4.3823	10	2008	10/15/2008	7.66	10	2008	10/15/2008	7.63	10	2008
9	2008	9/22/2008	4.4208	10	2008	10/16/2008	7.75	10	2008	10/16/2008	7.74	10	2008
9	2008	9/23/2008	4.3804	10	2008	10/17/2008	7.98	10	2008	10/17/2008	8.02	10	2008
9	2008	9/24/2008	4.4123	10	2008	10/20/2008	7.96	10	2008	10/20/2008	8	10	2008
9	2008	9/25/2008	4.4095	10	2008	10/21/2008	7.91	10	2008	10/21/2008	7.93	10	2008
9	2008	9/26/2008	4.3702	10	2008	10/22/2008	7.77	10	2008	10/22/2008	7.8	10	2008
9	2008	9/29/2008	4.1127	10	2008	10/23/2008	7.63	10	2008	10/23/2008	7.69	10	2008
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10	2008	10/13/2008	4.1362	11	2008	11/6/2008	7.77	11	2008	11/6/2008	7.75	11	2008
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10	2008	10/27/2008	4.0453	11	2008	11/21/2008	7.42	11	2008	11/21/2008	7.36	11	2008
10	2008	10/28/2008	4.1912	11	2008	11/24/2008	7.54	11	2008	11/24/2008	7.47	11	2008
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11	2008	11/27/2008	3.5225	12	2008	12/26/2008	6.36	12	2008	12/26/2008	6.17	12	2008
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4	2009	4/17/2009	3.7981	5	2009	5/22/2009	6.89	5	2009	5/22/2009	6.58	5	2009
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4	2009	4/21/2009	3.7392	5	2009	5/27/2009	7.01	5	2009	5/27/2009	6.71	5	2009
4	2009	4/22/2009	3.8036	5	2009	5/28/2009	6.9	5	2009	5/28/2009	6.6	5	2009
4	2009	4/23/2009	3.7918	5	2009	5/29/2009	6.63	5	2009	5/29/2009	6.32	5	2009
4	2009	4/24/2009	3.8812	6	2009	6/1/2009	6.85	6	2009	6/1/2009	6.53	6	2009
4	2009	4/27/2009	3.8294	6	2009	6/2/2009	6.7	6	2009	6/2/2009	6.33	6	2009
4	2009	4/28/2009	3.9537	6	2009	6/3/2009	6.62	6	2009	6/3/2009	6.23	6	2009
4	2009	4/29/2009	4.0275	6	2009	6/4/2009	6.73	6	2009	6/4/2009	6.37	6	2009
4	2009	4/30/2009	4.0324	6	2009	6/5/2009	6.75	6	2009	6/5/2009	6.41	6	2009
5	2009	5/1/2009	4.0703	6	2009	6/8/2009	6.71	6	2009	6/8/2009	6.39	6	2009
5	2009	5/4/2009	4.048	6	2009	6/9/2009	6.71	6	2009	6/9/2009	6.38	6	2009
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5	2009	5/8/2009	4.2676	6	2009	6/15/2009	6.54	6	2009	6/15/2009	6.2	6	2009
5	2009	5/11/2009	4.1847	6	2009	6/16/2009	6.47	6	2009	6/16/2009	6.1	6	2009
5	2009	5/12/2009	4.1593	6	2009	6/17/2009	6.43	6	2009	6/17/2009	6.07	6	2009
5	2009	5/13/2009	4.099	6	2009	6/18/2009	6.57	6	2009	6/18/2009	6.23	6	2009
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5	2009	5/15/2009	4.0838	6	2009	6/22/2009	6.32	6	2009	6/22/2009	6.02	6	2009
5	2009	5/18/2009	4.1984	6	2009	6/23/2009	6.27	6	2009	6/23/2009	5.93	6	2009
5	2009	5/19/2009	4.2085	6	2009	6/24/2009	6.33	6	2009	6/24/2009	6.05	6	2009
5	2009	5/20/2009	4.1438	6	2009	6/25/2009	6.23	6	2009	6/25/2009	5.96	6	2009
5	2009	5/21/2009	4.3125	6	2009	6/26/2009	6.21	6	2009	6/26/2009	5.94	6	2009
5	2009	5/22/2009	4.3836	6	2009	6/29/2009	6.22	6	2009	6/29/2009	5.95	6	2009
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5	2009	5/26/2009	4.4912	7	2009	7/1/2009	6.26	7	2009	7/1/2009	6.01	7	2009
5	2009	5/27/2009	4.6319	7	2009	7/2/2009	6.21	7	2009	7/2/2009	5.97	7	2009

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5	2009	5/29/2009	4.3361	7	2009	7/7/2009	6.19	7	2009	7/7/2009	5.96	7	2009
6	2009	6/1/2009	4.5337	7	2009	7/8/2009	6.05	7	2009	7/8/2009	5.82	7	2009
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6	2009	6/24/2009	4.427	7	2009	7/31/2009	5.82	7	2009	7/31/2009	5.68	7	2009
6	2009	6/25/2009	4.3341	8	2009	8/3/2009	5.91	8	2009	8/3/2009	5.77	8	2009
6	2009	6/26/2009	4.336	8	2009	8/4/2009	5.92	8	2009	8/4/2009	5.81	8	2009
6	2009	6/29/2009	4.287	8	2009	8/5/2009	5.99	8	2009	8/5/2009	5.9	8	2009
6	2009	6/30/2009	4.3294	8	2009	8/6/2009	5.93	8	2009	8/6/2009	5.84	8	2009
7	2009	7/1/2009	4.3285	8	2009	8/7/2009	6.01	8	2009	8/7/2009	5.89	8	2009
7	2009	7/2/2009	4.3181	8	2009	8/10/2009	5.93	8	2009	8/10/2009	5.81	8	2009
7	2009	7/3/2009	4.3209	8	2009	8/11/2009	5.87	8	2009	8/11/2009	5.75	8	2009
7	2009	7/6/2009	4.3579	8	2009	8/12/2009	5.97	8	2009	8/12/2009	5.84	8	2009
7	2009	7/7/2009	4.3086	8	2009	8/13/2009	5.85	8	2009	8/13/2009	5.74	8	2009
7	2009	7/8/2009	4.1935	8	2009	8/14/2009	5.85	8	2009	8/14/2009	5.72	8	2009
7	2009	7/9/2009	4.3002	8	2009	8/17/2009	5.82	8	2009	8/17/2009	5.68	8	2009
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7	2009	7/13/2009	4.2321	8	2009	8/19/2009	5.79	8	2009	8/19/2009	5.66	8	2009
7	2009	7/14/2009	4.3741	8	2009	8/20/2009	5.75	8	2009	8/20/2009	5.61	8	2009
7	2009	7/15/2009	4.4886	8	2009	8/21/2009	5.86	8	2009	8/21/2009	5.73	8	2009
7	2009	7/16/2009	4.4475	8	2009	8/24/2009	5.78	8	2009	8/24/2009	5.65	8	2009
7	2009	7/17/2009	4.535	8	2009	8/25/2009	5.72	8	2009	8/25/2009	5.57	8	2009
7	2009	7/20/2009	4.5142	8	2009	8/26/2009	5.68	8	2009	8/26/2009	5.53	8	2009
7	2009	7/21/2009	4.3905	8	2009	8/27/2009	5.7	8	2009	8/27/2009	5.57	8	2009
7	2009	7/22/2009	4.4465	8	2009	8/28/2009	5.67	8	2009	8/28/2009	5.56	8	2009
7	2009	7/23/2009	4.55	8	2009	8/31/2009	5.65	8	2009	8/31/2009	5.54	8	2009
7	2009	7/24/2009	4.5391	9	2009	9/1/2009	5.66	9	2009	9/1/2009	5.55	9	2009

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7	2009	7/28/2009	4.5491	9	2009	9/3/2009	5.6	9	2009	9/3/2009	5.5	9	2009
7	2009	7/29/2009	4.5074	9	2009	9/4/2009	5.72	9	2009	9/4/2009	5.62	9	2009
7	2009	7/30/2009	4.4107	9	2009	9/8/2009	5.75	9	2009	9/8/2009	5.66	9	2009
7	2009	7/31/2009	4.2983	9	2009	9/9/2009	5.78	9	2009	9/9/2009	5.68	9	2009
8	2009	8/3/2009	4.404	9	2009	9/10/2009	5.61	9	2009	9/10/2009	5.52	9	2009
8	2009	8/4/2009	4.4632	9	2009	9/11/2009	5.6	9	2009	9/11/2009	5.52	9	2009
8	2009	8/5/2009	4.5492	9	2009	9/14/2009	5.65	9	2009	9/14/2009	5.57	9	2009
8	2009	8/6/2009	4.5333	9	2009	9/15/2009	5.69	9	2009	9/15/2009	5.61	9	2009
8	2009	8/7/2009	4.6045	9	2009	9/16/2009	5.68	9	2009	9/16/2009	5.61	9	2009
8	2009	8/10/2009	4.5313	9	2009	9/17/2009	5.59	9	2009	9/17/2009	5.52	9	2009
8	2009	8/11/2009	4.436	9	2009	9/18/2009	5.65	9	2009	9/18/2009	5.58	9	2009
8	2009	8/12/2009	4.5373	9	2009	9/21/2009	5.65	9	2009	9/21/2009	5.58	9	2009
8	2009	8/13/2009	4.4273	9	2009	9/22/2009	5.61	9	2009	9/22/2009	5.54	9	2009
8	2009	8/14/2009	4.4206	9	2009	9/23/2009	5.59	9	2009	9/23/2009	5.53	9	2009
8	2009	8/17/2009	4.3242	9	2009	9/24/2009	5.57	9	2009	9/24/2009	5.51	9	2009
8	2009	8/18/2009	4.3527	9	2009	9/25/2009	5.5	9	2009	9/25/2009	5.43	9	2009
8	2009	8/19/2009	4.2914	9	2009	9/28/2009	5.46	9	2009	9/28/2009	5.39	9	2009
8	2009	8/20/2009	4.2426	9	2009	9/29/2009	5.45	9	2009	9/29/2009	5.37	9	2009
8	2009	8/21/2009	4.3748	9	2009	9/30/2009	5.49	9	2009	9/30/2009	5.41	9	2009
8	2009	8/24/2009	4.2659	10	2009	10/1/2009	5.43	10	2009	10/1/2009	5.33	10	2009
8	2009	8/25/2009	4.2228	10	2009	10/2/2009	5.49	10	2009	10/2/2009	5.39	10	2009
8	2009	8/26/2009	4.1951	10	2009	10/5/2009	5.51	10	2009	10/5/2009	5.4	10	2009
8	2009	8/27/2009	4.2236	10	2009	10/6/2009	5.53	10	2009	10/6/2009	5.44	10	2009
8	2009	8/28/2009	4.2004	10	2009	10/7/2009	5.46	10	2009	10/7/2009	5.36	10	2009
8	2009	8/31/2009	4.1782	10	2009	10/8/2009	5.56	10	2009	10/8/2009	5.47	10	2009
9	2009	9/1/2009	4.1923	10	2009	10/9/2009	5.69	10	2009	10/9/2009	5.6	10	2009
9	2009	9/2/2009	4.1201	10	2009	10/13/2009	5.62	10	2009	10/13/2009	5.53	10	2009
9	2009	9/3/2009	4.1604	10	2009	10/14/2009	5.73	10	2009	10/14/2009	5.64	10	2009
9	2009	9/4/2009	4.2666	10	2009	10/15/2009	5.76	10	2009	10/15/2009	5.68	10	2009
9	2009	9/7/2009	4.2693	10	2009	10/16/2009	5.68	10	2009	10/16/2009	5.61	10	2009
9	2009	9/8/2009	4.3184	10	2009	10/19/2009	5.65	10	2009	10/19/2009	5.58	10	2009
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11	2009	11/27/2009	4.1998	1	2010	1/13/2010	5.82	1	2010	1/13/2010	5.84	1	2010
11	2009	11/30/2009	4.1917	1	2010	1/14/2010	5.74	1	2010	1/14/2010	5.77	1	2010
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12	2009	12/8/2009	4.3739	1	2010	1/25/2010	5.75	1	2010	1/25/2010	5.75	1	2010
12	2009	12/9/2009	4.4184	1	2010	1/26/2010	5.77	1	2010	1/26/2010	5.77	1	2010
12	2009	12/10/2009	4.5058	1	2010	1/27/2010	5.76	1	2010	1/27/2010	5.77	1	2010
12	2009	12/11/2009	4.5009	1	2010	1/28/2010	5.79	1	2010	1/28/2010	5.79	1	2010
12	2009	12/14/2009	4.4816	1	2010	1/29/2010	5.73	1	2010	1/29/2010	5.73	1	2010
12	2009	12/15/2009	4.5213	2	2010	2/1/2010	5.79	2	2010	2/1/2010	5.79	2	2010
12	2009	12/16/2009	4.5243	2	2010	2/2/2010	5.77	2	2010	2/2/2010	5.77	2	2010
12	2009	12/17/2009	4.4164	2	2010	2/3/2010	5.85	2	2010	2/3/2010	5.86	2	2010
12	2009	12/18/2009	4.4575	2	2010	2/4/2010	5.77	2	2010	2/4/2010	5.78	2	2010
12	2009	12/21/2009	4.5586	2	2010	2/5/2010	5.74	2	2010	2/5/2010	5.74	2	2010
12	2009	12/22/2009	4.61	2	2010	2/8/2010	5.78	2	2010	2/8/2010	5.79	2	2010
12	2009	12/23/2009	4.607	2	2010	2/9/2010	5.84	2	2010	2/9/2010	5.84	2	2010
12	2009	12/24/2009	4.6833	2	2010	2/10/2010	5.9	2	2010	2/10/2010	5.91	2	2010
12	2009	12/25/2009	4.6834	2	2010	2/11/2010	5.94	2	2010	2/11/2010	5.95	2	2010
12	2009	12/28/2009	4.6894	2	2010	2/12/2010	5.92	2	2010	2/12/2010	5.93	2	2010
12	2009	12/29/2009	4.637	2	2010	2/16/2010	5.9	2	2010	2/16/2010	5.91	2	2010
12	2009	12/30/2009	4.6091	2	2010	2/17/2010	5.97	2	2010	2/17/2010	5.99	2	2010
12	2009	12/31/2009	4.6411	2	2010	2/18/2010	6.01	2	2010	2/18/2010	6.01	2	2010
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1	2010	1/4/2010	4.6431	2	2010	2/22/2010	5.97	2	2010	2/22/2010	5.98	2	2010
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1	2010	1/6/2010	4.6875	2	2010	2/24/2010	5.86	2	2010	2/24/2010	5.88	2	2010
1	2010	1/7/2010	4.6855	2	2010	2/25/2010	5.8	2	2010	2/25/2010	5.82	2	2010
1	2010	1/8/2010	4.715	2	2010	2/26/2010	5.75	2	2010	2/26/2010	5.77	2	2010
1	2010	1/11/2010	4.7314	3	2010	3/1/2010	5.78	3	2010	3/1/2010	5.79	3	2010
1	2010	1/12/2010	4.6171	3	2010	3/2/2010	5.78	3	2010	3/2/2010	5.79	3	2010
1	2010	1/13/2010	4.712	3	2010	3/3/2010	5.79	3	2010	3/3/2010	5.81	3	2010
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1	2010	1/15/2010	4.5814	3	2010	3/5/2010	5.83	3	2010	3/5/2010	5.86	3	2010
1	2010	1/18/2010	4.5814	3	2010	3/8/2010	5.84	3	2010	3/8/2010	5.88	3	2010

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2	2010	2/3/2010	4.6383	3	2010	3/24/2010	5.87	3	2010	3/24/2010	5.9	3	2010
2	2010	2/4/2010	4.5499	3	2010	3/25/2010	5.93	3	2010	3/25/2010	5.96	3	2010
2	2010	2/5/2010	4.5186	3	2010	3/26/2010	5.89	3	2010	3/26/2010	5.93	3	2010
2	2010	2/8/2010	4.4972	3	2010	3/29/2010	5.9	3	2010	3/29/2010	5.94	3	2010
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2	2010	2/12/2010	4.6463	4	2010	4/2/2010	5.93	4	2010	4/2/2010	5.98	4	2010
2	2010	2/15/2010	4.6493	4	2010	4/5/2010	5.97	4	2010	4/5/2010	6.02	4	2010
2	2010	2/16/2010	4.6318	4	2010	4/6/2010	5.97	4	2010	4/6/2010	6.01	4	2010
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3	2010	3/12/2010	4.6248	4	2010	4/30/2010	5.61	4	2010	4/30/2010	5.6	4	2010
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4	2010	4/5/2010	4.8395	5	2010	5/24/2010	5.42	5	2010	5/24/2010	5.38	5	2010
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7	2010	7/13/2010	4.1062	9	2010	9/2/2010	5.02	9	2010	9/2/2010	4.97	9	2010

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7	2010	7/30/2010	3.9881	9	2010	9/22/2010	5.01	9	2010	9/22/2010	4.97	9	2010
8	2010	8/2/2010	4.0619	9	2010	9/23/2010	5	9	2010	9/23/2010	4.97	9	2010
8	2010	8/3/2010	4.0488	9	2010	9/24/2010	5.07	9	2010	9/24/2010	5.03	9	2010
8	2010	8/4/2010	4.0795	9	2010	9/27/2010	4.98	9	2010	9/27/2010	4.94	9	2010
8	2010	8/5/2010	4.0505	9	2010	9/28/2010	4.94	9	2010	9/28/2010	4.88	9	2010
8	2010	8/6/2010	3.994	9	2010	9/29/2010	4.98	9	2010	9/29/2010	4.93	9	2010
8	2010	8/9/2010	4.0165	9	2010	9/30/2010	4.99	9	2010	9/30/2010	4.93	9	2010
8	2010	8/10/2010	4.0044	10	2010	10/1/2010	5.02	10	2010	10/1/2010	4.96	10	2010
8	2010	8/11/2010	3.9188	10	2010	10/4/2010	5.02	10	2010	10/4/2010	4.96	10	2010
8	2010	8/12/2010	3.9476	10	2010	10/5/2010	5.03	10	2010	10/5/2010	4.98	10	2010
8	2010	8/13/2010	3.8538	10	2010	10/6/2010	4.96	10	2010	10/6/2010	4.91	10	2010
8	2010	8/16/2010	3.711	10	2010	10/7/2010	5.01	10	2010	10/7/2010	4.96	10	2010
8	2010	8/17/2010	3.7632	10	2010	10/8/2010	5.04	10	2010	10/8/2010	4.99	10	2010
8	2010	8/18/2010	3.7331	10	2010	10/12/2010	5.09	10	2010	10/12/2010	5.04	10	2010
8	2010	8/19/2010	3.6543	10	2010	10/13/2010	5.11	10	2010	10/13/2010	5.07	10	2010
8	2010	8/20/2010	3.6601	10	2010	10/14/2010	5.18	10	2010	10/14/2010	5.14	10	2010
8	2010	8/23/2010	3.6618	10	2010	10/15/2010	5.27	10	2010	10/15/2010	5.23	10	2010
8	2010	8/24/2010	3.5605	10	2010	10/18/2010	5.21	10	2010	10/18/2010	5.15	10	2010
8	2010	8/25/2010	3.5695	10	2010	10/19/2010	5.18	10	2010	10/19/2010	5.13	10	2010
8	2010	8/26/2010	3.5115	10	2010	10/20/2010	5.16	10	2010	10/20/2010	5.11	10	2010
8	2010	8/27/2010	3.6896	10	2010	10/21/2010	5.2	10	2010	10/21/2010	5.17	10	2010
8	2010	8/30/2010	3.5809	10	2010	10/22/2010	5.2	10	2010	10/22/2010	5.17	10	2010
8	2010	8/31/2010	3.5155	10	2010	10/25/2010	5.16	10	2010	10/25/2010	5.13	10	2010
9	2010	9/1/2010	3.6457	10	2010	10/26/2010	5.25	10	2010	10/26/2010	5.22	10	2010
9	2010	9/2/2010	3.7141	10	2010	10/27/2010	5.28	10	2010	10/27/2010	5.26	10	2010
9	2010	9/3/2010	3.7811	10	2010	10/28/2010	5.3	10	2010	10/28/2010	5.27	10	2010
9	2010	9/6/2010	3.7837	10	2010	10/29/2010	5.23	10	2010	10/29/2010	5.21	10	2010
9	2010	9/7/2010	3.6616	11	2010	11/1/2010	5.24	11	2010	11/1/2010	5.22	11	2010
9	2010	9/8/2010	3.7294	11	2010	11/2/2010	5.16	11	2010	11/2/2010	5.14	11	2010
9	2010	9/9/2010	3.8387	11	2010	11/3/2010	5.28	11	2010	11/3/2010	5.26	11	2010

9	2010	9/10/2010	3.8687	11	2010	11/4/2010	5.24	11	2010	11/4/2010	5.23	11	2010
9	2010	9/13/2010	3.8483	11	2010	11/5/2010	5.31	11	2010	11/5/2010	5.31	11	2010
9	2010	9/14/2010	3.7993	11	2010	11/8/2010	5.31	11	2010	11/8/2010	5.32	11	2010
9	2010	9/15/2010	3.8713	11	2010	11/9/2010	5.42	11	2010	11/9/2010	5.42	11	2010
9	2010	9/16/2010	3.9248	11	2010	11/10/2010	5.41	11	2010	11/10/2010	5.41	11	2010
9	2010	9/17/2010	3.9033	11	2010	11/11/2010	5.42	11	2010	11/11/2010	5.42	11	2010
9	2010	9/20/2010	3.8757	11	2010	11/12/2010	5.44	11	2010	11/12/2010	5.44	11	2010
9	2010	9/21/2010	3.7845	11	2010	11/15/2010	5.56	11	2010	11/15/2010	5.55	11	2010
9	2010	9/22/2010	3.7499	11	2010	11/16/2010	5.45	11	2010	11/16/2010	5.44	11	2010
9	2010	9/23/2010	3.7301	11	2010	11/17/2010	5.47	11	2010	11/17/2010	5.46	11	2010
9	2010	9/24/2010	3.794	11	2010	11/18/2010	5.47	11	2010	11/18/2010	5.47	11	2010
9	2010	9/27/2010	3.7181	11	2010	11/19/2010	5.43	11	2010	11/19/2010	5.43	11	2010
9	2010	9/28/2010	3.6579	11	2010	11/22/2010	5.39	11	2010	11/22/2010	5.38	11	2010
9	2010	9/29/2010	3.6841	11	2010	11/23/2010	5.35	11	2010	11/23/2010	5.35	11	2010
9	2010	9/30/2010	3.6849	11	2010	11/24/2010	5.48	11	2010	11/24/2010	5.47	11	2010
10	2010	10/1/2010	3.7147	11	2010	11/26/2010	5.38	11	2010	11/26/2010	5.38	11	2010
10	2010	10/4/2010	3.7061	11	2010	11/29/2010	5.33	11	2010	11/29/2010	5.33	11	2010
10	2010	10/5/2010	3.7472	11	2010	11/30/2010	5.29	11	2010	11/30/2010	5.28	11	2010
10	2010	10/6/2010	3.6747	12	2010	12/1/2010	5.42	12	2010	12/1/2010	5.41	12	2010
10	2010	10/7/2010	3.7121	12	2010	12/2/2010	5.44	12	2010	12/2/2010	5.44	12	2010
10	2010	10/8/2010	3.7489	12	2010	12/3/2010	5.49	12	2010	12/3/2010	5.48	12	2010
10	2010	10/11/2010	3.7489	12	2010	12/6/2010	5.42	12	2010	12/6/2010	5.42	12	2010
10	2010	10/12/2010	3.8192	12	2010	12/7/2010	5.59	12	2010	12/7/2010	5.59	12	2010
10	2010	10/13/2010	3.8166	12	2010	12/8/2010	5.6	12	2010	12/8/2010	5.61	12	2010
10	2010	10/14/2010	3.9149	12	2010	12/9/2010	5.54	12	2010	12/9/2010	5.56	12	2010
10	2010	10/15/2010	3.9791	12	2010	12/10/2010	5.57	12	2010	12/10/2010	5.58	12	2010
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10	2010	10/19/2010	3.9131	12	2010	12/14/2010	5.69	12	2010	12/14/2010	5.7	12	2010
10	2010	10/20/2010	3.8899	12	2010	12/15/2010	5.73	12	2010	12/15/2010	5.74	12	2010
10	2010	10/21/2010	3.9609	12	2010	12/16/2010	5.69	12	2010	12/16/2010	5.71	12	2010
10	2010	10/22/2010	3.9293	12	2010	12/17/2010	5.52	12	2010	12/17/2010	5.54	12	2010
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10	2010	10/28/2010	4.049	12	2010	12/23/2010	5.57	12	2010	12/23/2010	5.58	12	2010
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11	2010	11/1/2010	4.0029	12	2010	12/28/2010	5.64	12	2010	12/28/2010	5.65	12	2010
11	2010	11/2/2010	3.9266	12	2010	12/29/2010	5.5	12	2010	12/29/2010	5.52	12	2010
11	2010	11/3/2010	4.0398	12	2010	12/30/2010	5.52	12	2010	12/30/2010	5.54	12	2010
11	2010	11/4/2010	4.0713	12	2010	12/31/2010	5.44	12	2010	12/31/2010	5.45	12	2010
11	2010	11/5/2010	4.1192	1	2011	1/3/2011	5.49	1	2011	1/3/2011	5.5	1	2011
11	2010	11/8/2010	4.1201	1	2011	1/4/2011	5.52	1	2011	1/4/2011	5.53	1	2011

11	2010	11/9/2010	4.2466	1	2011	1/5/2011	5.61	1	2011	1/5/2011	5.63	1	2011
11	2010	11/10/2010	4.2311	1	2011	1/6/2011	5.57	1	2011	1/6/2011	5.59	1	2011
11	2010	11/11/2010	4.243	1	2011	1/7/2011	5.53	1	2011	1/7/2011	5.55	1	2011
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11	2010	11/15/2010	4.4153	1	2011	1/11/2011	5.51	1	2011	1/11/2011	5.53	1	2011
11	2010	11/16/2010	4.2648	1	2011	1/12/2011	5.54	1	2011	1/12/2011	5.55	1	2011
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11	2010	11/25/2010	4.275	1	2011	1/24/2011	5.57	1	2011	1/24/2011	5.59	1	2011
11	2010	11/26/2010	4.2093	1	2011	1/25/2011	5.49	1	2011	1/25/2011	5.5	1	2011
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12	2010	12/3/2010	4.3143	2	2011	2/1/2011	5.63	2	2011	2/1/2011	5.65	2	2011
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12	2010	12/7/2010	4.3674	2	2011	2/3/2011	5.68	2	2011	2/3/2011	5.7	2	2011
12	2010	12/8/2010	4.4561	2	2011	2/4/2011	5.75	2	2011	2/4/2011	5.77	2	2011
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12	2010	12/10/2010	4.4289	2	2011	2/8/2011	5.77	2	2011	2/8/2011	5.79	2	2011
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3	2011	3/18/2011	4.4166	5	2011	5/19/2011	5.33	5	2011	5/19/2011	5.32	5	2011
3	2011	3/21/2011	4.4514	5	2011	5/20/2011	5.33	5	2011	5/20/2011	5.32	5	2011
3	2011	3/22/2011	4.4367	5	2011	5/23/2011	5.3	5	2011	5/23/2011	5.29	5	2011
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3	2011	3/25/2011	4.5002	5	2011	5/26/2011	5.26	5	2011	5/26/2011	5.24	5	2011
3	2011	3/28/2011	4.4946	5	2011	5/27/2011	5.28	5	2011	5/27/2011	5.25	5	2011
3	2011	3/29/2011	4.5441	5	2011	5/31/2011	5.26	5	2011	5/31/2011	5.23	5	2011
3	2011	3/30/2011	4.502	6	2011	6/1/2011	5.2	6	2011	6/1/2011	5.16	6	2011
3	2011	3/31/2011	4.5076	6	2011	6/2/2011	5.31	6	2011	6/2/2011	5.27	6	2011
4	2011	4/1/2011	4.4853	6	2011	6/3/2011	5.28	6	2011	6/3/2011	5.25	6	2011
4	2011	4/4/2011	4.476	6	2011	6/6/2011	5.32	6	2011	6/6/2011	5.28	6	2011
4	2011	4/5/2011	4.5038	6	2011	6/7/2011	5.32	6	2011	6/7/2011	5.29	6	2011
4	2011	4/6/2011	4.5949	6	2011	6/8/2011	5.27	6	2011	6/8/2011	5.23	6	2011
4	2011	4/7/2011	4.6159	6	2011	6/9/2011	5.29	6	2011	6/9/2011	5.25	6	2011
4	2011	4/8/2011	4.6417	6	2011	6/10/2011	5.25	6	2011	6/10/2011	5.21	6	2011
4	2011	4/11/2011	4.6542	6	2011	6/13/2011	5.28	6	2011	6/13/2011	5.23	6	2011
4	2011	4/12/2011	4.575	6	2011	6/14/2011	5.37	6	2011	6/14/2011	5.33	6	2011
4	2011	4/13/2011	4.5429	6	2011	6/15/2011	5.27	6	2011	6/15/2011	5.23	6	2011
4	2011	4/14/2011	4.5485	6	2011	6/16/2011	5.23	6	2011	6/16/2011	5.19	6	2011
4	2011	4/15/2011	4.4684	6	2011	6/17/2011	5.27	6	2011	6/17/2011	5.23	6	2011
4	2011	4/18/2011	4.4564	6	2011	6/20/2011	5.28	6	2011	6/20/2011	5.24	6	2011
4	2011	4/19/2011	4.4316	6	2011	6/21/2011	5.29	6	2011	6/21/2011	5.25	6	2011
4	2011	4/20/2011	4.4656	6	2011	6/22/2011	5.3	6	2011	6/22/2011	5.26	6	2011
4	2011	4/21/2011	4.4739	6	2011	6/23/2011	5.23	6	2011	6/23/2011	5.19	6	2011
4	2011	4/22/2011	4.4646	6	2011	6/24/2011	5.25	6	2011	6/24/2011	5.21	6	2011
4	2011	4/25/2011	4.4554	6	2011	6/27/2011	5.36	6	2011	6/27/2011	5.31	6	2011
4	2011	4/26/2011	4.3905	6	2011	6/28/2011	5.41	6	2011	6/28/2011	5.37	6	2011
4	2011	4/27/2011	4.4526	6	2011	6/29/2011	5.44	6	2011	6/29/2011	5.4	6	2011
4	2011	4/28/2011	4.4141	6	2011	6/30/2011	5.45	6	2011	6/30/2011	5.41	6	2011
4	2011	4/29/2011	4.3968	7	2011	7/1/2011	5.46	7	2011	7/1/2011	5.42	7	2011
5	2011	5/2/2011	4.3786	7	2011	7/5/2011	5.45	7	2011	7/5/2011	5.4	7	2011
5	2011	5/3/2011	4.3507	7	2011	7/6/2011	5.41	7	2011	7/6/2011	5.37	7	2011

5	2011	5/4/2011	4.3211	7	2011	7/7/2011	5.41	7	2011	7/7/2011	5.38	7	2011
5	2011	5/5/2011	4.2556	7	2011	7/8/2011	5.32	7	2011	7/8/2011	5.28	7	2011
5	2011	5/6/2011	4.2855	7	2011	7/11/2011	5.24	7	2011	7/11/2011	5.21	7	2011
5	2011	5/9/2011	4.3085	7	2011	7/12/2011	5.22	7	2011	7/12/2011	5.2	7	2011
5	2011	5/10/2011	4.3506	7	2011	7/13/2011	5.21	7	2011	7/13/2011	5.19	7	2011
5	2011	5/11/2011	4.3032	7	2011	7/14/2011	5.27	7	2011	7/14/2011	5.25	7	2011
5	2011	5/12/2011	4.3469	7	2011	7/15/2011	5.28	7	2011	7/15/2011	5.25	7	2011
5	2011	5/13/2011	4.3078	7	2011	7/18/2011	5.31	7	2011	7/18/2011	5.28	7	2011
5	2011	5/16/2011	4.2719	7	2011	7/19/2011	5.22	7	2011	7/19/2011	5.19	7	2011
5	2011	5/17/2011	4.2271	7	2011	7/20/2011	5.29	7	2011	7/20/2011	5.26	7	2011
5	2011	5/18/2011	4.2949	7	2011	7/21/2011	5.33	7	2011	7/21/2011	5.3	7	2011
5	2011	5/19/2011	4.3032	7	2011	7/22/2011	5.27	7	2011	7/22/2011	5.24	7	2011
5	2011	5/20/2011	4.2976	7	2011	7/25/2011	5.33	7	2011	7/25/2011	5.3	7	2011
5	2011	5/23/2011	4.2663	7	2011	7/26/2011	5.28	7	2011	7/26/2011	5.24	7	2011
5	2011	5/24/2011	4.2498	7	2011	7/27/2011	5.27	7	2011	7/27/2011	5.24	7	2011
5	2011	5/25/2011	4.2819	7	2011	7/28/2011	5.24	7	2011	7/28/2011	5.21	7	2011
5	2011	5/26/2011	4.2225	7	2011	7/29/2011	5.12	7	2011	7/29/2011	5.09	7	2011
5	2011	5/27/2011	4.2424	8	2011	8/1/2011	5.04	8	2011	8/1/2011	5.02	8	2011
5	2011	5/30/2011	4.2424	8	2011	8/2/2011	4.89	8	2011	8/2/2011	4.87	8	2011
5	2011	5/31/2011	4.2242	8	2011	8/3/2011	4.85	8	2011	8/3/2011	4.82	8	2011
6	2011	6/1/2011	4.1415	8	2011	8/4/2011	4.72	8	2011	8/4/2011	4.67	8	2011
6	2011	6/2/2011	4.2442	8	2011	8/5/2011	4.83	8	2011	8/5/2011	4.77	8	2011
6	2011	6/3/2011	4.2224	8	2011	8/8/2011	4.75	8	2011	8/8/2011	4.67	8	2011
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6	2011	6/7/2011	4.2579	8	2011	8/10/2011	4.65	8	2011	8/10/2011	4.54	8	2011
6	2011	6/8/2011	4.1853	8	2011	8/11/2011	4.92	8	2011	8/11/2011	4.8	8	2011
6	2011	6/9/2011	4.215	8	2011	8/12/2011	4.81	8	2011	8/12/2011	4.71	8	2011
6	2011	6/10/2011	4.1816	8	2011	8/15/2011	4.87	8	2011	8/15/2011	4.77	8	2011
6	2011	6/13/2011	4.2005	8	2011	8/16/2011	4.78	8	2011	8/16/2011	4.68	8	2011
6	2011	6/14/2011	4.2964	8	2011	8/17/2011	4.73	8	2011	8/17/2011	4.6	8	2011
6	2011	6/15/2011	4.1996	8	2011	8/18/2011	4.63	8	2011	8/18/2011	4.51	8	2011
6	2011	6/16/2011	4.1753	8	2011	8/19/2011	4.6	8	2011	8/19/2011	4.47	8	2011
6	2011	6/17/2011	4.205	8	2011	8/22/2011	4.63	8	2011	8/22/2011	4.49	8	2011
6	2011	6/20/2011	4.1977	8	2011	8/23/2011	4.73	8	2011	8/23/2011	4.57	8	2011
6	2011	6/21/2011	4.2185	8	2011	8/24/2011	4.87	8	2011	8/24/2011	4.74	8	2011
6	2011	6/22/2011	4.2149	8	2011	8/25/2011	4.86	8	2011	8/25/2011	4.74	8	2011
6	2011	6/23/2011	4.168	8	2011	8/26/2011	4.8	8	2011	8/26/2011	4.67	8	2011
6	2011	6/24/2011	4.1832	8	2011	8/29/2011	4.89	8	2011	8/29/2011	4.76	8	2011
6	2011	6/27/2011	4.2954	8	2011	8/30/2011	4.78	8	2011	8/30/2011	4.66	8	2011
6	2011	6/28/2011	4.3242	8	2011	8/31/2011	4.86	8	2011	8/31/2011	4.74	8	2011
6	2011	6/29/2011	4.3766	9	2011	9/1/2011	4.78	9	2011	9/1/2011	4.67	9	2011
6	2011	6/30/2011	4.371	9	2011	9/2/2011	4.59	9	2011	9/2/2011	4.47	9	2011

7	2011	7/1/2011	4.3908	9	2011	9/6/2011	4.57	9	2011	9/6/2011	4.44	9	2011
7	2011	7/4/2011	4.3908	9	2011	9/7/2011	4.66	9	2011	9/7/2011	4.55	9	2011
7	2011	7/5/2011	4.3728	9	2011	9/8/2011	4.63	9	2011	9/8/2011	4.52	9	2011
7	2011	7/6/2011	4.3625	9	2011	9/9/2011	4.57	9	2011	9/9/2011	4.46	9	2011
7	2011	7/7/2011	4.3662	9	2011	9/12/2011	4.58	9	2011	9/12/2011	4.45	9	2011
7	2011	7/8/2011	4.2824	9	2011	9/13/2011	4.67	9	2011	9/13/2011	4.55	9	2011
7	2011	7/11/2011	4.2083	9	2011	9/14/2011	4.67	9	2011	9/14/2011	4.56	9	2011
7	2011	7/12/2011	4.1677	9	2011	9/15/2011	4.73	9	2011	9/15/2011	4.61	9	2011
7	2011	7/13/2011	4.1722	9	2011	9/16/2011	4.71	9	2011	9/16/2011	4.59	9	2011
7	2011	7/14/2011	4.2539	9	2011	9/19/2011	4.59	9	2011	9/19/2011	4.48	9	2011
7	2011	7/15/2011	4.2465	9	2011	9/20/2011	4.61	9	2011	9/20/2011	4.5	9	2011
7	2011	7/18/2011	4.3083	9	2011	9/21/2011	4.46	9	2011	9/21/2011	4.33	9	2011
7	2011	7/19/2011	4.1902	9	2011	9/22/2011	4.34	9	2011	9/22/2011	4.23	9	2011
7	2011	7/20/2011	4.252	9	2011	9/23/2011	4.44	9	2011	9/23/2011	4.32	9	2011
7	2011	7/21/2011	4.312	9	2011	9/26/2011	4.58	9	2011	9/26/2011	4.47	9	2011
7	2011	7/22/2011	4.2575	9	2011	9/27/2011	4.69	9	2011	9/27/2011	4.58	9	2011
7	2011	7/25/2011	4.3194	9	2011	9/28/2011	4.66	9	2011	9/28/2011	4.55	9	2011
7	2011	7/26/2011	4.2823	9	2011	9/29/2011	4.57	9	2011	9/29/2011	4.46	9	2011
7	2011	7/27/2011	4.2851	9	2011	9/30/2011	4.49	9	2011	9/30/2011	4.38	9	2011
7	2011	7/28/2011	4.2556	10	2011	10/3/2011	4.35	10	2011	10/3/2011	4.22	10	2011
7	2011	7/29/2011	4.1184	10	2011	10/4/2011	4.36	10	2011	10/4/2011	4.23	10	2011
8	2011	8/1/2011	4.0795	10	2011	10/5/2011	4.49	10	2011	10/5/2011	4.35	10	2011
8	2011	8/2/2011	3.9088	10	2011	10/6/2011	4.56	10	2011	10/6/2011	4.42	10	2011
8	2011	8/3/2011	3.902	10	2011	10/7/2011	4.62	10	2011	10/7/2011	4.48	10	2011
8	2011	8/4/2011	3.6707	10	2011	10/11/2011	4.7	10	2011	10/11/2011	4.57	10	2011
8	2011	8/5/2011	3.8458	10	2011	10/12/2011	4.77	10	2011	10/12/2011	4.66	10	2011
8	2011	8/8/2011	3.653	10	2011	10/13/2011	4.69	10	2011	10/13/2011	4.58	10	2011
8	2011	8/9/2011	3.6181	10	2011	10/14/2011	4.74	10	2011	10/14/2011	4.64	10	2011
8	2011	8/10/2011	3.5146	10	2011	10/17/2011	4.65	10	2011	10/17/2011	4.56	10	2011
8	2011	8/11/2011	3.769	10	2011	10/18/2011	4.63	10	2011	10/18/2011	4.56	10	2011
8	2011	8/12/2011	3.7257	10	2011	10/19/2011	4.61	10	2011	10/19/2011	4.54	10	2011
8	2011	8/15/2011	3.771	10	2011	10/20/2011	4.63	10	2011	10/20/2011	4.57	10	2011
8	2011	8/16/2011	3.6671	10	2011	10/21/2011	4.66	10	2011	10/21/2011	4.62	10	2011
8	2011	8/17/2011	3.5633	10	2011	10/24/2011	4.66	10	2011	10/24/2011	4.64	10	2011
8	2011	8/18/2011	3.4193	10	2011	10/25/2011	4.52	10	2011	10/25/2011	4.49	10	2011
8	2011	8/19/2011	3.3904	10	2011	10/26/2011	4.59	10	2011	10/26/2011	4.56	10	2011
8	2011	8/22/2011	3.4233	10	2011	10/27/2011	4.72	10	2011	10/27/2011	4.68	10	2011
8	2011	8/23/2011	3.4931	10	2011	10/28/2011	4.61	10	2011	10/28/2011	4.57	10	2011
8	2011	8/24/2011	3.6534	10	2011	10/31/2011	4.46	10	2011	10/31/2011	4.42	10	2011
8	2011	8/25/2011	3.6009	11	2011	11/1/2011	4.3	11	2011	11/1/2011	4.22	11	2011
8	2011	8/26/2011	3.535	11	2011	11/2/2011	4.33	11	2011	11/2/2011	4.24	11	2011
8	2011	8/29/2011	3.5916	11	2011	11/3/2011	4.41	11	2011	11/3/2011	4.32	11	2011

8	2011	8/30/2011	3.5225	11	2011	11/4/2011	4.39	11	2011	11/4/2011	4.3	11	2011
8	2011	8/31/2011	3.6008	11	2011	11/7/2011	4.33	11	2011	11/7/2011	4.24	11	2011
9	2011	9/1/2011	3.4945	11	2011	11/8/2011	4.42	11	2011	11/8/2011	4.32	11	2011
9	2011	9/2/2011	3.2969	11	2011	11/9/2011	4.33	11	2011	11/9/2011	4.21	11	2011
9	2011	9/5/2011	3.2969	11	2011	11/10/2011	4.44	11	2011	11/10/2011	4.32	11	2011
9	2011	9/6/2011	3.272	11	2011	11/14/2011	4.43	11	2011	11/14/2011	4.3	11	2011
9	2011	9/7/2011	3.367	11	2011	11/15/2011	4.46	11	2011	11/15/2011	4.32	11	2011
9	2011	9/8/2011	3.3086	11	2011	11/16/2011	4.43	11	2011	11/16/2011	4.28	11	2011
9	2011	9/9/2011	3.2463	11	2011	11/17/2011	4.36	11	2011	11/17/2011	4.21	11	2011
9	2011	9/12/2011	3.2509	11	2011	11/18/2011	4.41	11	2011	11/18/2011	4.23	11	2011
9	2011	9/13/2011	3.3273	11	2011	11/21/2011	4.36	11	2011	11/21/2011	4.19	11	2011
9	2011	9/14/2011	3.271	11	2011	11/22/2011	4.35	11	2011	11/22/2011	4.17	11	2011
9	2011	9/15/2011	3.3565	11	2011	11/23/2011	4.28	11	2011	11/23/2011	4.08	11	2011
9	2011	9/16/2011	3.313	11	2011	11/25/2011	4.38	11	2011	11/25/2011	4.19	11	2011
9	2011	9/19/2011	3.2184	11	2011	11/28/2011	4.4	11	2011	11/28/2011	4.19	11	2011
9	2011	9/20/2011	3.2024	11	2011	11/29/2011	4.46	11	2011	11/29/2011	4.28	11	2011
9	2011	9/21/2011	2.9942	11	2011	11/30/2011	4.57	11	2011	11/30/2011	4.38	11	2011
9	2011	9/22/2011	2.7977	12	2011	12/1/2011	4.64	12	2011	12/1/2011	4.46	12	2011
9	2011	9/23/2011	2.9002	12	2011	12/2/2011	4.52	12	2011	12/2/2011	4.36	12	2011
9	2011	9/26/2011	2.9925	12	2011	12/5/2011	4.53	12	2011	12/5/2011	4.37	12	2011
9	2011	9/27/2011	3.0693	12	2011	12/6/2011	4.58	12	2011	12/6/2011	4.44	12	2011
9	2011	9/28/2011	3.07	12	2011	12/7/2011	4.52	12	2011	12/7/2011	4.37	12	2011
9	2011	9/29/2011	3.0537	12	2011	12/8/2011	4.48	12	2011	12/8/2011	4.35	12	2011
9	2011	9/30/2011	2.9134	12	2011	12/9/2011	4.58	12	2011	12/9/2011	4.45	12	2011
10	2011	10/3/2011	2.7246	12	2011	12/12/2011	4.53	12	2011	12/12/2011	4.4	12	2011
10	2011	10/4/2011	2.8039	12	2011	12/13/2011	4.49	12	2011	12/13/2011	4.35	12	2011
10	2011	10/5/2011	2.8519	12	2011	12/14/2011	4.39	12	2011	12/14/2011	4.26	12	2011
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10	2011	10/12/2011	3.1964	12	2011	12/21/2011	4.49	12	2011	12/21/2011	4.35	12	2011
10	2011	10/13/2011	3.1508	12	2011	12/22/2011	4.46	12	2011	12/22/2011	4.33	12	2011
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10	2011	10/19/2011	3.1756	12	2011	12/29/2011	4.39	12	2011	12/29/2011	4.26	12	2011
10	2011	10/20/2011	3.216	12	2011	12/30/2011	4.36	12	2011	12/30/2011	4.24	12	2011
10	2011	10/21/2011	3.2638	1	2012	1/3/2012	4.46	1	2012	1/3/2012	4.34	1	2012
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10	2011	10/31/2011	3.1307	1	2012	1/11/2012	4.4	1	2012	1/11/2012	4.28	1	2012
11	2011	11/1/2011	2.9998	1	2012	1/12/2012	4.42	1	2012	1/12/2012	4.3	1	2012
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11	2011	11/3/2011	3.1216	1	2012	1/17/2012	4.33	1	2012	1/17/2012	4.21	1	2012
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11	2011	11/7/2011	3.0997	1	2012	1/19/2012	4.45	1	2012	1/19/2012	4.34	1	2012
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11	2011	11/9/2011	3.028	1	2012	1/23/2012	4.55	1	2012	1/23/2012	4.45	1	2012
11	2011	11/10/2011	3.1063	1	2012	1/24/2012	4.56	1	2012	1/24/2012	4.45	1	2012
11	2011	11/11/2011	3.13	1	2012	1/25/2012	4.55	1	2012	1/25/2012	4.44	1	2012
11	2011	11/14/2011	3.1057	1	2012	1/26/2012	4.49	1	2012	1/26/2012	4.38	1	2012
11	2011	11/15/2011	3.0841	1	2012	1/27/2012	4.45	1	2012	1/27/2012	4.35	1	2012
11	2011	11/16/2011	3.0302	1	2012	1/30/2012	4.37	1	2012	1/30/2012	4.27	1	2012
11	2011	11/17/2011	2.9809	1	2012	1/31/2012	4.32	1	2012	1/31/2012	4.22	1	2012
11	2011	11/18/2011	2.9941	2	2012	2/1/2012	4.39	2	2012	2/1/2012	4.29	2	2012
11	2011	11/21/2011	2.9437	2	2012	2/2/2012	4.37	2	2012	2/2/2012	4.29	2	2012
11	2011	11/22/2011	2.8803	2	2012	2/3/2012	4.5	2	2012	2/3/2012	4.42	2	2012
11	2011	11/23/2011	2.8343	2	2012	2/6/2012	4.42	2	2012	2/6/2012	4.36	2	2012
11	2011	11/24/2011	2.8343	2	2012	2/7/2012	4.47	2	2012	2/7/2012	4.4	2	2012
11	2011	11/25/2011	2.9191	2	2012	2/8/2012	4.46	2	2012	2/8/2012	4.4	2	2012
11	2011	11/28/2011	2.929	2	2012	2/9/2012	4.5	2	2012	2/9/2012	4.45	2	2012
11	2011	11/29/2011	2.9567	2	2012	2/10/2012	4.42	2	2012	2/10/2012	4.37	2	2012
11	2011	11/30/2011	3.0554	2	2012	2/13/2012	4.46	2	2012	2/13/2012	4.4	2	2012
12	2011	12/1/2011	3.0912	2	2012	2/14/2012	4.37	2	2012	2/14/2012	4.32	2	2012
12	2011	12/2/2011	3.0237	2	2012	2/15/2012	4.4	2	2012	2/15/2012	4.34	2	2012
12	2011	12/5/2011	3.0277	2	2012	2/16/2012	4.45	2	2012	2/16/2012	4.39	2	2012
12	2011	12/6/2011	3.0984	2	2012	2/17/2012	4.46	2	2012	2/17/2012	4.4	2	2012
12	2011	12/7/2011	3.0617	2	2012	2/21/2012	4.49	2	2012	2/21/2012	4.43	2	2012
12	2011	12/8/2011	2.997	2	2012	2/22/2012	4.44	2	2012	2/22/2012	4.39	2	2012
12	2011	12/9/2011	3.1072	2	2012	2/23/2012	4.42	2	2012	2/23/2012	4.36	2	2012
12	2011	12/12/2011	3.0505	2	2012	2/24/2012	4.39	2	2012	2/24/2012	4.33	2	2012
12	2011	12/13/2011	3.0111	2	2012	2/27/2012	4.33	2	2012	2/27/2012	4.27	2	2012
12	2011	12/14/2011	2.9028	2	2012	2/28/2012	4.34	2	2012	2/28/2012	4.28	2	2012
12	2011	12/15/2011	2.9173	2	2012	2/29/2012	4.37	2	2012	2/29/2012	4.3	2	2012
12	2011	12/16/2011	2.8511	3	2012	3/1/2012	4.43	3	2012	3/1/2012	4.36	3	2012
12	2011	12/19/2011	2.7861	3	2012	3/2/2012	4.38	3	2012	3/2/2012	4.32	3	2012
12	2011	12/20/2011	2.9264	3	2012	3/5/2012	4.41	3	2012	3/5/2012	4.34	3	2012
12	2011	12/21/2011	3.0008	3	2012	3/6/2012	4.35	3	2012	3/6/2012	4.28	3	2012
12	2011	12/22/2011	2.9805	3	2012	3/7/2012	4.4	3	2012	3/7/2012	4.32	3	2012
12	2011	12/23/2011	3.0568	3	2012	3/8/2012	4.44	3	2012	3/8/2012	4.38	3	2012

12	2011	12/26/2011	3.0568	3	2012	3/9/2012	4.46	3	2012	3/9/2012	4.39	3	2012
12	2011	12/27/2011	3.0314	3	2012	3/12/2012	4.44	3	2012	3/12/2012	4.37	3	2012
12	2011	12/28/2011	2.9202	3	2012	3/13/2012	4.52	3	2012	3/13/2012	4.44	3	2012
12	2011	12/29/2011	2.9025	3	2012	3/14/2012	4.67	3	2012	3/14/2012	4.6	3	2012
12	2011	12/30/2011	2.8941	3	2012	3/15/2012	4.67	3	2012	3/15/2012	4.6	3	2012
1	2012	1/2/2012	2.8941	3	2012	3/16/2012	4.67	3	2012	3/16/2012	4.6	3	2012
1	2012	1/3/2012	2.9812	3	2012	3/19/2012	4.74	3	2012	3/19/2012	4.67	3	2012
1	2012	1/4/2012	3.0274	3	2012	3/20/2012	4.71	3	2012	3/20/2012	4.65	3	2012
1	2012	1/5/2012	3.0607	3	2012	3/21/2012	4.63	3	2012	3/21/2012	4.57	3	2012
1	2012	1/6/2012	3.0156	3	2012	3/22/2012	4.62	3	2012	3/22/2012	4.56	3	2012
1	2012	1/9/2012	3.0266	3	2012	3/23/2012	4.57	3	2012	3/23/2012	4.51	3	2012
1	2012	1/10/2012	3.0242	3	2012	3/26/2012	4.59	3	2012	3/26/2012	4.52	3	2012
1	2012	1/11/2012	2.9632	3	2012	3/27/2012	4.56	3	2012	3/27/2012	4.49	3	2012
1	2012	1/12/2012	2.971	3	2012	3/28/2012	4.57	3	2012	3/28/2012	4.5	3	2012
1	2012	1/13/2012	2.91	3	2012	3/29/2012	4.54	3	2012	3/29/2012	4.47	3	2012
1	2012	1/16/2012	2.91	3	2012	3/30/2012	4.61	3	2012	3/30/2012	4.54	3	2012
1	2012	1/17/2012	2.8985	4	2012	4/2/2012	4.61	4	2012	4/2/2012	4.53	4	2012
1	2012	1/18/2012	2.9562	4	2012	4/3/2012	4.67	4	2012	4/3/2012	4.6	4	2012
1	2012	1/19/2012	3.0416	4	2012	4/4/2012	4.64	4	2012	4/4/2012	4.57	4	2012
1	2012	1/20/2012	3.0998	4	2012	4/5/2012	4.59	4	2012	4/5/2012	4.52	4	2012
1	2012	1/23/2012	3.1297	4	2012	4/6/2012	4.51	4	2012	4/6/2012	4.44	4	2012
1	2012	1/24/2012	3.1492	4	2012	4/9/2012	4.48	4	2012	4/9/2012	4.4	4	2012
1	2012	1/25/2012	3.1484	4	2012	4/10/2012	4.45	4	2012	4/10/2012	4.36	4	2012
1	2012	1/26/2012	3.0902	4	2012	4/11/2012	4.5	4	2012	4/11/2012	4.41	4	2012
1	2012	1/27/2012	3.0574	4	2012	4/12/2012	4.52	4	2012	4/12/2012	4.43	4	2012
1	2012	1/30/2012	2.9989	4	2012	4/13/2012	4.46	4	2012	4/13/2012	4.37	4	2012
1	2012	1/31/2012	2.9375	4	2012	4/16/2012	4.43	4	2012	4/16/2012	4.33	4	2012
2	2012	2/1/2012	2.9919	4	2012	4/17/2012	4.47	4	2012	4/17/2012	4.37	4	2012
2	2012	2/2/2012	3.0028	4	2012	4/18/2012	4.44	4	2012	4/18/2012	4.35	4	2012
2	2012	2/3/2012	3.1192	4	2012	4/19/2012	4.43	4	2012	4/19/2012	4.33	4	2012
2	2012	2/6/2012	3.0966	4	2012	4/20/2012	4.45	4	2012	4/20/2012	4.35	4	2012
2	2012	2/7/2012	3.1435	4	2012	4/23/2012	4.41	4	2012	4/23/2012	4.3	4	2012
2	2012	2/8/2012	3.1509	4	2012	4/24/2012	4.45	4	2012	4/24/2012	4.33	4	2012
2	2012	2/9/2012	3.1803	4	2012	4/25/2012	4.47	4	2012	4/25/2012	4.36	4	2012
2	2012	2/10/2012	3.1404	4	2012	4/26/2012	4.46	4	2012	4/26/2012	4.35	4	2012
2	2012	2/13/2012	3.1202	4	2012	4/27/2012	4.44	4	2012	4/27/2012	4.33	4	2012
2	2012	2/14/2012	3.0873	4	2012	4/30/2012	4.44	4	2012	4/30/2012	4.33	4	2012
2	2012	2/15/2012	3.0897	5	2012	5/1/2012	4.49	5	2012	5/1/2012	4.38	5	2012
2	2012	2/16/2012	3.1387	5	2012	5/2/2012	4.44	5	2012	5/2/2012	4.33	5	2012
2	2012	2/17/2012	3.1476	5	2012	5/3/2012	4.44	5	2012	5/3/2012	4.33	5	2012
2	2012	2/20/2012	3.1476	5	2012	5/4/2012	4.4	5	2012	5/4/2012	4.29	5	2012
2	2012	2/21/2012	3.209	5	2012	5/7/2012	4.39	5	2012	5/7/2012	4.28	5	2012

2	2012	2/22/2012	3.1476	5	2012	5/8/2012	4.36	5	2012	5/8/2012	4.24	5	2012
2	2012	2/23/2012	3.1387	5	2012	5/9/2012	4.38	5	2012	5/9/2012	4.26	5	2012
2	2012	2/24/2012	3.0992	5	2012	5/10/2012	4.39	5	2012	5/10/2012	4.27	5	2012
2	2012	2/27/2012	3.0475	5	2012	5/11/2012	4.34	5	2012	5/11/2012	4.22	5	2012
2	2012	2/28/2012	3.0729	5	2012	5/14/2012	4.29	5	2012	5/14/2012	4.16	5	2012
2	2012	2/29/2012	3.0848	5	2012	5/15/2012	4.28	5	2012	5/15/2012	4.16	5	2012
3	2012	3/1/2012	3.1476	5	2012	5/16/2012	4.27	5	2012	5/16/2012	4.16	5	2012
3	2012	3/2/2012	3.1024	5	2012	5/17/2012	4.2	5	2012	5/17/2012	4.07	5	2012
3	2012	3/5/2012	3.15	5	2012	5/18/2012	4.23	5	2012	5/18/2012	4.08	5	2012
3	2012	3/6/2012	3.0736	5	2012	5/21/2012	4.25	5	2012	5/21/2012	4.12	5	2012
3	2012	3/7/2012	3.1233	5	2012	5/22/2012	4.37	5	2012	5/22/2012	4.23	5	2012
3	2012	3/8/2012	3.1745	5	2012	5/23/2012	4.29	5	2012	5/23/2012	4.14	5	2012
3	2012	3/9/2012	3.1778	5	2012	5/24/2012	4.35	5	2012	5/24/2012	4.2	5	2012
3	2012	3/12/2012	3.1712	5	2012	5/25/2012	4.35	5	2012	5/25/2012	4.2	5	2012
3	2012	3/13/2012	3.2663	5	2012	5/29/2012	4.34	5	2012	5/29/2012	4.2	5	2012
3	2012	3/14/2012	3.4009	5	2012	5/30/2012	4.24	5	2012	5/30/2012	4.08	5	2012
3	2012	3/15/2012	3.4148	5	2012	5/31/2012	4.2	5	2012	5/31/2012	4.04	5	2012
3	2012	3/16/2012	3.4061	6	2012	6/1/2012	4.09	6	2012	6/1/2012	3.92	6	2012
3	2012	3/19/2012	3.4779	6	2012	6/4/2012	4.14	6	2012	6/4/2012	3.97	6	2012
3	2012	3/20/2012	3.4454	6	2012	6/5/2012	4.18	6	2012	6/5/2012	4.03	6	2012
3	2012	3/21/2012	3.3837	6	2012	6/6/2012	4.28	6	2012	6/6/2012	4.13	6	2012
3	2012	3/22/2012	3.3596	6	2012	6/7/2012	4.3	6	2012	6/7/2012	4.16	6	2012
3	2012	3/23/2012	3.3051	6	2012	6/8/2012	4.3	6	2012	6/8/2012	4.16	6	2012
3	2012	3/26/2012	3.3391	6	2012	6/11/2012	4.26	6	2012	6/11/2012	4.11	6	2012
3	2012	3/27/2012	3.2975	6	2012	6/12/2012	4.31	6	2012	6/12/2012	4.16	6	2012
3	2012	3/28/2012	3.3102	6	2012	6/13/2012	4.25	6	2012	6/13/2012	4.11	6	2012
3	2012	3/29/2012	3.2731	6	2012	6/14/2012	4.24	6	2012	6/14/2012	4.1	6	2012
3	2012	3/30/2012	3.3358	6	2012	6/15/2012	4.23	6	2012	6/15/2012	4.08	6	2012
4	2012	4/2/2012	3.3281	6	2012	6/18/2012	4.22	6	2012	6/18/2012	4.07	6	2012
4	2012	4/3/2012	3.4404	6	2012	6/19/2012	4.25	6	2012	6/19/2012	4.12	6	2012
4	2012	4/4/2012	3.3572	6	2012	6/20/2012	4.23	6	2012	6/20/2012	4.1	6	2012
4	2012	4/5/2012	3.3265	6	2012	6/21/2012	4.19	6	2012	6/21/2012	4.05	6	2012
4	2012	4/6/2012	3.2157	6	2012	6/22/2012	4.25	6	2012	6/22/2012	4.13	6	2012
4	2012	4/9/2012	3.1959	6	2012	6/25/2012	4.18	6	2012	6/25/2012	4.05	6	2012
4	2012	4/10/2012	3.1281	6	2012	6/26/2012	4.2	6	2012	6/26/2012	4.06	6	2012
4	2012	4/11/2012	3.1959	6	2012	6/27/2012	4.19	6	2012	6/27/2012	4.06	6	2012
4	2012	4/12/2012	3.2116	6	2012	6/28/2012	4.16	6	2012	6/28/2012	4.03	6	2012
4	2012	4/13/2012	3.1273	6	2012	6/29/2012	4.25	6	2012	6/29/2012	4.13	6	2012
4	2012	4/16/2012	3.1305										
4	2012	4/17/2012	3.1411										
4	2012	4/18/2012	3.1265										
4	2012	4/19/2012	3.1208										

4	2012	4/20/2012	3.124
4	2012	4/23/2012	3.0846
4	2012	4/24/2012	3.1281
4	2012	4/25/2012	3.1476
4	2012	4/26/2012	3.1176
4	2012	4/27/2012	3.1224
4	2012	4/30/2012	3.1111
5	2012	5/1/2012	3.146
5	2012	5/2/2012	3.1159
5	2012	5/3/2012	3.1184
5	2012	5/4/2012	3.0709
5	2012	5/7/2012	3.0598
5	2012	5/8/2012	3.0336
5	2012	5/9/2012	3.0249
5	2012	5/10/2012	3.0407
5	2012	5/11/2012	3.0103
5	2012	5/14/2012	2.9199
5	2012	5/15/2012	2.9168
5	2012	5/16/2012	2.8989
5	2012	5/17/2012	2.7869
5	2012	5/18/2012	2.8064
5	2012	5/21/2012	2.8094
5	2012	5/22/2012	2.8665
5	2012	5/23/2012	2.8155
5	2012	5/24/2012	2.8719
5	2012	5/25/2012	2.8412
5	2012	5/28/2012	2.8412
5	2012	5/29/2012	2.8473
5	2012	5/30/2012	2.7137
5	2012	5/31/2012	2.6421
6	2012	6/1/2012	2.5194
6	2012	6/4/2012	2.5652
6	2012	6/5/2012	2.642
6	2012	6/6/2012	2.738
6	2012	6/7/2012	2.7402
6	2012	6/8/2012	2.7454
6	2012	6/11/2012	2.7083
6	2012	6/12/2012	2.7693
6	2012	6/13/2012	2.7083
6	2012	6/14/2012	2.7409
6	2012	6/15/2012	2.684
6	2012	6/18/2012	2.6606

6	2012	6/19/2012	2.7333
6	2012	6/20/2012	2.7356
6	2012	6/21/2012	2.6868
6	2012	6/22/2012	2.7616
6	2012	6/25/2012	2.6765
6	2012	6/26/2012	2.7
6	2012	6/27/2012	2.6918
6	2012	6/28/2012	2.6757
6	2012	6/29/2012	2.7533

Public Utility Bonds (Baa-Rated)				30-Year	Average	Public Utility Bonds		Credit Spreads	
Date	Yield			T-Bonds	Corporate	A-rated	Baa-Rated	A-rated	Baa-Rated
1/2/2007	6.15	1	2007	4.85	5.92	5.96	6.16	1.11	1.31
1/3/2007	6.1	2	2007	4.82	5.88	5.90	6.10	1.08	1.28
1/4/2007	6.06	3	2007	4.72	5.84	5.85	6.10	1.13	1.38
1/5/2007	6.07	4	2007	4.86	5.99	5.97	6.24	1.10	1.37
1/8/2007	6.07	5	2007	4.90	6.00	5.99	6.23	1.08	1.33
1/9/2007	6.07	6	2007	5.21	6.32	6.30	6.54	1.10	1.34
1/10/2007	6.09	7	2007	5.10	6.26	6.25	6.49	1.15	1.39
1/11/2007	6.14	8	2007	4.94	6.26	6.24	6.51	1.30	1.57
1/12/2007	6.17	9	2007	4.79	6.21	6.18	6.45	1.39	1.66
1/16/2007	6.15	10	2007	4.78	6.12	6.11	6.36	1.33	1.58
1/17/2007	6.19	11	2007	4.52	5.97	5.97	6.27	1.45	1.75
1/18/2007	6.15	12	2007	4.53	6.15	6.16	6.51	1.63	1.98
1/19/2007	6.16								
1/22/2007	6.14	1	2008	4.33	6.02	6.02	6.35	1.68	2.01
1/23/2007	6.19	2	2008	4.51	6.24	6.21	6.60	1.70	2.08
1/24/2007	6.2	3	2008	4.38	6.23	6.21	6.68	1.83	2.30
1/25/2007	6.25	4	2008	4.44	6.29	6.29	6.81	1.85	2.37
1/26/2007	6.26	5	2008	4.60	6.31	6.28	6.79	1.68	2.20
1/29/2007	6.27	6	2008	4.68	6.43	6.38	6.93	1.70	2.24
1/30/2007	6.26	7	2008	4.56	6.44	6.40	6.97	1.84	2.41
1/31/2007	6.22	8	2008	4.50	6.42	6.37	6.98	1.87	2.48
2/1/2007	6.23	9	2008	4.27	6.50	6.49	7.15	2.22	2.88
2/2/2007	6.22	10	2008	4.16	7.56	7.56	8.58	3.40	4.42
2/5/2007	6.19	11	2008	3.98	7.65	7.60	8.98	3.62	5.00
2/6/2007	6.15	12	2008	2.85	6.71	6.52	8.11	3.68	5.27
2/7/2007	6.12								
2/8/2007	6.11	1	2009	3.10	6.59	6.39	7.90	3.29	4.80
2/9/2007	6.16	2	2009	3.59	6.64	6.30	7.74	2.71	4.15
2/12/2007	6.17	3	2009	3.64	6.84	6.42	8.00	2.79	4.36
2/13/2007	6.19	4	2009	3.76	6.85	6.48	8.03	2.73	4.27
2/14/2007	6.11	5	2009	4.24	6.79	6.49	7.76	2.25	3.52
2/15/2007	6.08	6	2009	4.51	6.52	6.20	7.30	1.69	2.79
2/16/2007	6.07	7	2009	4.40	6.17	5.97	6.87	1.56	2.47
2/20/2007	6.05	8	2009	4.37	5.83	5.71	6.36	1.34	1.99
2/21/2007	6.06	9	2009	4.19	5.61	5.53	6.12	1.34	1.93
2/22/2007	6.09	10	2009	4.19	5.63	5.55	6.14	1.36	1.95
2/23/2007	6.04	11	2009	4.31	5.68	5.63	6.17	1.32	1.86
2/26/2007	6	12	2009	4.50	5.78	5.79	6.26	1.29	1.76
2/27/2007	5.91								
2/28/2007	6.01	1	2010	4.60	5.76	5.77	6.16	1.17	1.55

3/1/2007	6.02	2	2010	4.62	5.86	5.87	6.25	1.25	1.63
3/2/2007	6	3	2010	4.65	5.81	5.84	6.22	1.20	1.58
3/5/2007	6.02	4	2010	4.69	5.80	5.81	6.19	1.12	1.50
3/6/2007	6.02	5	2010	4.28	5.52	5.50	5.97	1.22	1.69
3/7/2007	6	6	2010	4.12	5.52	5.46	6.18	1.34	2.06
3/8/2007	6.02	7	2010	3.99	5.32	5.26	5.98	1.27	1.99
3/9/2007	6.09	8	2010	3.80	5.05	5.01	5.55	1.21	1.75
3/12/2007	6.05	9	2010	3.77	5.05	5.01	5.53	1.23	1.76
3/13/2007	6.03	10	2010	3.87	5.15	5.10	5.62	1.24	1.75
3/14/2007	6.08	11	2010	4.19	5.37	5.37	5.85	1.18	1.66
3/15/2007	6.08	12	2010	4.42	5.55	5.56	6.04	1.14	1.62
3/16/2007	6.09								
3/19/2007	6.11	1	2011	4.52	5.56	5.57	6.06	1.05	1.54
3/20/2007	6.1	2	2011	4.65	5.66	5.68	6.10	1.03	1.45
3/21/2007	6.09	3	2011	4.51	5.55	5.56	5.97	1.05	1.46
3/22/2007	6.18	4	2011	4.50	5.56	5.55	5.98	1.05	1.48
3/23/2007	6.2	5	2011	4.29	5.33	5.32	5.74	1.03	1.45
3/26/2007	6.18	6	2011	4.23	5.30	5.26	5.67	1.03	1.44
3/27/2007	6.21	7	2011	4.28	5.30	5.27	5.70	0.99	1.42
3/28/2007	6.23	8	2011	3.65	4.79	4.69	5.22	1.04	1.57
3/29/2007	6.22	9	2011	3.18	4.60	4.48	5.11	1.30	1.93
3/30/2007	6.25	10	2011	3.12	4.60	4.52	5.24	1.39	2.12
4/2/2007	6.23	11	2011	3.01	4.39	4.25	4.93	1.24	1.92
4/3/2007	6.25	12	2011	2.99	4.47	4.33	5.07	1.35	2.08
4/4/2007	6.25								
4/5/2007	6.27	1	2012	3.01	4.45	4.34	5.06	1.32	2.05
4/6/2007	6.32	2	2012	3.11	4.42	4.36	5.02	1.25	1.91
4/9/2007	6.32	3	2012	3.28	4.54	4.48	5.13	1.20	1.85
4/10/2007	6.3	4	2012	3.18	4.49	4.40	5.11	1.21	1.93
4/11/2007	6.3	5	2012	2.92	4.33	4.20	4.97	1.28	2.04
4/12/2007	6.3	6	2012	2.70	4.22	4.08	4.91	1.39	2.21
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1/22/2010	6.04
1/25/2010	6.09
1/26/2010	6.12
1/27/2010	6.11
1/28/2010	6.13
1/29/2010	6.09
2/1/2010	6.14
2/2/2010	6.13
2/3/2010	6.21
2/4/2010	6.13
2/5/2010	6.1
2/8/2010	6.14
2/9/2010	6.2
2/10/2010	6.27
2/11/2010	6.32
2/12/2010	6.3
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2/17/2010	6.37
2/18/2010	6.43
2/19/2010	6.36
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2/24/2010	6.27
2/25/2010	6.21
2/26/2010	6.17
3/1/2010	6.2
3/2/2010	6.21
3/3/2010	6.21
3/4/2010	6.17
3/5/2010	6.25
3/8/2010	6.26

3/9/2010	6.27
3/10/2010	6.27
3/11/2010	6.24
3/12/2010	6.21
3/15/2010	6.22
3/16/2010	6.17
3/17/2010	6.14
3/18/2010	6.16
3/19/2010	6.16
3/22/2010	6.12
3/23/2010	6.14
3/24/2010	6.26
3/25/2010	6.32
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4/6/2010	6.37
4/7/2010	6.26
4/8/2010	6.28
4/9/2010	6.26
4/12/2010	6.21
4/13/2010	6.17
4/14/2010	6.22
4/15/2010	6.22
4/16/2010	6.17
4/19/2010	6.19
4/20/2010	6.16
4/21/2010	6.09
4/22/2010	6.11
4/23/2010	6.14
4/26/2010	6.14
4/27/2010	6.03
4/28/2010	6.1
4/29/2010	6.05
4/30/2010	5.98
5/3/2010	6.01
5/4/2010	5.92
5/5/2010	5.89

5/6/2010	5.71
5/7/2010	5.88
5/10/2010	6.01
5/11/2010	6.05
5/12/2010	6.1
5/13/2010	6.08
5/14/2010	5.95
5/17/2010	5.99
5/18/2010	5.93
5/19/2010	5.93
5/20/2010	5.9
5/21/2010	5.87
5/24/2010	5.93
5/25/2010	5.91
5/26/2010	6.01
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5/28/2010	6.16
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6/7/2010	6.13
6/8/2010	6.12
6/9/2010	6.16
6/10/2010	6.28
6/11/2010	6.24
6/14/2010	6.29
6/15/2010	6.32
6/16/2010	6.27
6/17/2010	6.19
6/18/2010	6.23
6/21/2010	6.24
6/22/2010	6.18
6/23/2010	6.14
6/24/2010	6.17
6/25/2010	6.15
6/28/2010	6.1
6/29/2010	6.04
6/30/2010	6
7/1/2010	5.96
7/2/2010	6.02
7/6/2010	5.98

7/7/2010	6.05
7/8/2010	6.09
7/9/2010	6.13
7/12/2010	6.12
7/13/2010	6.17
7/14/2010	6.08
7/15/2010	6
7/16/2010	5.97
7/19/2010	6
7/20/2010	5.92
7/21/2010	5.83
7/22/2010	5.87
7/23/2010	5.92
7/26/2010	5.9
7/27/2010	5.94
7/28/2010	5.91
7/29/2010	5.9
7/30/2010	5.8
8/2/2010	5.8
8/3/2010	5.77
8/4/2010	5.79
8/5/2010	5.77
8/6/2010	5.7
8/9/2010	5.71
8/10/2010	5.73
8/11/2010	5.64
8/12/2010	5.66
8/13/2010	5.6
8/16/2010	5.45
8/17/2010	5.49
8/18/2010	5.46
8/19/2010	5.39
8/20/2010	5.4
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8/24/2010	5.32
8/25/2010	5.35
8/26/2010	5.33
8/27/2010	5.5
8/30/2010	5.41
8/31/2010	5.36
9/1/2010	5.47
9/2/2010	5.52

9/3/2010	5.57
9/7/2010	5.44
9/8/2010	5.49
9/9/2010	5.61
9/10/2010	5.64
9/13/2010	5.59
9/14/2010	5.52
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9/16/2010	5.66
9/17/2010	5.65
9/20/2010	5.61
9/21/2010	5.53
9/22/2010	5.48
9/23/2010	5.48
9/24/2010	5.54
9/27/2010	5.45
9/28/2010	5.41
9/29/2010	5.45
9/30/2010	5.45
10/1/2010	5.48
10/4/2010	5.48
10/5/2010	5.5
10/6/2010	5.43
10/7/2010	5.48
10/8/2010	5.52
10/12/2010	5.56
10/13/2010	5.59
10/14/2010	5.67
10/15/2010	5.77
10/18/2010	5.7
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10/20/2010	5.65
10/21/2010	5.67
10/22/2010	5.67
10/25/2010	5.63
10/26/2010	5.71
10/27/2010	5.75
10/28/2010	5.77
10/29/2010	5.7
11/1/2010	5.72
11/2/2010	5.64
11/3/2010	5.75

11/4/2010	5.72
11/5/2010	5.8
11/8/2010	5.81
11/9/2010	5.92
11/10/2010	5.9
11/11/2010	5.91
11/12/2010	5.94
11/15/2010	6.05
11/16/2010	5.93
11/17/2010	5.95
11/18/2010	5.95
11/19/2010	5.92
11/22/2010	5.86
11/23/2010	5.82
11/24/2010	5.95
11/26/2010	5.86
11/29/2010	5.79
11/30/2010	5.75
12/1/2010	5.89
12/2/2010	5.91
12/3/2010	5.96
12/6/2010	5.89
12/7/2010	6.07
12/8/2010	6.1
12/9/2010	6.03
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12/13/2010	6.03
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12/15/2010	6.22
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12/21/2010	6.02
12/22/2010	6.04
12/23/2010	6.06
12/27/2010	6.01
12/28/2010	6.13
12/29/2010	6
12/30/2010	6.02
12/31/2010	5.93
1/3/2011	6.01
1/4/2011	6.05

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1/6/2011	6.09
1/7/2011	6.05
1/10/2011	6.04
1/11/2011	6.03
1/12/2011	6.05
1/13/2011	6.03
1/14/2011	6.06
1/18/2011	6.08
1/19/2011	6.04
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2/10/2011	6.21
2/11/2011	6.17
2/14/2011	6.12
2/15/2011	6.1
2/16/2011	6.1
2/17/2011	6.09
2/18/2011	6.13
2/22/2011	6.04
2/23/2011	6.04
2/24/2011	5.99
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2/28/2011	5.92
3/1/2011	5.93
3/2/2011	5.98
3/3/2011	6.07
3/4/2011	6.03
3/7/2011	6.04

3/8/2011	6.09
3/9/2011	6.02
3/10/2011	5.96
3/11/2011	5.96
3/14/2011	5.94
3/15/2011	5.95
3/16/2011	5.86
3/17/2011	5.9
3/18/2011	5.91
3/21/2011	5.92
3/22/2011	5.92
3/23/2011	5.93
3/24/2011	5.95
3/25/2011	5.98
3/28/2011	5.97
3/29/2011	6.02
3/30/2011	6
3/31/2011	5.99
4/1/2011	5.98
4/4/2011	5.98
4/5/2011	6
4/6/2011	6.07
4/7/2011	6.11
4/8/2011	6.11
4/11/2011	6.11
4/12/2011	6.06
4/13/2011	6.03
4/14/2011	6.02
4/15/2011	5.95
4/18/2011	5.94
4/19/2011	5.91
4/20/2011	5.94
4/21/2011	5.94
4/25/2011	5.93
4/26/2011	5.87
4/27/2011	5.92
4/28/2011	5.89
4/29/2011	5.86
5/2/2011	5.85
5/3/2011	5.82
5/4/2011	5.78
5/5/2011	5.74

5/6/2011	5.75
5/9/2011	5.77
5/10/2011	5.8
5/11/2011	5.76
5/12/2011	5.82
5/13/2011	5.78
5/16/2011	5.72
5/17/2011	5.67
5/18/2011	5.73
5/19/2011	5.74
5/20/2011	5.74
5/23/2011	5.71
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5/25/2011	5.73
5/26/2011	5.66
5/27/2011	5.67
5/31/2011	5.64
6/1/2011	5.58
6/2/2011	5.68
6/3/2011	5.66
6/6/2011	5.69
6/7/2011	5.69
6/8/2011	5.64
6/9/2011	5.66
6/10/2011	5.62
6/13/2011	5.64
6/14/2011	5.74
6/15/2011	5.63
6/16/2011	5.6
6/17/2011	5.65
6/20/2011	5.65
6/21/2011	5.66
6/22/2011	5.67
6/23/2011	5.6
6/24/2011	5.62
6/27/2011	5.73
6/28/2011	5.77
6/29/2011	5.81
6/30/2011	5.82
7/1/2011	5.84
7/5/2011	5.83
7/6/2011	5.79

7/7/2011	5.81
7/8/2011	5.71
7/11/2011	5.65
7/12/2011	5.63
7/13/2011	5.62
7/14/2011	5.68
7/15/2011	5.68
7/18/2011	5.72
7/19/2011	5.63
7/20/2011	5.7
7/21/2011	5.74
7/22/2011	5.67
7/25/2011	5.73
7/26/2011	5.68
7/27/2011	5.68
7/28/2011	5.66
7/29/2011	5.54
8/1/2011	5.48
8/2/2011	5.34
8/3/2011	5.29
8/4/2011	5.15
8/5/2011	5.25
8/8/2011	5.16
8/9/2011	5.08
8/10/2011	5.06
8/11/2011	5.33
8/12/2011	5.23
8/15/2011	5.29
8/16/2011	5.22
8/17/2011	5.15
8/18/2011	5.05
8/19/2011	5.01
8/22/2011	5.06
8/23/2011	5.17
8/24/2011	5.32
8/25/2011	5.31
8/26/2011	5.26
8/29/2011	5.35
8/30/2011	5.25
8/31/2011	5.33
9/1/2011	5.23
9/2/2011	5.04

9/6/2011	5.01
9/7/2011	5.11
9/8/2011	5.07
9/9/2011	5.04
9/12/2011	5.04
9/13/2011	5.14
9/14/2011	5.16
9/15/2011	5.24
9/16/2011	5.23
9/19/2011	5.13
9/20/2011	5.16
9/21/2011	5
9/22/2011	4.9
9/23/2011	5
9/26/2011	5.13
9/27/2011	5.25
9/28/2011	5.24
9/29/2011	5.15
9/30/2011	5.07
10/3/2011	4.92
10/4/2011	4.93
10/5/2011	5.08
10/6/2011	5.16
10/7/2011	5.23
10/11/2011	5.33
10/12/2011	5.43
10/13/2011	5.35
10/14/2011	5.4
10/17/2011	5.32
10/18/2011	5.3
10/19/2011	5.27
10/20/2011	5.28
10/21/2011	5.33
10/24/2011	5.35
10/25/2011	5.2
10/26/2011	5.25
10/27/2011	5.37
10/28/2011	5.24
10/31/2011	5.08
11/1/2011	4.9
11/2/2011	4.92
11/3/2011	4.99

11/4/2011	4.97
11/7/2011	4.9
11/8/2011	4.99
11/9/2011	4.89
11/10/2011	4.98
11/14/2011	4.96
11/15/2011	4.99
11/16/2011	4.96
11/17/2011	4.88
11/18/2011	4.92
11/21/2011	4.88
11/22/2011	4.87
11/23/2011	4.8
11/25/2011	4.9
11/28/2011	4.91
11/29/2011	4.96
11/30/2011	5.07
12/1/2011	5.17
12/2/2011	5.09
12/5/2011	5.11
12/6/2011	5.17
12/7/2011	5.1
12/8/2011	5.08
12/9/2011	5.17
12/12/2011	5.12
12/13/2011	5.07
12/14/2011	4.98
12/15/2011	5
12/16/2011	4.93
12/19/2011	4.9
12/20/2011	5.03
12/21/2011	5.11
12/22/2011	5.09
12/23/2011	5.18
12/27/2011	5.15
12/28/2011	5.01
12/29/2011	5.02
12/30/2011	4.99
1/3/2012	5.1
1/4/2012	5.15
1/5/2012	5.14
1/6/2012	5.1

1/9/2012	5.12
1/10/2012	5.09
1/11/2012	5.03
1/12/2012	5.03
1/13/2012	4.95
1/17/2012	4.93
1/18/2012	5
1/19/2012	5.04
1/20/2012	5.1
1/23/2012	5.15
1/24/2012	5.16
1/25/2012	5.15
1/26/2012	5.08
1/27/2012	5.04
1/30/2012	4.95
1/31/2012	4.91
2/1/2012	4.97
2/2/2012	4.96
2/3/2012	5.09
2/6/2012	5.01
2/7/2012	5.06
2/8/2012	5.05
2/9/2012	5.08
2/10/2012	5
2/13/2012	5.05
2/14/2012	4.97
2/15/2012	5
2/16/2012	5.05
2/17/2012	5.07
2/21/2012	5.1
2/22/2012	5.06
2/23/2012	5.03
2/24/2012	5
2/27/2012	4.94
2/28/2012	4.96
2/29/2012	4.98
3/1/2012	5.05
3/2/2012	5.01
3/5/2012	5.03
3/6/2012	4.95
3/7/2012	4.98
3/8/2012	5.03

3/9/2012	5.04
3/12/2012	5.02
3/13/2012	5.11
3/14/2012	5.25
3/15/2012	5.25
3/16/2012	5.25
3/19/2012	5.32
3/20/2012	5.29
3/21/2012	5.21
3/22/2012	5.2
3/23/2012	5.15
3/26/2012	5.16
3/27/2012	5.13
3/28/2012	5.13
3/29/2012	5.1
3/30/2012	5.2
4/2/2012	5.22
4/3/2012	5.29
4/4/2012	5.26
4/5/2012	5.2
4/6/2012	5.13
4/9/2012	5.1
4/10/2012	5.07
4/11/2012	5.12
4/12/2012	5.14
4/13/2012	5.08
4/16/2012	5.05
4/17/2012	5.09
4/18/2012	5.07
4/19/2012	5.05
4/20/2012	5.07
4/23/2012	5.03
4/24/2012	5.07
4/25/2012	5.09
4/26/2012	5.08
4/27/2012	5.06
4/30/2012	5.06
5/1/2012	5.11
5/2/2012	5.07
5/3/2012	5.07
5/4/2012	5.03
5/7/2012	5.02

5/8/2012	4.98
5/9/2012	5
5/10/2012	5.01
5/11/2012	4.96
5/14/2012	4.9
5/15/2012	4.89
5/16/2012	4.9
5/17/2012	4.81
5/18/2012	4.85
5/21/2012	4.86
5/22/2012	5.02
5/23/2012	4.94
5/24/2012	5.02
5/25/2012	5.02
5/29/2012	5.01
5/30/2012	4.9
5/31/2012	4.87
6/1/2012	4.75
6/4/2012	4.78
6/5/2012	4.83
6/6/2012	4.94
6/7/2012	4.96
6/8/2012	4.97
6/11/2012	4.94
6/12/2012	4.98
6/13/2012	4.92
6/14/2012	4.92
6/15/2012	4.9
6/18/2012	4.9
6/19/2012	4.94
6/20/2012	4.93
6/21/2012	4.89
6/22/2012	4.96
6/25/2012	4.89
6/26/2012	4.91
6/27/2012	4.91
6/28/2012	4.88
6/29/2012	4.99

Institution Name	Ticker	Period Ended (mm/dd/yyyy)	Total Assets (Reported) *($000)*	Energy Operating Revenue (Reported) *($000)*	Reported Net Operating Income (Reported) *($000)*
AGL Resources Inc.	GAS	12/31/2011	13,913,000	2,338,000	440,000
Atmos Energy Corporation	ATO	9/30/2011	7,282,871	4,347,634	441,899
Laclede Group, Inc. (The)	LG	9/30/2011	1,783,082	1,603,307	118,247
New Jersey Resources Corporation	NJR	9/30/2011	2,649,444	3,009,209	143,001
Northwest Natural Gas Company	NWN	12/31/2011	2,746,574	848,796	144,845
Piedmont Natural Gas Company, Inc.	PNY	10/31/2011	3,242,541	1,433,905	143,011
South Jersey Industries, Inc.	SJI	12/31/2011	2,247,510	828,560	121,607
Southwest Gas Corporation	SWX	12/31/2011	4,276,007	1,887,188	250,080
MDU Resources Group, Inc.	MDU	12/31/2011	6,556,125	4,050,492	406,367

Source: SNL Financial

	GAS				ATO				LG				NJR		
	Low	High			Low	High			Low	High			Low	High	
Jan-12	40.64	42.88		Jan-12	31.94	33.83		Jan-12	39.91	41.93		Jan-12	46.82	50.28	
Feb-12	39.44	42.00		Feb-12	30.68	33.05		Feb-12	40.67	43.00		Feb-12	46.63	49.66	
Mar-12	38.42	40.14		Mar-12	30.39	31.60		Mar-12	38.58	41.46		Mar-12	43.86	47.03	
Apr-12	37.75	39.75		Apr-12	30.80	32.65		Apr-12	38.45	39.98		Apr-12	42.06	45.50	
May-12	36.59	40.29		May-12	32.10	33.93		May-12	37.70	40.39		May-12	41.47	44.38	
Jun-12	36.72	39.32		Jun-12	32.52	35.77		Jun-12	36.53	39.86		Jun-12	41.11	44.37	
	38.26	40.73	39.50		31.41	33.47	32.44		38.64	41.10	39.87		43.66	46.87	45.26

GAS			ATO			LG			NJR		
Date	Low	High	Date	Low	High	Date	Low	High	Date	Low	High
1/3/2012	41.88	42.88	1/3/2012	33.06	33.83	1/3/2012	40.45	41.18	1/3/2012	49.08	50.28
1/4/2012	41.60	42.17	1/4/2012	32.98	33.48	1/4/2012	40.37	41.02	1/4/2012	49.19	49.76
1/5/2012	41.17	41.89	1/5/2012	32.47	33.01	1/5/2012	40.18	40.82	1/5/2012	48.69	49.12
1/6/2012	41.13	41.95	1/6/2012	32.63	32.95	1/6/2012	40.25	40.69	1/6/2012	48.73	49.38
1/9/2012	40.80	41.35	1/9/2012	32.27	32.83	1/9/2012	40.00	40.40	1/9/2012	48.67	49.45
1/10/2012	41.01	41.50	1/10/2012	32.25	32.60	1/10/2012	40.22	40.50	1/10/2012	48.86	49.50
1/11/2012	41.01	41.38	1/11/2012	32.16	32.56	1/11/2012	40.11	40.44	1/11/2012	48.34	48.71
1/12/2012	40.98	41.42	1/12/2012	32.27	32.61	1/12/2012	40.01	40.34	1/12/2012	48.09	48.76
1/13/2012	40.64	41.30	1/13/2012	32.05	32.56	1/13/2012	39.91	40.26	1/13/2012	47.35	48.32
1/17/2012	41.37	41.94	1/17/2012	32.14	32.70	1/17/2012	40.20	40.50	1/17/2012	47.90	48.42
1/18/2012	41.25	41.87	1/18/2012	32.17	32.49	1/18/2012	40.01	40.41	1/18/2012	47.69	48.17
1/19/2012	41.26	41.92	1/19/2012	32.07	32.58	1/19/2012	40.15	40.46	1/19/2012	47.53	48.25
1/20/2012	41.35	42.05	1/20/2012	32.15	32.66	1/20/2012	40.06	40.60	1/20/2012	47.52	47.89
1/23/2012	41.61	42.24	1/23/2012	32.44	32.93	1/23/2012	40.26	40.82	1/23/2012	47.61	48.26
1/24/2012	41.23	41.79	1/24/2012	32.15	32.54	1/24/2012	40.19	40.79	1/24/2012	47.35	48.04
1/25/2012	41.00	42.02	1/25/2012	31.94	32.64	1/25/2012	40.29	41.00	1/25/2012	47.19	48.21
1/26/2012	41.68	42.28	1/26/2012	32.58	33.04	1/26/2012	40.73	41.91	1/26/2012	48.34	48.95
1/27/2012	41.47	42.34	1/27/2012	32.29	32.97	1/27/2012	40.88	41.93	1/27/2012	47.68	48.86
1/30/2012	41.22	41.62	1/30/2012	32.07	32.32	1/30/2012	41.31	41.79	1/30/2012	46.82	47.72
1/31/2012	41.10	41.58	1/31/2012	32.07	32.47	1/31/2012	41.41	41.75	1/31/2012	46.85	47.85
2/1/2012	41.42	41.85	2/1/2012	32.41	32.68	2/1/2012	41.72	42.68	2/1/2012	47.39	48.10
2/2/2012	41.55	41.86	2/2/2012	32.45	32.88	2/2/2012	42.32	42.76	2/2/2012	47.86	48.48
2/3/2012	41.43	42.00	2/3/2012	32.67	33.02	2/3/2012	42.64	43.00	2/3/2012	48.61	49.07
2/6/2012	41.25	41.52	2/6/2012	32.40	32.81	2/6/2012	42.25	42.67	2/6/2012	48.46	48.97
2/7/2012	41.01	41.87	2/7/2012	32.45	33.05	2/7/2012	42.35	42.84	2/7/2012	48.67	49.66
2/8/2012	41.32	41.86	2/8/2012	32.00	32.77	2/8/2012	42.30	42.78	2/8/2012	48.12	49.34
2/9/2012	41.56	41.90	2/9/2012	32.00	32.66	2/9/2012	42.20	42.62	2/9/2012	48.17	49.05

2/10/2012	41.18	41.56	2/10/2012	31.51	32.05	2/10/2012	41.86	42.30	2/10/2012	47.07	48.04
2/13/2012	41.20	41.91	2/13/2012	31.51	32.15	2/13/2012	41.93	42.33	2/13/2012	47.27	47.99
2/14/2012	40.83	41.38	2/14/2012	31.43	31.88	2/14/2012	41.62	42.00	2/14/2012	47.04	47.72
2/15/2012	40.62	41.23	2/15/2012	31.28	31.73	2/15/2012	41.26	42.00	2/15/2012	46.81	47.65
2/16/2012	40.87	41.32	2/16/2012	31.41	31.98	2/16/2012	41.49	42.20	2/16/2012	46.92	48.46
2/17/2012	41.15	41.42	2/17/2012	31.50	32.08	2/17/2012	41.88	42.19	2/17/2012	47.55	48.45
2/21/2012	41.06	41.74	2/21/2012	31.71	32.16	2/21/2012	41.64	42.31	2/21/2012	47.45	48.10
2/22/2012	40.00	41.49	2/22/2012	31.78	32.23	2/22/2012	41.63	42.10	2/22/2012	47.05	47.77
2/23/2012	40.79	41.48	2/23/2012	31.68	32.11	2/23/2012	41.78	42.24	2/23/2012	47.17	47.83
2/24/2012	40.27	41.43	2/24/2012	31.68	32.01	2/24/2012	41.76	42.21	2/24/2012	47.55	48.13
2/27/2012	39.96	40.46	2/27/2012	31.22	31.65	2/27/2012	41.51	42.04	2/27/2012	46.90	47.55
2/28/2012	39.50	40.46	2/28/2012	30.72	31.46	2/28/2012	40.67	42.28	2/28/2012	46.63	47.26
2/29/2012	39.44	40.09	2/29/2012	30.68	31.23	2/29/2012	40.83	41.83	2/29/2012	46.64	47.29
3/1/2012	39.54	40.06	3/1/2012	30.71	31.09	3/1/2012	40.70	41.46	3/1/2012	46.30	47.03
3/2/2012	39.15	39.62	3/2/2012	30.76	31.06	3/2/2012	40.19	40.91	3/2/2012	45.72	46.34
3/5/2012	39.17	39.81	3/5/2012	30.71	31.23	3/5/2012	40.10	41.35	3/5/2012	45.61	46.38
3/6/2012	39.22	39.61	3/6/2012	30.65	31.07	3/6/2012	40.68	41.19	3/6/2012	45.65	46.17
3/7/2012	39.23	39.78	3/7/2012	30.52	30.90	3/7/2012	40.60	40.98	3/7/2012	45.35	45.89
3/8/2012	39.10	39.56	3/8/2012	30.57	31.06	3/8/2012	40.06	40.71	3/8/2012	45.31	45.94
3/9/2012	39.01	39.49	3/9/2012	30.89	31.28	3/9/2012	40.43	41.23	3/9/2012	45.46	46.36
3/12/2012	39.38	39.65	3/12/2012	31.11	31.35	3/12/2012	40.86	41.20	3/12/2012	45.43	45.90
3/13/2012	39.62	40.08	3/13/2012	31.15	31.46	3/13/2012	40.84	41.31	3/13/2012	44.87	45.61
3/14/2012	39.65	40.14	3/14/2012	31.05	31.53	3/14/2012	40.22	41.24	3/14/2012	44.52	45.44
3/15/2012	39.09	39.76	3/15/2012	30.73	31.16	3/15/2012	39.79	40.47	3/15/2012	44.24	44.92
3/16/2012	39.06	39.68	3/16/2012	30.66	30.90	3/16/2012	39.67	40.27	3/16/2012	44.34	44.77
3/19/2012	38.68	39.21	3/19/2012	30.58	31.04	3/19/2012	39.60	40.14	3/19/2012	44.29	45.00
3/20/2012	38.42	39.18	3/20/2012	30.56	30.90	3/20/2012	39.39	39.93	3/20/2012	44.17	44.67
3/21/2012	38.80	39.23	3/21/2012	30.42	30.73	3/21/2012	39.00	39.67	3/21/2012	44.11	44.58
3/22/2012	38.45	38.94	3/22/2012	30.39	30.62	3/22/2012	38.58	38.91	3/22/2012	43.86	44.28
3/23/2012	38.49	38.86	3/23/2012	30.44	30.80	3/23/2012	38.58	39.04	3/23/2012	44.12	44.66
3/26/2012	38.75	39.19	3/26/2012	30.88	31.19	3/26/2012	39.14	39.54	3/26/2012	44.61	45.40
3/27/2012	38.93	39.35	3/27/2012	30.87	31.21	3/27/2012	39.04	39.31	3/27/2012	45.01	45.30
3/28/2012	38.68	39.25	3/28/2012	30.74	31.20	3/28/2012	38.72	39.11	3/28/2012	44.36	45.06
3/29/2012	38.44	38.98	3/29/2012	30.53	31.22	3/29/2012	38.73	39.10	3/29/2012	44.28	44.75
3/30/2012	38.80	39.24	3/30/2012	31.14	31.60	3/30/2012	38.96	39.30	3/30/2012	44.52	45.05
4/2/2012	39.01	39.75	4/2/2012	31.28	31.95	4/2/2012	38.74	39.63	4/2/2012	44.36	45.26
4/3/2012	39.07	39.49	4/3/2012	31.45	31.82	4/3/2012	39.52	39.94	4/3/2012	44.97	45.50
4/4/2012	39.03	39.24	4/4/2012	31.41	31.75	4/4/2012	39.17	39.78	4/4/2012	44.03	44.87
4/5/2012	38.65	39.10	4/5/2012	31.27	31.76	4/5/2012	39.00	39.37	4/5/2012	43.45	44.07

4/9/2012	38.32	38.53	4/9/2012	30.95	31.26	4/9/2012	38.50	38.86	4/9/2012	42.94	43.35
4/10/2012	37.75	38.24	4/10/2012	30.80	31.17	4/10/2012	38.45	38.87	4/10/2012	42.14	43.07
4/11/2012	37.90	38.51	4/11/2012	30.86	31.24	4/11/2012	38.53	38.90	4/11/2012	42.11	42.75
4/12/2012	37.82	38.32	4/12/2012	30.82	31.17	4/12/2012	38.53	39.01	4/12/2012	42.12	42.78
4/13/2012	37.84	38.44	4/13/2012	30.90	31.37	4/13/2012	38.57	38.94	4/13/2012	42.21	42.89
4/16/2012	37.87	38.19	4/16/2012	30.90	31.56	4/16/2012	38.65	39.38	4/16/2012	42.34	42.91
4/17/2012	38.06	38.53	4/17/2012	31.31	31.87	4/17/2012	39.13	39.57	4/17/2012	42.68	43.22
4/18/2012	37.97	38.46	4/18/2012	31.31	31.71	4/18/2012	38.66	39.19	4/18/2012	42.09	42.89
4/19/2012	37.75	38.19	4/19/2012	31.09	31.54	4/19/2012	38.50	38.89	4/19/2012	42.06	42.78
4/20/2012	37.97	38.33	4/20/2012	31.65	32.12	4/20/2012	38.91	39.38	4/20/2012	42.83	44.15
4/23/2012	37.75	38.03	4/23/2012	31.56	31.85	4/23/2012	38.55	38.85	4/23/2012	42.55	43.00
4/24/2012	37.95	38.36	4/24/2012	31.63	32.00	4/24/2012	38.73	39.49	4/24/2012	42.66	43.08
4/25/2012	38.38	39.02	4/25/2012	32.05	32.31	4/25/2012	39.54	39.98	4/25/2012	42.93	43.36
4/26/2012	38.49	39.00	4/26/2012	32.10	32.36	4/26/2012	39.35	39.62	4/26/2012	42.79	43.08
4/27/2012	38.86	39.28	4/27/2012	32.10	32.47	4/27/2012	38.95	39.64	4/27/2012	42.82	43.21
4/30/2012	39.02	39.48	4/30/2012	32.32	32.65	4/30/2012	39.20	39.69	4/30/2012	42.85	43.34
5/1/2012	38.64	39.56	5/1/2012	32.59	33.15	5/1/2012	39.35	40.39	5/1/2012	43.03	43.91
5/2/2012	38.78	40.29	5/2/2012	32.32	32.89	5/2/2012	39.03	39.47	5/2/2012	42.76	43.23
5/3/2012	38.41	38.80	5/3/2012	32.34	32.96	5/3/2012	39.00	39.46	5/3/2012	42.75	43.56
5/4/2012	38.40	38.84	5/4/2012	32.22	32.70	5/4/2012	38.93	39.38	5/4/2012	42.79	43.55
5/7/2012	38.21	38.69	5/7/2012	32.10	32.49	5/7/2012	38.81	39.35	5/7/2012	42.65	43.31
5/8/2012	38.08	38.61	5/8/2012	32.17	32.71	5/8/2012	38.91	39.30	5/8/2012	42.94	43.84
5/9/2012	38.08	38.53	5/9/2012	32.36	33.20	5/9/2012	38.73	39.16	5/9/2012	43.07	43.65
5/10/2012	38.41	38.93	5/10/2012	32.70	33.02	5/10/2012	38.74	39.28	5/10/2012	43.45	44.12
5/11/2012	38.44	38.97	5/11/2012	32.62	33.15	5/11/2012	38.70	39.05	5/11/2012	43.42	44.05
5/14/2012	38.10	38.49	5/14/2012	32.24	32.77	5/14/2012	38.52	38.97	5/14/2012	42.82	43.34
5/15/2012	37.75	38.27	5/15/2012	32.57	33.07	5/15/2012	38.66	39.00	5/15/2012	42.92	44.19
5/16/2012	37.50	37.83	5/16/2012	32.64	32.95	5/16/2012	38.76	39.09	5/16/2012	43.63	44.14
5/17/2012	36.94	37.83	5/17/2012	33.10	33.93	5/17/2012	38.53	39.00	5/17/2012	43.49	44.38
5/18/2012	36.69	37.25	5/18/2012	32.61	33.30	5/18/2012	38.41	38.93	5/18/2012	42.82	43.79
5/21/2012	36.59	36.95	5/21/2012	32.32	32.80	5/21/2012	38.00	38.52	5/21/2012	42.55	43.00
5/22/2012	36.88	37.22	5/22/2012	32.74	33.15	5/22/2012	38.04	38.52	5/22/2012	42.32	42.81
5/23/2012	36.74	37.17	5/23/2012	32.20	32.71	5/23/2012	37.80	39.00	5/23/2012	41.47	42.47
5/24/2012	36.81	37.35	5/24/2012	32.30	32.91	5/24/2012	37.78	38.29	5/24/2012	41.68	42.63
5/25/2012	36.81	37.47	5/25/2012	32.57	32.94	5/25/2012	38.03	38.32	5/25/2012	42.45	42.76
5/29/2012	37.30	37.72	5/29/2012	32.68	33.00	5/29/2012	37.80	38.34	5/29/2012	42.41	42.87
5/30/2012	37.01	37.81	5/30/2012	32.44	32.91	5/30/2012	37.73	38.32	5/30/2012	41.79	42.51
5/31/2012	37.11	37.78	5/31/2012	32.54	33.30	5/31/2012	37.70	38.29	5/31/2012	41.76	42.30
6/1/2012	36.86	37.48	6/1/2012	32.52	33.23	6/1/2012	36.53	37.95	6/1/2012	41.20	41.99

6/4/2012	36.72	37.18	6/4/2012	32.92	33.23	6/4/2012	37.32	38.09	6/4/2012	41.37	41.85
6/5/2012	36.76	37.21	6/5/2012	33.01	33.38	6/5/2012	37.36	37.66	6/5/2012	41.11	42.05
6/6/2012	37.06	37.73	6/6/2012	33.28	33.85	6/6/2012	37.36	38.16	6/6/2012	41.76	42.82
6/7/2012	37.82	38.43	6/7/2012	33.70	34.05	6/7/2012	37.61	38.04	6/7/2012	42.70	43.25
6/8/2012	37.66	38.17	6/8/2012	33.48	33.99	6/8/2012	37.63	38.43	6/8/2012	42.12	43.77
6/11/2012	38.00	38.50	6/11/2012	33.77	34.23	6/11/2012	38.45	38.96	6/11/2012	43.15	43.92
6/12/2012	37.71	38.16	6/12/2012	33.61	34.00	6/12/2012	38.31	38.75	6/12/2012	42.93	43.79
6/13/2012	37.88	38.36	6/13/2012	33.70	34.11	6/13/2012	38.48	38.95	6/13/2012	42.81	43.71
6/14/2012	38.11	38.56	6/14/2012	34.01	34.37	6/14/2012	38.61	38.93	6/14/2012	43.07	43.54
6/15/2012	38.47	38.79	6/15/2012	34.26	34.64	6/15/2012	38.93	39.50	6/15/2012	43.40	44.37
6/18/2012	38.48	38.80	6/18/2012	34.13	34.64	6/18/2012	39.08	39.59	6/18/2012	43.59	44.02
6/19/2012	38.59	39.32	6/19/2012	34.38	34.76	6/19/2012	39.27	39.86	6/19/2012	43.71	44.10
6/20/2012	38.70	39.22	6/20/2012	33.96	34.50	6/20/2012	38.98	39.62	6/20/2012	43.17	43.79
6/21/2012	37.63	39.06	6/21/2012	33.74	34.30	6/21/2012	38.55	39.17	6/21/2012	42.45	43.22
6/22/2012	37.58	38.28	6/22/2012	33.82	34.11	6/22/2012	38.69	39.05	6/22/2012	42.33	42.71
6/25/2012	37.59	38.14	6/25/2012	33.49	33.81	6/25/2012	38.50	38.82	6/25/2012	41.94	42.52
6/26/2012	37.83	38.24	6/26/2012	33.57	33.86	6/26/2012	38.42	38.78	6/26/2012	41.78	42.46
6/27/2012	37.89	38.29	6/27/2012	33.73	34.35	6/27/2012	38.50	39.27	6/27/2012	41.75	43.05
6/28/2012	37.82	38.50	6/28/2012	34.07	34.86	6/28/2012	38.67	39.25	6/28/2012	42.43	43.08
6/29/2012	38.46	39.12	6/29/2012	34.69	35.77	6/29/2012	39.45	39.81	6/29/2012	43.22	43.71

Source: Bloomberg Professional

	NWN				PNY				SJI				SWX		
	Low	High			Low	High			Low	High			Low	High	
Jan-12	46.60	48.83		Jan-12	32.38	34.63		Jan-12	54.09	57.99		Jan-12	40.51	43.22	
Feb-12	45.74	49.49		Feb-12	32.25	34.00		Feb-12	51.91	56.15		Feb-12	41.50	42.98	
Mar-12	44.40	46.52		Mar-12	30.70	32.96		Mar-12	49.55	52.06		Mar-12	41.89	43.64	
Apr-12	43.90	46.08		Apr-12	29.05	31.61		Apr-12	47.42	51.03		Apr-12	40.76	43.52	
May-12	44.87	46.66		May-12	28.90	30.71		May-12	46.52	49.84		May-12	41.03	43.42	
Jun-12	45.50	48.56		Jun-12	29.71	33.03		Jun-12	47.46	51.90		Jun-12	39.46	44.64	
	45.17	47.69	46.43		30.50	32.82	31.66		49.49	53.16	51.33		40.86	43.57	42.21

NWN			PNY			SJI			SWX		
Date	Low	High	Date	Low	High	Date	Low	High	Date	Low	High
1/3/2012	47.47	48.83	1/3/2012	34.00	34.63	1/3/2012	56.61	57.99	1/3/2012	42.44	43.22
1/4/2012	47.55	48.15	1/4/2012	33.77	34.14	1/4/2012	56.58	57.00	1/4/2012	42.06	42.73
1/5/2012	46.91	47.89	1/5/2012	33.18	33.71	1/5/2012	55.95	57.00	1/5/2012	41.65	42.46
1/6/2012	47.11	47.77	1/6/2012	33.16	33.68	1/6/2012	55.97	56.80	1/6/2012	41.90	42.32
1/9/2012	46.83	47.57	1/9/2012	33.06	33.51	1/9/2012	55.39	56.35	1/9/2012	41.51	42.07
1/10/2012	47.13	47.58	1/10/2012	33.34	33.85	1/10/2012	55.94	56.43	1/10/2012	41.43	42.10
1/11/2012	47.05	47.55	1/11/2012	33.23	33.46	1/11/2012	55.72	56.10	1/11/2012	41.03	41.59
1/12/2012	47.01	47.52	1/12/2012	33.00	33.41	1/12/2012	55.30	55.91	1/12/2012	40.92	41.40
1/13/2012	46.74	47.17	1/13/2012	32.64	33.07	1/13/2012	54.92	55.49	1/13/2012	40.51	40.89
1/17/2012	47.04	47.69	1/17/2012	33.01	33.46	1/17/2012	55.44	56.01	1/17/2012	40.76	41.62
1/18/2012	46.68	47.25	1/18/2012	32.67	33.10	1/18/2012	54.84	55.53	1/18/2012	41.07	41.75
1/19/2012	46.87	47.25	1/19/2012	32.54	32.94	1/19/2012	54.19	55.08	1/19/2012	41.32	41.81
1/20/2012	46.79	47.36	1/20/2012	32.52	32.79	1/20/2012	54.49	54.88	1/20/2012	41.18	41.73
1/23/2012	46.96	47.37	1/23/2012	32.57	33.00	1/23/2012	54.67	55.40	1/23/2012	41.53	42.17
1/24/2012	46.82	47.20	1/24/2012	32.52	32.80	1/24/2012	54.55	54.92	1/24/2012	41.34	41.63
1/25/2012	46.60	47.39	1/25/2012	32.38	32.99	1/25/2012	54.27	54.84	1/25/2012	41.17	42.17
1/26/2012	47.36	48.46	1/26/2012	33.01	33.52	1/26/2012	54.55	55.32	1/26/2012	42.01	42.49
1/27/2012	47.38	47.99	1/27/2012	32.95	33.45	1/27/2012	54.73	55.34	1/27/2012	42.00	42.49
1/30/2012	46.97	47.54	1/30/2012	32.65	33.04	1/30/2012	54.09	54.65	1/30/2012	41.67	42.02
1/31/2012	47.18	47.71	1/31/2012	32.65	33.16	1/31/2012	54.10	55.08	1/31/2012	41.52	42.24
2/1/2012	47.57	48.55	2/1/2012	33.00	33.48	2/1/2012	54.68	55.21	2/1/2012	41.83	42.50
2/2/2012	48.32	48.75	2/2/2012	33.41	33.71	2/2/2012	54.68	55.17	2/2/2012	42.17	42.60
2/3/2012	48.80	49.49	2/3/2012	33.73	33.95	2/3/2012	55.56	56.15	2/3/2012	42.50	42.87
2/6/2012	48.88	49.29	2/6/2012	33.52	33.88	2/6/2012	55.16	55.68	2/6/2012	42.27	42.73
2/7/2012	48.71	49.37	2/7/2012	33.45	34.00	2/7/2012	55.10	55.74	2/7/2012	42.37	42.86
2/8/2012	48.37	48.99	2/8/2012	33.46	33.92	2/8/2012	54.73	55.63	2/8/2012	42.18	42.87
2/9/2012	48.14	48.83	2/9/2012	33.41	33.96	2/9/2012	54.78	55.35	2/9/2012	42.31	42.91

2/10/2012	47.69	48.14	2/10/2012	33.13	33.45	2/10/2012	54.00	54.65	2/10/2012	41.92	42.73
2/13/2012	47.89	48.28	2/13/2012	33.21	33.58	2/13/2012	54.08	54.68	2/13/2012	41.81	42.38
2/14/2012	47.31	48.03	2/14/2012	33.06	33.50	2/14/2012	53.89	54.42	2/14/2012	41.50	42.05
2/15/2012	47.22	47.99	2/15/2012	32.79	33.49	2/15/2012	53.47	54.50	2/15/2012	41.69	42.21
2/16/2012	47.52	48.41	2/16/2012	32.92	33.69	2/16/2012	53.58	54.78	2/16/2012	41.86	42.84
2/17/2012	48.15	48.69	2/17/2012	33.63	33.99	2/17/2012	54.54	55.16	2/17/2012	42.38	42.98
2/21/2012	47.96	48.63	2/21/2012	33.55	33.99	2/21/2012	54.25	54.84	2/21/2012	42.32	42.89
2/22/2012	47.80	48.46	2/22/2012	33.35	33.78	2/22/2012	54.02	54.52	2/22/2012	42.19	42.68
2/23/2012	48.04	48.72	2/23/2012	33.43	33.86	2/23/2012	54.11	54.72	2/23/2012	42.43	42.98
2/24/2012	48.04	48.68	2/24/2012	33.23	33.89	2/24/2012	54.14	54.78	2/24/2012	42.35	42.90
2/27/2012	47.60	48.14	2/27/2012	32.72	33.24	2/27/2012	53.71	54.49	2/27/2012	41.81	42.71
2/28/2012	46.13	47.80	2/28/2012	32.25	32.95	2/28/2012	52.41	53.90	2/28/2012	41.75	42.62
2/29/2012	45.74	47.05	2/29/2012	32.25	32.72	2/29/2012	51.91	54.40	2/29/2012	42.26	42.93
3/1/2012	45.28	46.31	3/1/2012	31.89	32.60	3/1/2012	50.76	51.95	3/1/2012	42.32	42.93
3/2/2012	45.14	45.82	3/2/2012	31.38	32.21	3/2/2012	50.49	51.74	3/2/2012	42.29	42.82
3/5/2012	45.00	46.11	3/5/2012	31.43	32.59	3/5/2012	50.54	51.94	3/5/2012	42.25	43.12
3/6/2012	45.22	45.78	3/6/2012	32.03	32.46	3/6/2012	51.27	51.83	3/6/2012	42.33	42.94
3/7/2012	45.18	45.93	3/7/2012	31.98	32.49	3/7/2012	50.74	51.36	3/7/2012	42.26	42.75
3/8/2012	45.29	45.79	3/8/2012	32.13	32.53	3/8/2012	50.79	51.44	3/8/2012	42.50	42.98
3/9/2012	45.48	46.32	3/9/2012	32.16	32.96	3/9/2012	51.13	52.00	3/9/2012	42.75	43.38
3/12/2012	45.77	46.33	3/12/2012	31.96	32.47	3/12/2012	51.36	52.00	3/12/2012	43.09	43.44
3/13/2012	45.96	46.43	3/13/2012	32.10	32.49	3/13/2012	51.37	52.06	3/13/2012	43.02	43.62
3/14/2012	45.81	46.52	3/14/2012	31.72	32.45	3/14/2012	51.05	51.97	3/14/2012	42.88	43.64
3/15/2012	45.29	46.02	3/15/2012	31.23	31.82	3/15/2012	50.44	51.13	3/15/2012	42.47	43.08
3/16/2012	45.26	45.79	3/16/2012	31.52	31.92	3/16/2012	50.84	51.19	3/16/2012	42.85	43.22
3/19/2012	45.12	45.68	3/19/2012	31.35	31.81	3/19/2012	50.51	51.18	3/19/2012	42.44	43.25
3/20/2012	44.87	45.42	3/20/2012	31.41	31.67	3/20/2012	50.54	51.10	3/20/2012	42.53	42.86
3/21/2012	44.72	45.18	3/21/2012	31.01	31.43	3/21/2012	50.46	50.97	3/21/2012	42.40	42.67
3/22/2012	44.40	44.89	3/22/2012	30.75	31.05	3/22/2012	50.00	50.72	3/22/2012	41.89	42.40
3/23/2012	44.66	45.25	3/23/2012	30.93	31.24	3/23/2012	50.19	50.78	3/23/2012	42.02	42.45
3/26/2012	45.32	45.73	3/26/2012	31.29	31.63	3/26/2012	50.95	51.48	3/26/2012	42.64	43.21
3/27/2012	45.40	45.72	3/27/2012	31.28	31.57	3/27/2012	50.72	51.24	3/27/2012	42.84	43.11
3/28/2012	45.01	45.67	3/28/2012	30.89	31.35	3/28/2012	49.84	50.90	3/28/2012	42.29	43.00
3/29/2012	44.87	45.45	3/29/2012	30.70	31.10	3/29/2012	49.55	50.25	3/29/2012	42.22	42.85
3/30/2012	45.38	45.69	3/30/2012	31.01	31.26	3/30/2012	50.03	50.40	3/30/2012	42.64	43.01
4/2/2012	45.02	45.93	4/2/2012	30.76	31.55	4/2/2012	49.73	50.70	4/2/2012	42.56	43.33
4/3/2012	45.40	46.08	4/3/2012	31.14	31.61	4/3/2012	50.11	51.03	4/3/2012	42.92	43.52
4/4/2012	45.34	45.82	4/4/2012	30.89	31.17	4/4/2012	49.36	50.00	4/4/2012	42.59	42.98
4/5/2012	45.00	45.54	4/5/2012	30.58	31.09	4/5/2012	48.59	49.54	4/5/2012	42.30	42.66

4/9/2012	44.59	45.00	4/9/2012	30.24	30.59	4/9/2012	48.25	48.61	4/9/2012	41.92	42.28
4/10/2012	43.90	44.81	4/10/2012	29.59	30.26	4/10/2012	47.57	48.44	4/10/2012	41.43	42.05
4/11/2012	44.23	44.52	4/11/2012	29.50	29.95	4/11/2012	47.55	48.19	4/11/2012	41.29	41.74
4/12/2012	44.27	44.85	4/12/2012	29.41	29.68	4/12/2012	47.69	48.24	4/12/2012	40.88	41.68
4/13/2012	44.06	44.70	4/13/2012	29.30	29.89	4/13/2012	47.59	48.21	4/13/2012	41.12	41.53
4/16/2012	44.16	44.67	4/16/2012	29.25	29.64	4/16/2012	47.42	48.19	4/16/2012	41.05	41.53
4/17/2012	44.62	45.17	4/17/2012	29.66	30.06	4/17/2012	48.10	48.83	4/17/2012	41.49	42.21
4/18/2012	44.30	44.80	4/18/2012	29.50	29.83	4/18/2012	48.27	48.63	4/18/2012	41.27	41.84
4/19/2012	44.00	44.61	4/19/2012	29.05	29.60	4/19/2012	47.58	48.44	4/19/2012	40.76	41.41
4/20/2012	44.43	45.01	4/20/2012	29.59	29.87	4/20/2012	48.23	48.81	4/20/2012	41.38	41.83
4/23/2012	44.01	44.45	4/23/2012	29.23	29.47	4/23/2012	47.48	48.18	4/23/2012	40.84	41.32
4/24/2012	44.21	45.06	4/24/2012	29.38	29.84	4/24/2012	47.75	48.41	4/24/2012	41.14	41.54
4/25/2012	45.16	45.49	4/25/2012	29.84	30.13	4/25/2012	48.45	48.95	4/25/2012	41.67	41.90
4/26/2012	44.61	45.35	4/26/2012	29.77	30.14	4/26/2012	48.54	49.09	4/26/2012	41.60	41.80
4/27/2012	45.16	45.77	4/27/2012	29.96	30.32	4/27/2012	48.72	49.19	4/27/2012	41.62	42.00
4/30/2012	45.46	45.82	4/30/2012	30.12	30.52	4/30/2012	48.74	49.34	4/30/2012	41.65	42.14
5/1/2012	45.49	46.33	5/1/2012	30.00	30.71	5/1/2012	48.94	49.84	5/1/2012	41.76	42.90
5/2/2012	45.16	45.74	5/2/2012	29.69	30.02	5/2/2012	48.34	49.02	5/2/2012	41.52	42.05
5/3/2012	45.24	45.95	5/3/2012	29.53	29.97	5/3/2012	48.21	48.86	5/3/2012	41.56	42.03
5/4/2012	44.87	45.52	5/4/2012	29.33	29.57	5/4/2012	47.84	48.29	5/4/2012	41.43	41.78
5/7/2012	45.01	46.66	5/7/2012	29.05	29.53	5/7/2012	47.17	48.05	5/7/2012	41.03	42.57
5/8/2012	45.85	46.63	5/8/2012	29.24	29.64	5/8/2012	47.03	47.86	5/8/2012	42.13	43.15
5/9/2012	45.88	46.45	5/9/2012	29.23	29.74	5/9/2012	47.23	48.00	5/9/2012	42.26	42.78
5/10/2012	46.09	46.59	5/10/2012	29.63	30.03	5/10/2012	47.79	48.40	5/10/2012	42.76	43.42
5/11/2012	45.84	46.39	5/11/2012	29.65	29.94	5/11/2012	47.73	48.08	5/11/2012	42.48	42.98
5/14/2012	45.37	45.90	5/14/2012	29.42	29.80	5/14/2012	47.20	47.73	5/14/2012	42.05	42.80
5/15/2012	45.69	46.19	5/15/2012	29.46	29.85	5/15/2012	47.11	47.51	5/15/2012	42.23	42.76
5/16/2012	45.76	46.08	5/16/2012	29.66	30.13	5/16/2012	47.50	47.83	5/16/2012	42.30	42.62
5/17/2012	45.55	46.15	5/17/2012	29.46	29.97	5/17/2012	47.45	47.87	5/17/2012	42.05	42.58
5/18/2012	45.35	45.88	5/18/2012	29.37	29.81	5/18/2012	47.25	47.82	5/18/2012	41.68	42.31
5/21/2012	45.56	46.16	5/21/2012	29.16	29.59	5/21/2012	47.22	47.68	5/21/2012	41.47	41.94
5/22/2012	45.65	46.17	5/22/2012	29.38	29.62	5/22/2012	47.23	47.70	5/22/2012	41.80	42.08
5/23/2012	45.31	46.08	5/23/2012	28.90	29.47	5/23/2012	46.52	47.55	5/23/2012	41.25	41.99
5/24/2012	45.55	46.32	5/24/2012	29.09	29.63	5/24/2012	46.76	47.43	5/24/2012	41.45	41.99
5/25/2012	46.05	46.45	5/25/2012	29.50	29.79	5/25/2012	47.25	47.60	5/25/2012	41.65	41.99
5/29/2012	45.88	46.42	5/29/2012	29.50	29.89	5/29/2012	47.42	47.98	5/29/2012	41.62	42.23
5/30/2012	45.92	46.49	5/30/2012	29.54	29.97	5/30/2012	47.49	47.96	5/30/2012	41.57	42.04
5/31/2012	45.92	46.66	5/31/2012	29.70	30.53	5/31/2012	47.54	48.67	5/31/2012	41.67	42.22
6/1/2012	45.50	46.16	6/1/2012	29.71	30.52	6/1/2012	47.46	49.05	6/1/2012	39.46	42.13

6/4/2012	45.67	46.10	6/4/2012	29.86	30.27	6/4/2012	48.62	49.03	6/4/2012	41.69	42.10
6/5/2012	45.71	46.51	6/5/2012	30.40	30.95	6/5/2012	48.65	49.47	6/5/2012	41.76	42.32
6/6/2012	46.35	46.72	6/6/2012	30.63	31.68	6/6/2012	49.31	50.43	6/6/2012	42.25	43.20
6/7/2012	46.63	47.15	6/7/2012	31.31	31.99	6/7/2012	50.04	50.49	6/7/2012	42.97	43.65
6/8/2012	46.51	47.31	6/8/2012	30.91	31.85	6/8/2012	49.92	50.66	6/8/2012	42.91	44.00
6/11/2012	46.88	47.69	6/11/2012	31.58	32.06	6/11/2012	50.14	51.05	6/11/2012	43.67	44.28
6/12/2012	46.52	47.06	6/12/2012	31.47	31.90	6/12/2012	49.79	50.56	6/12/2012	43.42	43.99
6/13/2012	46.75	47.41	6/13/2012	31.68	32.20	6/13/2012	49.91	50.84	6/13/2012	43.74	44.40
6/14/2012	46.89	47.47	6/14/2012	31.93	32.31	6/14/2012	50.25	50.84	6/14/2012	43.89	44.22
6/15/2012	47.19	47.83	6/15/2012	32.00	32.50	6/15/2012	50.63	51.39	6/15/2012	44.09	44.43
6/18/2012	47.21	47.87	6/18/2012	32.10	32.48	6/18/2012	50.49	51.05	6/18/2012	43.78	44.36
6/19/2012	47.22	47.94	6/19/2012	32.16	32.64	6/19/2012	50.48	51.29	6/19/2012	44.07	44.64
6/20/2012	47.23	47.77	6/20/2012	31.80	32.32	6/20/2012	50.02	50.82	6/20/2012	43.94	44.50
6/21/2012	47.34	47.68	6/21/2012	31.45	32.03	6/21/2012	49.70	50.27	6/21/2012	43.41	44.15
6/22/2012	47.60	48.19	6/22/2012	31.62	32.15	6/22/2012	49.72	50.49	6/22/2012	43.55	43.94
6/25/2012	47.62	48.04	6/25/2012	31.71	32.27	6/25/2012	49.78	50.29	6/25/2012	43.17	43.64
6/26/2012	47.69	48.04	6/26/2012	31.99	32.60	6/26/2012	50.03	50.62	6/26/2012	43.19	43.60
6/27/2012	47.88	48.50	6/27/2012	32.48	32.94	6/27/2012	50.39	50.89	6/27/2012	43.53	44.19
6/28/2012	47.40	48.37	6/28/2012	32.09	32.65	6/28/2012	50.01	51.02	6/28/2012	43.29	44.04
6/29/2012	47.30	48.56	6/29/2012	32.05	33.03	6/29/2012	50.72	51.90	6/29/2012	43.56	44.17

	GAS Dividend
Jan-12	1.80
Feb-12	1.80
Mar-12	1.80
Apr-12	1.80
May-12	1.84
Jun-12	1.84
	1.81

	ATO Dividend
Jan-12	1.38
Feb-12	1.38
Mar-12	1.38
Apr-12	1.38
May-12	1.38
Jun-12	1.38
	1.38

	LG Dividend
Jan-12	1.66
Feb-12	1.66
Mar-12	1.66
Apr-12	1.66
May-12	1.66
Jun-12	1.66
	1.66

	NJR Dividend
Jan-12	1.52
Feb-12	1.52
Mar-12	1.52
Apr-12	1.52
May-12	1.52
Jun-12	1.52
	1.52

GAS	
2/16/2011	0.45
5/11/2011	0.45
8/17/2011	0.45
11/16/2011	0.45
5/16/2012	0.46

ATO	
2/23/2011	0.34
5/23/2011	0.34
8/23/2011	0.34
11/22/2011	0.35
2/23/2012	0.35
5/23/2012	0.35

LG	
3/9/2011	0.41
6/8/2011	0.41
9/8/2011	0.41
12/8/2011	0.42
3/8/2012	0.42
6/7/2012	0.42

NJR	
3/11/2011	0.36
6/13/2011	0.36
9/13/2011	0.36
12/13/2011	0.38
3/13/2012	0.38
6/13/2012	0.38

Source: Bloomberg Professional

	NWN Dividend
Jan-12	1.78
Feb-12	1.78
Mar-12	1.78
Apr-12	1.78
May-12	1.78
Jun-12	1.78
	1.78

	PNY Dividend
Jan-12	1.16
Feb-12	1.16
Mar-12	1.20
Apr-12	1.20
May-12	1.20
Jun-12	1.20
	1.19

	SJI Dividend
Jan-12	1.61
Feb-12	1.61
Mar-12	1.61
Apr-12	1.61
May-12	1.61
Jun-12	1.61
	1.61

	SWX Dividend
Jan-12	1.06
Feb-12	1.06
Mar-12	1.06
Apr-12	1.06
May-12	1.18
Jun-12	1.18
	1.10

NWN	
1/27/2011	0.44
4/27/2011	0.44
7/27/2011	0.44
10/27/2011	0.45
1/27/2012	0.45
4/26/2012	0.45
7/27/2012	0.45

PNY	
3/23/2011	0.29
6/22/2011	0.29
9/21/2011	0.29
12/22/2011	0.29
3/21/2012	0.30
6/20/2012	0.30

SJI	
3/8/2011	0.37
6/8/2011	0.37
9/7/2011	0.37
12/7/2011	0.40
3/7/2012	0.40
6/7/2012	0.40
9/6/2012	0.40

SWX	
2/11/2011	0.25
5/12/2011	0.27
8/11/2011	0.27
11/10/2011	0.27
2/13/2012	0.27
5/11/2012	0.30
8/13/2012	0.30