

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE
STATE OF NORTH DAKOTA**

**PRE-FILED RESPONSIVE TESTIMONY
OF
GEORGE MATHAI, CPA**

**NDPSC FILE NO. PU-10-124
OAH FILE NO. 20100196**

OCTOBER 15, 2010

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**PRE-FILED RESPONSIVE TESTIMONY
OF
GEORGE MATHAI, CPA**

1 **I. INTRODUCTION**

2 **Q. WOULD YOU PLEASE STATE YOUR NAME?**

3 A. My name is George Mathai.

4 **Q. WHAT IS YOUR BUSINESS ADDRESS?**

5 A. My business address is 3608 NW 58th Street, Suite 100, Oklahoma City, OK
6 73112.

7 **Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

8 A. I am a utility regulatory consultant and Managing Principal of Mathai &
9 Associates Regulatory Consultants (MARC), LLC also known as MARC LLC.

10 **Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

11 A. I received a Bachelor of Science in Business Administration and Journalism at
12 Dallas Baptist University in 1974. In 1980, I received a Master of Public
13 Administration from New York University. I have been a Certified Public
14 Accountant since 1985. I have attended numerous seminars and workshops
15 related to different aspects of Public Utility Regulation for the last 30 years, in
16 addition to several Continuing Professional Education seminars related to the
17 accounting profession. For the last 28 years, I have been an active member of
18 the National Association of Regulatory Utility Commissions' Staff Subcommittees
19 on Accounting and Finance, Electric, Gas, and Transportation.

20 **Q. PLEASE DESCRIBE YOUR PAST REGULATORY POSITIONS AND
21 RESPONSIBILITIES.**

22 A. Prior to forming MARC LLC, I was an Executive Consultant with ERG Consulting
23 Group/Legend Consulting Group Limited ("the Consulting Group"). The
24 Consulting Group provides regulatory consulting, consulting engineering, and
25 management consulting services to regulatory agencies and utility companies,
26 including the Council of the City of New Orleans on rate and regulatory matters
27 associated with Entergy New Orleans, Inc., Entergy Louisiana, LLC and Entergy

1 Corporation and its operating subsidiaries. Prior to joining the Consulting Group,
2 from August 1980 until October 2007, I held several auditing and management
3 positions with the Oklahoma Corporation Commission ("OCC") Public Utility
4 Division ("PUD"). I started as an Auditor, but over the course of my 27 year
5 employ with the OCC, I managed every department of PUD at one time or
6 another and retired as the CPA/Chief of the Accounting and Financial Auditing
7 Department ("AFA") as well as the Administrator of the Oklahoma Universal
8 Service Fund ("OUSF") of PUD. In these positions, my responsibilities included
9 coordinating and managing the daily activities of the personnel auditing the rate
10 cases of energy, water and telephone utilities, reviewing the fuel procurement
11 and generating practices of the energy utilities, and processing the tariff change
12 applications of electric, gas, telephone, and water utilities. I also reviewed
13 contractual issues, marketing strategies, generation costs, and other related
14 issues of utilities. Since July 1997, my responsibilities also included the
15 administration of various Funds established in the Public Utility Division by the
16 Legislature.

17
18 I have sponsored expert testimony on behalf of the PUD Staff on all major
19 regulatory issues before the OCC, including issues related to overall revenue
20 requirements, cost of service, system cost allocations, jurisdictional cost
21 allocations, rate of return, fuel procurement and pricing, cost recovery of the
22 dismantled Black Fox Nuclear Project, settlement of gas take-or-pay contracts,
23 current and prepaid pension funding, the effects of the Tax Revision Act of 1986,
24 incremental cost recovery of storm damages, new generation and transmission
25 recovery mechanism (NGTR), alternative regulatory approaches in the
26 development of cost recovery for utilities, such as performance based rate
27 change mechanisms (PBRC), and regarding the OUSF and E911 Fund.

28 A summary of my educational background and professional experience is
29 provided in **Exhibit NDPSC-2**. Additionally, **Exhibit NDPSC-3** contains a non-
30 exclusive summary of my previous regulatory appearances.

31 **Q: WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD WITH THE**

1 **OKLAHOMA COMMISSION?**

2 A: From June 1988 through June 1990, I was the CPA/Manager of Rates and
3 Registration of the Transportation Division of the Commission. My
4 responsibilities in that role included managing three departments that performed
5 rate audits, complaint investigations, and motor carrier requirement functions.

6 **Q: WHAT OTHER EXPERIENCE DID YOU HAVE PRIOR TO JOINING OCC?**

7 A: Prior to joining the Commission in 1980, I worked approximately two years as an
8 Auditor/Management Specialist for the State of New York. Before that, I worked
9 eight years with various weekly and other periodic publications as Chief Editor
10 and Business Manager.

11 **Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY IN THIS**
12 **PROCEEDING?**

13 A. My testimony is submitted on behalf of the Staff or ("the Staff") of the North
14 Dakota Public Service Commission ("Commission" or "NDPSC").

15 **Q: MR. MATHAI, HAVE YOU TESTIFIED BEFORE NDPSC IN THE PAST?**

16 A: No. I have not previously testified before this Commission. However, based on
17 my many years of regulatory experience before other state and federal regulatory
18 commissions, I am requesting this Commission accept my credentials as an
19 expert witness.

20 **PURPOSE**

21
22 **Q: MR. MATHAI, WHAT ARE YOUR RESPONSIBILITIES IN CONNECTION WITH**
23 **THE MONTANA-DAKOTA UTILITIES CO. ("MDU") RATE INCREASE**
24 **APPLICATION, CASE NUMBER PU-10-124?**

25 A: On behalf of the Staff, it was my responsibility to conduct the financial review
26 related to the Proposed Rate increase filing by MDU based on a projected 2010
27 test year. Specifically, after detailed review and investigation of the information
28 in MDU's filing, I prepared the Staff's Revenue Requirement Exhibit; prepared or
29 supervised the preparation of Staff's work paper schedules; formulated in
30 consultation with NDPSC Staff various accounting and other policy issues to
31 recommend to the Commission; and prepared the Pre-Filed Responsive

1 Testimony regarding the jurisdictional Revenue Requirement of MDU in this
2 application. Additionally, Mr. Steve Goodner on behalf of MARC LLC will file
3 Fuel, Cost of Service, and Rate Design related testimony to support the position
4 of the Staff.

5 **Q: WOULD YOU INDICATE SPECIFICALLY WHICH SCHEDULES AND ISSUES**
6 **YOU ARE SPONSORING IN YOUR PRE-FILED RESPONSIVE TESTIMONY?**

7 A: Yes. I am sponsoring the Staff Accounting Exhibit which explains Staff's
8 recommended jurisdictional Revenue Requirement for MDU. In the area of
9 general rate base, I am specifically testifying to issues including Wind Energy
10 investments, proper levels of Plant-in-Service, Accumulated Depreciation,
11 Deferred Generation Cost Balance, Unamortized Loss on Debt Balance, and
12 Customer Deposits. In the area of Income Statement, I am providing testimony
13 specifically on issues including Wind Energy Expenses, proper expense levels of
14 Labor/Payroll Annualization, Pension Expenses including 401-K Program,
15 Bonuses and Commissions, Incentive Compensation, Medical Benefits,
16 Corporate Expenses, Aircraft Expenses, Transmission Expense (WAPA Fees),
17 Coyote and Big Stone Generation Maintenance Expense, Storm Damage
18 Normalization, Deferred Generation Costs, Amortization of Unamortized Loss on
19 Debt, Customer Deposit Interest Expense, and Interest Synchronization
20 Additionally, my Pre-filed Responsive Testimony addresses Staff's
21 recommendations related to the rate making treatment of Wind Energy Revenue
22 Requirement recovery.

23 24 **EXECUTIVE SUMMARY**

25
26 MDU requested initially a rate increase of \$15,394,000 which it amended to
27 \$13,300,000 on July 6, 2010. However, with a negotiated ROE Settlement, the
28 request was reduced to \$11,518,000. The Staff's detailed analysis of the books
29 and records of MDU calculates instead a Revenue Excess of \$2,804,000, after
30 removing the Wind Energy Revenue Requirement from base rates. **See**

31 **Schedule CV-3-1 (L&P)** The Staff recommends the Commission find there is no

1 need for more expensive wind energy. However if it finds otherwise, Staff
2 recommends to include only a portion of the North Dakota based wind energy
3 investment in a rider, outside of base rates. Staff is providing more detailed
4 explanation in the later part of my testimony.

5
6 **The following issues are the focus of my testimony:**

7 **Wind Investment Revenue Requirement:**

8
9 MDU has not demonstrated any need for the higher cost of wind energy for the
10 North Dakota customers. In fact, its recent resource plans have raised doubts
11 that question the prudence of these investments, as opposed to demonstrated
12 prudence. While MDU has submitted resource plans, such plans do not
13 thoroughly discuss enough alternative plans that very well may have been more
14 appropriate for North Dakota ratepayers. While North Dakota has an objective of
15 ten percent (10%) for renewable energy supply, this objective is not to be met
16 without weighing costs. MDU's Integrated Resource Plans' references and
17 statements support a conclusion that the wind investments are not least cost,
18 which brings in to question any conclusion of prudence.

19
20 Staff also understands that MDU's main reason for starting its wind projects was
21 to meet the Montana Legislative Mandate of 10% and 15% of its retail sales
22 (kWh's) from wind sources by 2010 and 2015, respectively. Supporting those
23 statements in MDU's Resource Plans are filings in Montana that retire the
24 Renewable Energy Credits generated by these wind farms.

25
26 MDU requested approximately 65% of its total wind energy to be allocated to
27 North Dakota jurisdiction, which translates to \$72 million in investments and
28 \$324,000 in expenses (after Production and ND Investment Tax Credits)
29 applicable to the three wind projects – Diamond Willow (1 & 2) and Cedar Hills
30 for a total Wind Revenue Requirement of \$10,547,551. See wind related
31 calculations on Schedule GM-4.1 It is Staff's opinion that since MDU has a

1 Montana Legislative Mandate regarding wind energy requirements, and MDU
2 has not established that current wind projects produce the least cost energy
3 available for North Dakota customers, all wind related revenue requirement be
4 excluded from base rates. Staff's recommendation will help MDU meet its
5 Montana mandate of 2010 and 2015 regarding wind energy.

6
7 **General Rate Base Issues:**

8 Staff has taken exception to certain items included by MDU in the Projected Rate
9 base. They include:

- 10 1. Plant In Service
- 11 2. Aircraft Plant-in Service
- 12 3. Accumulated Depreciation
- 13 4. Deferred Generation Cost Balance
- 14 5. Unamortized Loss On Debt Balance
- 15 6. Customer Deposit
- 16 7. Level of Wind Related Accumulated Deferred Income Tax (ADIT)

17
18 **General Income Statement Issues:**

19 Staff has taken exception to MDU's treatment of zeroing out both Sale for Resale
20 Revenues and Margin Sharing Adjustment. Staff has put back the test year level
21 Revenues and corresponding Fuel and Purchased Power expenses in the Cost
22 of Service. Any Sale for Resale Revenues above the included level should be
23 shared 90% by customers and 10% by stockholders. Such **additional** revenues
24 should be flowed to customers through Fuel and Purchased Power Tariff.

25
26 Staff has also taken exception to MDU's proposed levels of certain expenses
27 including:

- 28 1. Payroll Annualization
- 29 2. Bonuses and Commissions
- 30 3. Incentive Compensation
- 31 4. Aircraft expenses

- 1 5. Corporate Expenses
- 2 6. Transmission Charges -WAPA Fees
- 3 7. Coyote and Big Stone Generation Maintenance Expenses
- 4 8. Amortization of Deferred Generation Costs
- 5 9. Amortization of Loss on Debt and Storm Costs.

6 Some of these adjustments have increasing income effects and others have
7 decreasing income effects. Staff supports MDU's requested projected level of
8 Medical and other Employee Benefits Expense.

9

10 **GENERAL OBSERVATIONS AND RECOMMENDATIONS**

11

12 **1. Meeting Minimum Standard Filing Requirements (MSFR) for Rate Case**
13 **Filing and other Procedural Concerns.**

14 First of all, I want to thank the MDU Regulatory Staff for their cooperation to the
15 Staff while processing this Application. The following comments and suggestions
16 are made with positive intentions for the benefit of all stakeholders of MDU.

17

18 The Staff recommends to the Commission that it should establish through a
19 Rulemaking, a better **Minimum Standard Filing Requirement (MSFR)** for
20 utilities when they initiate a Rate Increase Filing. Staff's processing of MDU's
21 Rate Increase Application PU-10-124 revealed this case could have been
22 processed in a more timely and efficient way, if the filing itself was made to the
23 Commission under a better MSFR.

24

25 Also, as the main Staff witness in this case, based on my 30 plus years of
26 regulatory experience, and auditing of hundreds of Rate Cases of utilities ranging
27 from Class A to Class D, I believe a MSFR would avoid confusion as to the
28 expectations from each parties while processing a Rate Case. It also avoids
29 unnecessary delays and requests for information.

30

1 The challenges Staff faced in receiving the required information made meeting
2 audit goals and time deadlines very difficult. MDU filed its application with certain
3 major Statements, and a related Work Paper Schedule Binder as it deemed
4 necessary. As requested, it also provided the Staff an electronic disk with the
5 same work papers. However, the filed information did not contain adequate
6 details nor was it appropriately referenced or cross referenced in a way that
7 would enable an *experienced auditor* to review it in a timely and efficient manner.
8 There are very few Lead Summary Schedules with adequate explanation and in
9 most cases have no attached supporting schedules. Many of the supporting work
10 papers were not independently usable, as there was no audit trail to determine
11 how MDU arrived at the requested rate increase. Filed Work Paper Schedules
12 and Responses to our Data Requests were a mixture of three buckets. (1)
13 Certain Schedules and Data Request Responses showed total MDU amounts
14 without extracting North Dakota Jurisdictional amounts; (2) other schedules
15 showed total Electric Operations without showing the North Dakota jurisdictional
16 amounts; (3) and yet others showed amounts with North Dakota headings. The
17 inconsistent rendering of information, in combination with the automated way of
18 assigning and accounting for utility costs by MDU, made it very complex to trace
19 any given investment or expense back to an original invoice. As a result, Staff
20 had to issue repeated Data Requests before it could arrive at a reasonable
21 conclusion of any given issue.

22
23 On a going forward basis, it is important that the Commission, through its Rules,
24 establish upfront what is expected of a utility when it is requesting that its rates
25 be changed. Having a good MSFR is good for all stakeholders, including MDU,
26 its customers and the regulators.

27
28 Another major issue confronted by Staff is the limited time to finish the Rate
29 Case. Since there is no specific discovery turnaround time established by the
30 Commission, the default time by law is 30 days. Time is consumed appointing
31 experts and on procedural activities. Often Staff needs to issue several rounds

1 of discovery on the same issue before it can make a fair, just and reasonable
2 conclusion. An eight-month case completion deadline puts an undue burden on
3 the Staff. Therefore, it is recommended the Commission request legislation that
4 would extend the deadline for processing a Rate Increase Application to 12
5 months. It is also recommend that the Commission establish a rule requiring that
6 Discovery requests be answered within 10 business days as is common in other
7 jurisdictions. Increasing the time to process the case is very reasonable given
8 the existing practice of granting Interim Rates.

9
10 From a resource standpoint, it is believed that Staff is handicapped in its ability to
11 fully examine the issues that arise in a rate case. The funding allowance of
12 \$125,000 for expert witnesses, legal representation and the administrative costs
13 associated with processing a Rate Increase Application is not sufficient given the
14 size of the Commission's staff. Staff must deal with major issues that arise
15 during the course of a review. In this particular case, Staff was required to spend
16 many non-budgeted hours to obtain supporting documentation as well as
17 evaluating the wind energy related projects. MDU's record keeping was not in
18 tune with separating and calculating the standalone Revenue Requirement for
19 this type of investment. Staff issued several Discovery Requests and it took
20 many hours of review to arrive at a reasonable conclusion. This approach of
21 separating the cost elements was important as MDU had not sought a pre-
22 approval of construction of these projects. It would be very easy to spend the
23 entire consulting contract hours evaluating the wind projects alone. Based on my
24 experience, a good rate case investigation costs \$250,000 to \$1,000,000.
25 Additionally, the Commission should make provisions to compensate for the
26 review of additional high cost issues such as new generation, transmission or
27 other major issues.

28
29 **2. Evaluation of MDU's Accounting System and Jurisdictional Allocation**
30 **Process**

1 Staff's processing of MDU's Rate Increase Application PU-10-124 revealed that
2 an evaluation/study of MDU's accounting system should be conducted to
3 understand its adherence to the FERC system of accounting and cost allocation
4 process. The existing system had been in place for a long time and, as per
5 response to our inquiry, there has been no recent internal or external study done
6 or initiated by MDU to evaluate the appropriateness or usefulness of its
7 accounting system. Staff found it very difficult to trace amounts back to any
8 original source document to create a reasonable and manageable audit trail.
9 Most costs are automatically accounted for by the system based on the
10 previously set parameters. The Staff was not able to establish any type of easy
11 access to management reports that would help in its evaluation other than the
12 assertion by MDU that management heavily relies on the budget centers. Since
13 MDU is part of multiple jurisdictions and a sister company of regulated and
14 unregulated operations, the Commission should evaluate periodically MDU's
15 Jurisdictional Allocation Process. Staff's inquiry has revealed that no such
16 evaluation/study had been conducted recently.

17
18 During the processing of a Rate Increase Application, there is not enough time or
19 resources to concentrate on such crucial and unique issues as a company's
20 internal accounting process or detailed review of its jurisdictional allocation.
21 Therefore we recommend the Commission order a Management Audit of MDU.

22
23 **3. Corporate Allocation Methodology/Affiliate Transactions:**

24 Similarly, Staff proposes that the Commission order a comprehensive review of
25 MDU's Corporate Allocation Factor calculation methodology and its Affiliate
26 Transactions. Such review is beneficial to MDU's North Dakota customers to
27 insure they are not subsidizing any of the non-regulated or other-regulated
28 utilities. Regarding the Corporate Allocation, MDU is using an equity based
29 Corporate Allocation Factor. Based on responses to Staff's inquiry, MDU has not
30 conducted a recent study to evaluate the reasonableness of its methodology as
31 compared to other traditionally used studies by utilities and Commissions across

1 the nation like the Distringas Methodology or its derivations. Such methodologies
2 give broader assurance that established rates are fair, just, and reasonable and
3 do not disproportionately allocate corporate costs to its utility operations.
4 Alternative methodologies include a combination of (1) Total Assets less Cash
5 and Inter-Company receivables, (2) Net Revenues, (3) Payroll and (4) Earnings
6 before Interest, Taxes, Depreciation, and Amortization (EBITDA). Staff
7 recommends this issue be incorporated as a part of the Management Audit as
8 suggested above.
9

10 DETAILED TESTIMONY

11 STAFF'S OVERALL REVENUE REQUIREMENT

12
13 **Q: MR. MATHAI, PLEASE EXPLAIN THE OVERALL REVENUE REQUIREMENT**
14 **RECOMMENDED BY STAFF IN THIS CASE.**

15 **A:** Staff proposes a jurisdictional Revenue Excess of \$2,804,000 as shown in Staff
16 Revenue Requirement Calculation Schedule GM-3-1 (L-1). This finding of
17 Revenue Excess for MDU incorporates Staff's recommended 2010 projected
18 jurisdictional Rate Base of \$197,477,000 and projected 2010 jurisdictional
19 operating income of \$18,845,000 and rate of return of 8.679%. Refer to
20 Schedules GM-3-1-L-1, GM-3-2-M-1 and GM-3-3-N-1 Schedules for Staff
21 Accounting Exhibit

22 **Q: WHAT IS STAFF'S POSITION REGARDING INCLUSION OF KNOWN AND**
23 **MEASURABLE CHANGES FOR RATEMAKING PURPOSES?**

24 **A:** MDU proposed a projected 2010 test year. Staff used the latest information
25 based on the responses to over 150 Data Requests issued by Staff in order to
26 fairly evaluate MDU's rate increase application. It is a widely accepted utility
27 regulatory principle to set future rates based on future costs. In the current case,
28 MDU mainly used its 2009 booked amounts as the basis for its rate increase
29 request as for known and measurable changes to arrive at a 2010 test year.
30 Staff is in agreement with such an approach, as long as it is used and useful and
31 is reasonable in providing reliable electric service to the customers.

1
2 **Wind Energy Investment and Expense Issues**

3 **Q. MR. MATHAI, WHAT ARE YOUR RECOMMENDATIONS REGARDING THE**
4 **TREATMENT OF WIND ENERGY INVESTMENTS AND EXPENSES**
5 **PROPOSED BY MDU IN THIS FILING?**

6 A. MDU requested \$73,768,992 of Wind Investments related to the Diamond Willow
7 and Cedar Hills projects in the Rate base with a related Accumulated
8 Depreciation of \$2,351,993 (GM-4-1). The portion of these investments allocated
9 to North Dakota represents approximately 64.32% of the total wind energy
10 investments. The Staff also proposed an adjustment to increase the ADIT
11 balance by \$3,241,000, as agreed to by MDU due to an oversight in its
12 application. The application also includes O&M expenses of \$323,939 net of
13 Production Tax Credits and ND Investment Tax Credits. See Schedule GM-4-1
14 and GM-4-9 for details of the investments and expenses.

15 **Q: DO YOU AGREE WITH MDU'S ALLOCATION OF THE WIND PROJECTS TO**
16 **NORTH DAKOTA?**

17 A: No.

18 **Q: PLEASE EXPLAIN YOUR REASONS.**

19 A: Montana-Dakota is required to procure a minimum of 10% of its Montana retail
20 electric energy from eligible renewable resources pursuant to MONT. CODE
21 ANN. §69-3-2004 (2009). Montana law increases the requirement to 15% in
22 2015. Through comments in MDU Resource Plans, discovery, and use of REC's
23 in Montana, Staff has recognized that Diamond Willow was built to meet the
24 Montana mandate, not as a prudent investment for North Dakota ratepayers. So
25 Staff is supporting MDU's efforts to meet its requirement by excluding all
26 Montana wind related investments and expenses from the revenue requirement
27 calculation of this case.

28
29 Under existing Montana law, assuming Montana kWh sales of 700,394,000,
30 MDU must retire 70,039 renewable energy credits (REC's) for the year ending
31 2010. Diamond Willow 1 will produce approximately 66,620 REC's if it attains its

1 projected 39% capacity. Staff estimates that beginning in 2015, MDU will be
2 required to retire 115,994 REC's for its Montana operations. Assuming a 39%
3 capacity factor for both Diamond Willow projects, MDU will generate 102,492
4 REC's, a deficiency of 13,502 REC's even while allocating 100% of the Diamond
5 Willow projects to Montana.

6
7 With regard to Cedar Hills, MDU likewise has not met its burden of proof as to
8 whether the wind farm was necessary or in fact is a least cost alternative. Even if
9 Cedar Hills enjoyed a presumption of prudence (which it does not due to failing to
10 apply for Advanced Determination of Prudence), the Resource Plan¹ and
11 discovery in this case are sufficient to rebut any initial presumption of prudence
12 as a result of its North Dakota location.

13
14 **Q: DID MDU PROVIDE ANY EVIDENCE TO THIS COMMISSION ESTABLISHING**
15 **THE NEED FOR THE WIND ENERGY TO SERVE THE NORTH DAKOTA**
16 **CUSTOMERS?**

17 **A:** No. MDU has not demonstrated any need for the wind energy projects. In fact,
18 its recent integrated resource plans (IRP's) have raised doubts that question the
19 prudence of these investments instead of demonstrating prudence. The IRP's do
20 not discuss alternative energy plans compared to the wind farms, and raise
21 concerns about the prudence of such investments. While North Dakota has an
22 objective of ten percent (10%) for renewable energy supply, this objective is not
23 to be met without weighing the costs of alternative resources. The IRP's include
24 statements that lead to a conclusion that the wind investments are not least cost,
25 which brings in to question any conclusion of prudence.²

26

¹ See generally PU-09-547 MDU 2009 Integrated Resource Plan; See Also, PU-07-394 MDU 2007 Integrated Resource Plan.

² See 2009 IRP pg. 33 "Renewable resources that may not be price competitive but which have societal support or mandates", pg. 34 "legislative requirements are driving the need for increased wind generation which is a factor to be considered regardless of the economics of installing renewable generation sources"; See Also, 2007 IRP pg. 32 similar mandate driven analysis discussion, pgs. 33-34 wind not included in least-cost plan, and pg. 37 which does not include wind acquisition in 2 year plan, only review.

1 Q: **DID MDU SEEK ADVANCED APPROVAL FOR THE WIND PROJECTS?**

2 A: MDU sought and obtained certification from the Montana Commission that
3 Diamond Willow is an eligible renewable resource. On the other hand, MDU did
4 not utilize the Advanced Determination of Prudence law in North Dakota to seek
5 approval from the North Dakota Commission for any of the projects, including the
6 Cedar Hills wind project in North Dakota. Therefore, it can be concluded that
7 MDU proceeded to build these projects to meet Montana's current Renewable
8 Portfolio Standard (RPS) of 10% and future RPS of 15% by 2015.

9

10 Q: **IS THERE A COST DIFFERENTIAL IN BUILDING WIND PROJECTS IN**
11 **MONTANA VS. NORTH DAKOTA?**

12 A: Yes. From a ratepayer perspective, there is more incentive in North Dakota to
13 build wind projects than in Montana. It is cheaper to build wind farms in North
14 Dakota based on more favorable economic benefits like the North Dakota
15 investment tax credits, higher property tax reductions and laws that are not
16 parochial in nature like the ones in Montana. While it might have been prudent
17 from Montana ratepayers' perspective, for MDU to build Diamond Willow to meet
18 its Montana mandate, it was not the least cost plant necessary to serve North
19 Dakota customers.

20

21 Q: **CAN YOU OUTLINE THE DIFFERENCES?**

22 A: Yes, at a high level. The following table shows the capital cost differences as
23 presented in testimony.

2010 Projects		Sch N p 11	Per MW	Premium%
Dia. Willow 2	10.5	25,357,000	2,414,952	
Cedar	19.5	47,302,000		
15% ND Tax credit		(7,095,300)		
Net Cedar		40,206,700	2,061,882	
MW Premium			353,070	0.146
Total 10.5 MW Premium		3,707,238		

24

1 Staff recognizes that there are some timing differences to consider, but above
2 shows the final net capital cost of an investment in North Dakota as opposed to
3 plant built in Montana during the same time period.
4

5 One additional potential increased cost when comparing projects outside of North
6 Dakota is with respect to operating costs and the treatment of property taxes.
7 North Dakota has a 85% reduction on property taxes, which is not limited with
8 respect to how long the project is in service.

9 **Q: IS YOUR PROPOSAL ENCOURAGING THE ABANDONMENT OF THE**
10 **INTEGRATED SYSTEM APPROACH?**

11 **A:** Absolutely not. Staff believes in an integrated system approach when least cost
12 planning is employed and the results are beneficial to the ratepayers of North
13 Dakota. Staff is excluding the Montana wind projects because they were built for
14 Montanans, and it is more expensive than North Dakota wind projects. MDU has
15 not met its burden of proof as to its need or usefulness. We are excluding Cedar
16 Hills because MDU has not met its burden of proof as to its need or usefulness.
17 That said, a reallocation of generation assets is necessary on a going forward
18 basis. The direct assignment of Diamond Willow 1 & 2 by necessity requires a
19 greater allocation of the remaining generating units and purchased power costs.
20 Staff does not have the data to make such an adjustment and will rely on MDU
21 for providing this information. The resulting reallocation of resources will add
22 revenue requirements to Staff's recommendation—to what degree is unknown.
23

24 North Dakota does not have a mandate to build wind farms. According to MDU's
25 Integrated Resource Plans filed with the Commission, wind is characterized as
26 high in installation costs, but very low in energy costs. However, the
27 disadvantage is that it is an intermittent resource requiring some other generation
28 to produce energy during the times of less than desirable wind conditions. An
29 analysis showing the true cost of these wind projects to potential alternative
30 resources, to Staff's knowledge, does not exist. Staff's recommendation is not
31 an abandonment of the integrated system approach.

1 **Q: DID MDU SEEK AN ADVANCED DETERMINATION OF PRUDENCE (ADP)**
2 **FROM THIS COMMISSION BEFORE CONSTRUCTING THE CEDAR HILLS**
3 **WIND PROJECT?**

4 A: No. While North Dakota law (NDCC 49-05-16) provides for such a process, MDU
5 did not seek preapproval from the North Dakota Commission before it decided to
6 build any of the wind farms. A preapproval determination hearing would have
7 called for a detailed cost benefit analysis, justification and scrutiny of least-cost
8 alternatives for North Dakota customers and would have provided Staff with an
9 adequate forum, time and funding to evaluate such a proposal. It did not
10 happen. Further, during its audit, Staff was not able to receive any feasibility
11 studies or cost benefit analysis studies related to wind energy projects.

12

13 **Q: HOW HAS MDU BEEN HANDLING THE RETIREMENT OF REC'S IN ITS**
14 **MONTANA JURISDICTION?**

15 A: According to its filed Renewable Resource Standard annual reports, MDU has
16 met its RPS standard in Montana by retiring REC's from the Diamond Willow
17 wind farm. If Renewable Energy Credits (REC's) were assigned on a
18 proportional jurisdictional basis, MDU does not have sufficient REC's to meet its
19 Montana wind mandates. The shortage of REC's increases in 2015 when
20 Montana's RPS increases to 15%, if MDU allocates approximately 65% of the
21 wind projects to North Dakota. To date, MDU has been using North Dakota's
22 REC's (assuming project cost of Diamond Willow is allocated to North Dakota
23 ratepayers) to satisfy the Montana RPS. While the market is not robust, REC's
24 have some value in the marketplace through REC marketers and therefore an
25 integrated approach would require payment to North Dakota for such REC
26 retirements. If MDU were able to obtain recovery of the wind projects from North
27 Dakota ratepayers a credit against rates would be appropriate for the use of its
28 REC's.

29 On January 4, 2010, Northern States Power Company (NSP) filed an Application
30 for approval to sell excess Renewable Energy Credits (RECs) allocated to North
31 Dakota jurisdictional customers and credit the applicable proceeds back to

1 customers using the Fuel Cost Rider (FCR). See NDPSC Case No. PU-10-19.
2 According to NSP, the REC's were worth about \$1.50 each. On September 8,
3 2010, the Commission approved the request. MDU has not assigned any such
4 payments to North Dakota and has ignored the fairness doctrine between
5 jurisdictions in this instance if it were to recover costs of the projects from North
6 Dakota.

7
8 **Q: MR. MATHAI, PLEASE SUMMARIZE YOUR RECOMMENDATION**
9 **REGARDING THE TREATMENT OF WIND ENERGY INVESTMENTS AND**
10 **EXPENSES IN THIS FILING.**

11 A: The Staff recommends that the wind energy investments and expenses be
12 excluded from the revenue requirement requested by MDU in the current rate
13 case filing. Staff understands that the assignment of some or all of the wind
14 projects by MDU to another jurisdiction will cause some shifting of additional
15 generation and purchased power costs to North Dakota. Staff is not able to
16 quantify this effect and will rely on MDU to calculate the impact.

17
18 **Q: MR. MATHAI, DO YOU HAVE A RECOMMENDATION ON HOW TO TREAT**
19 **ANY WIND RELATED REVENUE REQUIREMENT IF THE COMMISSION**
20 **DECIDES TO INCLUDE ALL OR ANY PORTION OF THE WIND**
21 **INVESTMENTS AND EXPENSES IN THIS APPLICATION PROCESS?**

22 A: Yes. If for some reason, the Commission decides to include any portion of the
23 wind energy in the North Dakota jurisdictional portion, Staff recommends that the
24 Revenue Requirement be collected through a Renewable Rider. The rider
25 should be filed annually with updated cost projections and a true-up adjustment
26 for past costs and recoveries. Staff recommends the use of a rider so that
27 customers enjoy the early tax benefits associated with wind development.
28 Without a rider, customers' rates will reflect wind costs that are expected to
29 decline rapidly in the early years of a wind farm.

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GENERAL RATE BASE ISSUES

Aircraft Investment in General Plant-in Service

Q: MR. MATHAI, PLEASE EXPLAIN THE EXCEPTION THAT YOU TOOK WITH MDU BY ITS INCLUSION OF THE AIRCRAFT INVESTMENT IN THE RATE BASE?

A: MDU had included the aircraft investments in General Plant-in Service and related accumulated depreciation, depreciation expense, and O&M expenses. The Staff believes that aircraft equipment is not required to provide utility services or necessary to be funded by the ratepayers. It is for the convenience of MDU's top management and Board of Directors. Commercial air transportation is more efficient from a cost standpoint in providing services based on fair, just, and reasonable basis. If the utility management feels that a private aircraft is necessary, then stockholders should bear the cost. Therefore, net plant worth \$775,000 was removed from General Plant. See ~~Schedule GM-4-2~~ for the detailed calculation of the proposed adjustments regarding the Aircraft Plant in Service.

Deferred Generation Costs

Q: PLEASE EXPLAIN YOUR REASON FOR REMOVING FROM RATE BASE THE DEFERRED GENERATION COST BALANCE REQUESTED BY MDU.

A: The Deferred Generation Costs requested by MDU were incurred between 2006 and 2009 for the Lignite Vision 21 project and the Milton R. Young III project.

The unamortized balance included by MDU was \$1,547,000. See ~~Schedule GM-4-4~~ for workpaper details. Staff believes that including this in the rate base to earn a return, and collecting it over a ten year period through cost of service is in

1 effect implementing retroactive ratemaking. This is a violation of ratemaking
2 principles, since rates are set for a future period. Additionally, MDU had
3 sufficient earnings during this period to write these amounts off as expenses.
4 Furthermore, MDU did not seek prior authorization to book this as a regulatory
5 asset until December of 2009. MDU waited until that time to submit a letter to the
6 Commission Staff and later decided not to follow through as it filed this rate case.
7 When utilities incur substantial expenses which they plan to recover in future
8 rates, they obtain prior approval from the respective Commission. MDU did not
9 follow this practice. As I stated earlier, the current request represents retroactive
10 ratemaking by MDU. It is not a normal regulatory practice allowed by
11 Commissions.

12
13 **Q: SHOULD MDU HAVE WRITTEN OFF THESE EXPENSES WHEN THE**
14 **PROJECTS WERE ABANDONED TO BE CONSISTENT WITH THE FERC**
15 **ACCOUNTING?**

16 **A:** Yes. MDU made management decisions to investigate several different
17 generation possibilities. Proper accounting requires that MDU record these costs
18 to FERC's uniform system of accounts using account 183, Preliminary Survey
19 and Investigation Charges. The North Dakota Commission relies on the system
20 of accounts prescribed by FERC to maintain accounting order and consistency in
21 MDU's accounting and reporting of financial results. Account 183 requires that
22 this account be charged with all expenditures for preliminary surveys, plans,
23 investigations, etc., made for the purpose of determining the feasibility of utility
24 projects under contemplation. If construction of the project proceeds, these costs
25 are capitalized. If construction does not proceed and the projects are
26 abandoned, the costs are to be written off. Staff believes that MDU followed
27 proper accounting and wrote off these expenditures when it determined that the
28 project was abandoned.

29
30 Furthermore, if staff is correct, MDU recovered 39 cents on every dollar it wrote
31 off through tax savings.

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Q: ARE THE COMMISSION OR THE UTILITY RATEPAYERS RESPONSIBLE FOR ALL THE DECISIONS MADE BY THE UTILITY MANAGEMENT WHEN IT IS NOT IN THE BEST INTEREST OF ITS CUSTOMERS?

A: No. Neither the Commission nor the customers should be responsible for every decision made by the management. These were expenses that could have been written off in the year when MDU made the decision not to proceed further. Since MDU did not set up an authorized regulatory asset for this purpose, it should have already expensed these items for financial and accounting purposes. Unless MDU had authorization from the Commission, there is no basis for setting up a regulatory asset for purposes of cost recovery later in its next rate increase application.

Unamortized Loss on Debt Balance

Q: MR. MATHAI, WHAT IS YOUR PROPOSED TREATMENT OF THE UNAMORTIZED LOSS ON REQUIRED DEBT BALANCE INCLUDED BY MDU AS PART OF RATE BASE?

A: MDU had an unamortized loss on debt of \$5,015,081 at the beginning of the test period. After the yearly amortization amount of \$459,510, the unamortized balance of \$4,555,571 was included by MDU as Other Additions to the Rate base. Staff does not oppose the recovery of these costs as customers benefit from the resulting lower cost of debt. However, the loss on required debt should be part of the cost of debt, and it should be embedded in the new cost of debt issue rather than being considered as a separate cost of service item in the rate base and in the income statement. MDU chose to defer the loss on debt as a recovery item in this case for future recovery without getting prior approval from the Commission. Also, MDU included the loss balance in the rate base, while not giving consideration to the possible tax savings generated from this loss. MDU did not identify any deferred tax generated from this loss write off in the workpapers supplied to Staff.

1 Staff is of the opinion that it is appropriate to consider this unamortized loss on
2 bond redemption as a cost of debt financing and become part of the capital
3 structure. Since Staff is recommending the loss on debt balance as a part of the
4 debt portion of the Capital Structure, it is also removing the \$459,510 included as
5 an expense by MDU as part of its proposed ten year amortization.
6

7 Staff recognizes that it settled overall ROR and the above proposed adjustment
8 will necessarily have an adjustment that needs to be addressed.
9

10 Customer Deposits

11 **Q: DID MDU PROPOSE TO USE CUSTOMER DEPOSITS AS OTHER**
12 **DEDUCTIONS TO THE RATE BASE AS IS THE NORMAL REGULATORY**
13 **PRACTICE?**

14 **A:** No. MDU excluded this amount from the rate base. Its reasoning was that it pays
15 an interest on the customer deposits. Customer deposits are provided by
16 customers, not by investors. Also, customers are paid an interest while MDU
17 holds and uses this fund. Therefore, the proper way of treating in generally
18 accepted regulatory practices is by treating customer deposits as the non-
19 investor supplied capital, and allow MDU to recover the interest expense paid to
20 customers. Therefore, the Staff proposes to include the 13-month average
21 balance of \$946,219 in customer deposits as a reduction to the rate base and
22 allow MDU to recover the .85% annual interest paid to customers in 2010 as an
23 interest expense. See Schedules GM-4-7 and GM-4-7A.
24

25 FUEL AND PURCHASED POWER ISSUES

26
27 **Q: ARE YOU PROPOSING ANY ADJUSTMENT TO THE FUEL AND**
28 **PURCHASED POWER COST FROM WHAT MDU FILED?**

29 **A:** Yes. Staff has proposed the inclusion of the test year level revenues from Sales
30 for Resale of \$1,456,520. The Staff is proposing an additional fuel and
31 purchased power expense of \$1,063,438 to recover the cost of fuel related to the

1 Sale for Resale revenues reinstated by the Staff. See Schedules GM-4-6 and
2 GM-4-11.

3
4 **GENERAL INCOME STATEMENT ISSUES**

5
6 **Aircraft Related Expenses**

7 **Q: PLEASE EXPLAIN YOUR REASONS FOR REMOVING THE EXPENSES**
8 **RELATED TO THE AIRCRAFT EQUIPMENT.**

9 A: The Staff believes that owning Aircraft equipment is not required to provide utility
10 services or necessary to be funded by the rate payers as addressed earlier in the
11 rate base portion of my testimony. There is a level of commercial airline
12 expenses included in the Projected 2010 MDU cost of service. Therefore, the
13 allocated Aircraft expense related depreciation expense and the O&M expenses
14 totaling approximately \$55,000 were removed from the cost of service. See
15 Schedule GM-4-2.

16
17 **Deferred Generation Costs**

18 **Q: MR. MATHAI, PLEASE EXPLAIN YOUR REASONS FOR DISALLOWING THE**
19 **AMORTIZED PORTION OF THE DEFERRED GENERATION COSTS**
20 **INCLUDED BY MDU IN THE COST OF SERVICE?**

21 A: The Deferred Generation costs represent retroactive ratemaking as discussed
22 earlier in the rate base portion of my testimony. These were expenses that could
23 have been written off during the year a decision was made to proceed no further.
24 Amortization expenses associated with deferred generation that has been
25 abandoned were removed as a rate case expense.

26
27 **Labor Expenses – Payroll Annualization, Bonuses & Commissions,**
28 **Incentive Compensation**

29 **Q: WHAT PORTIONS OF THE LABOR EXPENSES PROPOSED BY MDU ARE**
30 **YOU TAKING EXCEPTIONS TO?**

1 A: First of all, the Staff is calculating the Annualization based on the latest payroll
2 information compared to MDU's calculation based on a 2009 selected category
3 of labor amounts grossed up for .32%. Second, Staff evaluated various
4 components of labor and took exception to the full inclusion of Bonuses and
5 Commissions and Incentive Compensation in the cost of service to be paid for by
6 the ratepayers.

7

8 It is the opinion of the Staff that the performance based incentives are beneficial
9 to both stockholders and ratepayers. Also, Staff believes the savings from the
10 performance enhancements should pay for the related incentive payments.
11 However, recognizing the benefits in better performance by employees to MDU
12 as a whole and its customers, we propose the Commission allow only 40% of
13 such costs in Cost of Service and exclude 60%. The reason I propose a 40% to
14 60% ratio between the customers and the stockholders, respectively, is to reflect
15 the fact that better realized financial performance is more beneficial to the
16 stockholders than ratepayers, while all other performance enhancements are
17 equally beneficial to both stockholders and customers. The Staff is proposing a
18 total reduction of \$1,419,000 from Labor Expense as proposed by MDU. See the
19 detail calculation of the items excluded from the proposed labor expense in
20 Schedules GM-4-12 and GM-4-13.

21

22 **Employee Benefits Expenses**

23 **Q: WHAT IS STAFF'S RECOMMENDATION REGARDING MDU'S MEDICAL AND**
24 **OTHER EMPLOYEE BENEFITS EXPENSE REQUEST?**

25 A: After a thorough review of all the elements of the Employee Benefits including
26 Pension and 401-K Plan, Staff supports MDU's Medical and other Benefits
27 Expense level as requested in its filing.

28

29 **General Corporate Allocation**

30 **Q: PLEASE EXPLAIN THE GENERAL CORPORATE ALLOCATION**
31 **ADJUSTMENT TO MDU'S PROPOSED EXPENSE LEVEL.**

1 A: Staff's review of the Corporate Allocation items assigned to North Dakota's
2 jurisdiction found that certain items totaling \$139,345 shown in Schedule GM 4-
3 14 should be shared 50/50 by the stockholders and customers. These are
4 common expenses spent on behalf of the Board of Directors that benefit
5 ratepayers and stockholders. It is fair, just and reasonable to be borne by both
6 ratepayers and stockholders, and thus shared on a 50/50 basis. Therefore, Staff
7 recommends removal of \$69,677 from MDU's requested cost of service.

8
9 **Transmission (WAPA) Expenses**

10 **Q: PLEASE EXPLAIN WHY YOU ARE PROPOSING AN ADJUSTMENT TO THE**
11 **WESTERN AREA POWER ADMINISTRATION (WAPA) ADDITIONAL**
12 **TRANSMISSION CHARGES.**

13 A: MDU accrued \$750,000 during 2009 for Western Area Power Administration
14 (WAPA) additional transmission charges, based on its transmission service
15 agreement effective January 1, 2009. The accrual was carried forward into the
16 2010 test year. After Staff's review, MDU proposed a more representative level
17 of expected expenses of \$250,000 for the Projected 2010 test year. See,
18 (NDPSC-DR14 and Onsite Request #19). The \$500,000 reduction in total
19 company expense results in a North Dakota adjustment of \$325,000. See the
20 detail calculation of the items excluded from the proposed Transmission (WAPA)
21 Expenses in Schedule GM-4-15.

22
23 **Coyote and Big Stone Generation Maintenance Expense**

24 **Q: PLEASE EXPLAIN STAFF'S NORMALIZATION ADJUSTMENT OF THE**
25 **COYOTE AND BIG STONE GENERATION MAINTENANCE.**

26 A: The average Coyote generation maintenance expense for 2007 through 2009
27 was \$1,547,350. The test year amount was \$2,000,799, which was high due to
28 special, periodically scheduled, generation maintenance. Therefore, in order to
29 normalize the test year expense the Staff proposes a reduction of \$453,449 from
30 MDU's projected test year expenses.

31

1 Similarly, the average Big Stone generation maintenance expense for 2007
2 through 2009 was \$937,957. The test year amount was \$780,094, which was
3 lower. Therefore, in order to normalize the test year expense the Staff proposes
4 an increase of \$157,863 from the MDU projected test year expenses. See the
5 calculation of these amounts in Coyote and Big Stone Generation Maintenance
6 Expenses, Schedules GM-4-16 and GM-4-17.

7
8 **Storm Damage Normalization**

9 **Q: MR. MATHAI, PLEASE EXPLAIN WHY YOU ARE PROPOSING STORM**
10 **DAMAGE NORMALIZATION.**

11 A: MDU incurred storm damages in 2009 and also in 2010, January and April.
12 According to the response to Staff's Data Request, MDU does not track and book
13 separately for storm costs as an extraordinary event expense. However, Staff
14 believes these are unusual and overly burdensome expenses caused by nature
15 which are beyond the control of MDU. FERC requires utilities to identify and
16 account for these expenses separately. Staff understands that in 2010, MDU
17 had two storm experiences in January and April. Staff segregated these
18 expenses based on MDU's response to its Data Request NDPSC-92, which
19 totaled \$498,432. We are recommending that MDU recover it over a three year
20 amortization period. MDU did not request special recovery treatment even
21 though the events occurred in 2010. Staff proposed an increase in O&M
22 expenses of \$129,279 to cover such expenses. Staff also recommends MDU
23 track such major Storm Costs per FERC Uniform System of Accounts and seek
24 Commission approval if it plans to recover such major costs as a Deferred
25 Regulatory Asset in future rates. See the detail calculation of the amount
26 included in the proposed MDU Cost of Service in Schedule GM-4-18.

27
28 **Customer Deposits Interest Expense**

29 **Q: DID MDU INCLUDE CUSTOMER DEPOSITS AS A DEDUCTION TO THE**
30 **RATE BASE?**

31 A: MDU did not include the Customer Deposits as a deduction to the Rate base in

1 its filing. The explanation was that it was not necessary to include as non-
2 investor supplied capital since MDU was paying an interest to the customers for
3 its use. It is normal regulatory practice that Customer Deposits are considered
4 as Non-investor Supplied Capital, and used to reduce the rate base. In return,
5 the utility is authorized to recover the Interest Expense from its customers. See
6 the detail calculation of the amount included in the proposed MDU Cost of
7 Service in Schedule GM-4-7A.

8
9 **ALTERNATIVE ENERGY RECOVERY RIDER (AER RIDER)**

10 **Q: MR. MATHAI, DO YOU HAVE A PROPOSAL IF THE COMMISSION ALLOW**
11 **MDU TO RECOVER ANY OF ITS WIND ENERGY COSTS?**

12 **A:** Yes. Staff recommends, because of the unique cost calculations and
13 government incentives associated with Wind Energy Investments and
14 Production, it is more transparent to all concerned to recover the net costs
15 through the Alternative Energy Recovery Rider (AER Rider) if those costs are
16 deemed prudent. It should be noted that the rider concept should be employed
17 in ratemaking process only in limited situations when it is facilitating transparency
18 of charges to the customers or when the charges have a limited time span to
19 collect under certain mandate.

20
21 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

22 **A:** Yes. However, the Staff maintains its rights to amend this testimony if new
23 information or clarifications to previously given information becomes available.

**EDUCATIONAL BACKGROUND AND EXPERIENCE
OF
GEORGE MATHAI, CPA**

Education: BS, Business Administration, Dallas Baptist University, Dallas, Texas (1974) Majors in Accounting, Journalism, Management, and Marketing

MPA, New York University (1980)

Professional Registration: Certified Public Accountant, State of Oklahoma #7999 (1985)

Professional Affiliations: Member of Oklahoma State Society of CPAs
Past Member of NARUC Subcommittees on:
Accounting and Finance; Electric; Gas; and
Transportation (1982-2007)
Past Member of AICPA

Experience:

Mr. Mathai has been engaged in utility matters and regulation full-time for 30 years. He has worked extensively in the revenue requirement calculation during the rate case processing of over 138 electric, gas, telephone, and water utilities. He specifically conducted Fuel Procurement Practice audits of 68 electric and gas utilities; 18 Water Companies for Revenue Requirements; 52 telephone utilities for Revenue Requirements; and as Administrator of Universal Service Fund Disbursements for 52 telephone utilities.

Mr. Mathai is the Managing Principal of Mathai & Associates Regulatory Consultants, LLC (MARC).

Prior to forming MARC, Mr. Mathai was an Executive Consultant with ERG Consulting Group/Legend Consulting Group Limited ("the Consulting Group"). The Consulting Group provides regulatory consulting, consulting engineering, and management consulting services to regulatory agencies and utility companies, including the Council of the City of New Orleans on rate and regulatory matters associated with Entergy New Orleans, Inc., Entergy Louisiana, LLC and Entergy Corporation and its operating subsidiaries. He has filed Revenue Requirement testimony in the recently concluded rate case of Entergy New Orleans Inc.'s Electric and Gas Operations. Mr. Mathai also testified before the Federal Energy Regulatory Commission ("FERC") regarding Generation System Agreement issues of Entergy Inc.'s Operating Companies on behalf of the Council of City of New Orleans.

Prior to joining the Consulting Group, Mr. Mathai was the Chief of the Accounting and Financial Auditing Department of the Public Utility Division of the Oklahoma Corporation Commission ("OCC"). Mr. Mathai directed the Department and was responsible for determining the revenue requirements and monitoring the fuel purchase practices of all regulated energy utilities in Oklahoma.

Concerning rate case processing, Mr. Mathai was extensively involved in the supervision of OCC's technical and legal staff, which provides financial and economic analysis and recommendations to the three-member statewide elected Commissioners on ratemaking, and

other utility regulatory matters. He held several auditing and management positions with OCC's Public Utility Division, including the Chief of Accounting and Financial Audits, Chief of Fund Administration for Oklahoma Universal Service Fund (OUSF) and E911 Fund, from August 1980 until October 2007. His professional experience includes electric, gas, water and telecommunications utilities with an emphasis on the development of revenue requirements, jurisdictional cost-of-service allocations, capital structure and rate-of-return studies and evaluations. Additionally, for several years, he was responsible for the fuel procurement practice audits, review and assessment of integrated resource planning (IRP) and fuel portfolio filings by major electric and gas utilities, and long-range fuel supply and capital expansion plans. Additionally, Mr. Mathai was the Chief of the OCC's Transportation (Motor Carriers) Division's Requirements, Auditing and Investigation and Tariffs' Department.

He also has provided successful testimony regarding current and pre-paid pension funding, incentive compensation, cost recovery of New Generation and Transmission Recovery Mechanism (NGTR), abandoned Black Fox Nuclear Project, settlement of Gas Take-or-Pay contracts, and the Tax Revision Act of 1986 (TRA).

He was successful in Commissions accepting his alternative ratemaking approaches, such as Performance Based Rate Changes (PBRC) and Formula Rate Plans (FRP).

Mr. Mathai has sponsored numerous expert testimonies on several major regulatory issues. He had proffered testimonies on all ratemaking areas, including overall revenue requirement, cost of service, system-cost allocations, corporate allocations, jurisdictional cost allocations, rate of return, fuel procurement and pricing. He had also provided testimonies at several times regarding Pension Expenses, Deferred Pension Expenses, Pre-paid pension Expenses, Other Post Employment Benefits (OPEBs), Incentive Compensation, and Uncollectible Expenses. Additionally, he had provided several testimonies on the following issues: (Only Major Issue List)

- Overall Rate Base and Revenue Requirement Calculation
- Plant in Service (Used and required to be used concept)
- Current and Accumulated Deferred Income taxes
- Accumulated Depreciation and Depreciation Expense
- Cash Working Capital Determination
- Coal and Gas Inventory Calculations
- Prepayments
- Pre-paid Pensions
- Non-Investor supplied Capital
- Construction Work In Progress (CWIP),
- New Generation and Transmission Recovery Mechanism (NGTR),
- Revenues and Proforma Revenues
- Payroll Expenses

- Pensions (Current and Deferred)
- Incentive Compensation
- Employee Benefits (Current and Post)
- Advertisement and Promotional Expenses
- Outside Services and Regulatory Expenses
- Vegetation Management/Tree Trimming Expense Recovery
- Factoring and Uncollectible Issues
- Overall Cost of Service Determination
- Rider Implementation and Safeguards
- Cost recovery of base rate and incremental Storm Damage costs,
- Hurricane Cost Recovery (Katrina, Rita, Ike and Gustav)
- Fuel Transportation and Capacity Rider Recoveries
- Recovery of Discontinued Black Fox Nuclear Project,
- Settlement of Gas Take-or-Pay contracts,
- The Tax Revision Act of 1986 (TRA),
- Alternative ratemaking approaches
 - Performance Based Rate Changes (PBRC),
 - Formula Rate Plans (FRP)
- Fund Administration (Funding and Disbursements)
 - OUSF
 - E911

Mr. Mathai's earlier experience involved the auditing of healthcare facilities in New York City for the State of New York, as well as several years of work as a journalist.

Mr. Mathai has served on the National Association of Regulatory Utility Commission's Staff Sub-Committees on Accounts, Electric, Gas, and Transportation from 1982 through 2007.

REPRESENTATIVE LISTING OF TESTIMONY EXPERIENCE OF GEORGE MATHAI, CPA			
Utility Company	Regulatory Agency	Docket No.	Date Filed
Entergy New Orleans	City of New Orleans	UD-08-03	11-17-08 12-16-09
Entergy Services, Inc.	Federal Energy Regulatory Commission	ER07-956-000	03-26-08
Arkansas Oklahoma Gas Company ("AOG")	Oklahoma Corporation Commission	2006000379	2007
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	200600339	2007
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	200600376	2007
Public Service Company of Oklahoma ("PSO"), a subsidiary of American Electric Power ("AEP")	Oklahoma Corporation Commission	200600285	2007
Center Point Energy, formerly known as ARKLA Gas Company	Oklahoma Corporation Commission	200600062	2006
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	200500361	2006
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	200500425	2006
Center Point Energy, formerly known as ARKLA Gas Company	Oklahoma Corporation Commission	200400187	2005
Oklahoma Gas and Electric ("OG&E")	Oklahoma Corporation Commission	200500151	2005

**REPRESENTATIVE LISTING OF TESTIMONY EXPERIENCE OF
GEORGE MATHAI, CPA**

Utility Company	Regulatory Agency	Docket No.	Date Filed
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	200400610	2005
Public Service Company of Oklahoma ("PSO"), a subsidiary of American Electric Power ("AEP")	Oklahoma Corporation Commission	200300076	2005
Public Service Company of Oklahoma ("PSO"), a subsidiary of American Electric Power ("AEP")	Oklahoma Corporation Commission	200300076	2004
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	980000683	1998
Public Service Company of Oklahoma ("PSO"), a subsidiary of American Electric Power ("AEP")	Oklahoma Corporation Commission	960000214	1997
Oklahoma Gas and Electric ("OG&E")	Oklahoma Corporation Commission	960000116	1996
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	940000477	1995
Center Point Energy, formerly known as ARKLA Gas Company	Oklahoma Corporation	940000354	1994
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	910001144	1993

**REPRESENTATIVE LISTING OF TESTIMONY EXPERIENCE OF
GEORGE MATHAI, CPA**

Utility Company	Regulatory Agency	Docket No.	Date Filed
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	920001394 920001653	1993
Center Point Energy, formerly known as ARKLA Gas Company	Oklahoma Corporation Commission	920001317	1992
Oklahoma Gas and Electric ("OG&E")	Oklahoma Corporation Commission	Consolidated Causes: 00898; 001055; 001005	1992
Public Service Company of Oklahoma ("PSO"), a subsidiary of American Electric Power ("AEP")	Oklahoma Corporation Commission	920001342	1992
Empire District Electric Company	Oklahoma Corporation Commission	900001001	1991
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	910001151 910001190	1991
Empire District Electric Company	Oklahoma Corporation Commission	000180	1987
Oklahoma Gas and Electric ("OG&E")	Oklahoma Corporation Commission	000259	1987
Oklahoma Natural Gas Company ("ONG"), A Division of ONEOK	Oklahoma Corporation Commission	000260	1987
Arkansas Oklahoma Gas Company ("AOG")	Oklahoma Corporation Commission	850000079	1985
Center Point Energy, formerly known as ARKLA Gas Company	Oklahoma Corporation Commission	29411	1985

**MONTANA-DAKOTA UTILITIES CO.
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

NDPSC Case No. PU-10-124
 Schedule GM-3-A

RATE BASE ADJUSTEMENTS

RB1	Wind Production Plant - Diamond Willow	(\$40,822,130)
RB1A	Wind Production Plant - Cedar Hills	(\$31,116,000)
RB1B	Accumulated Depreciation Production	\$ 2,266,000
RB2	Wind Transmission Plant - Diamond Willow	(\$1,731,862)
RB2A	Wind Transmission Plant - Cedar Hills	(\$99,000)
RB2B	Accumulated Depreciation Transmission	\$85,993
RB3	Aircraft Equipment	(\$1,080,835)
RB3A	Accumulated Depreciation Aircraft	\$305,817
RB4	Level of Deferred Generation costs	(\$1,547,000)
RB5	Unamortized Loss on debt	(\$4,555,571)
RB6	Level of Wind Farm ADIT	\$34,000
Wind Only	Additional Level of Wind Farm ADIT left out from filing	\$3,241,000
RB7	Customer Deposits	(\$946,219)

INCOME STATEMENT ADJUSTEMENTS

IS1	Depreciation Expense Transmission--Wind	(\$91,543)
IS2	Depreciation Expense Production--Wind	(\$3,596,907)
IS3	Depreciation Expense Aircraft	(\$38,478)
IS4	O&M Wind Farm Production/Transmission	(\$586,850)
IS5	Level of Deferred Generation costs	(\$172,000)
IS6	Corporate Aircraft O&M	(\$21,229)
IS7	Cost of Fuel Expense	\$1,063,438
IS8	Labor Expense Bonuses & Commissions	(\$520,447)
IS8A	Labor Expense Incentive Compensation	(\$627,054)
IS9	Labor Expense Annualization	(\$271,498)
IS10	Corporate Allocations to North Dakota Electric	(\$69,677)
IS11	Transmission	(\$325,000)
IS12	Coyote Generation Maintenance	(\$453,444)
IS13	Big Stone Generation Maintenance	\$157,863
IS14	Storm Costs of 2010	\$129,279
IS15	Customer Deposits Interest Expense	\$8,043
IS16	Wind Farm Ad Valorem Taxes	(\$134,000)
IS17	Interest Synchronization	\$5,952,000
IS18	Amortization of Loss on Debt	(\$459,510)

REVENUE ADJUSTEMENTS

REV1	Revenue from Sales for Resale	(\$1,456,520)
REV2	Margin Sharing Adjustment	(\$604,256)

**MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010
(000s)**

NDPSC Case No. PU-10-124
Schedule GM-3-1 (L-1)

	Test Year Revenue Requirements Per Company	Test Year Revenue Requirements Per Advocacy Staff
Rate Base	\$276,685	\$197,477
Recommended Rate of Return	8.699%	8.679%
Return Requirement	\$ 24,069	\$ 17,139
Current Operating Income	17,061	18,845
Return Excess or (Deficiency)	(\$7,008)	\$1,706
Current Income Tax Rate ¹	1.6436555	1.6436555
Revenue Excess or (Deficiency)	(\$11,518)	\$2,804
Difference between Company and Advocacy Staff		\$14,322

Note 1: Tax Factor at 39.16% Federal and State Combined Tax Rate 1.6436555

**MONTANA-DAKOTA UTILITIES CO.
 PROJECTED OPERATING INCOME AND ROR
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010
 (000s)**

NDPSC Case No. PU-10-124
 Schedule GM-3-2

	Before Additional Revenue Requirements ^{1/}	Advocacy Staff Projected 2010 Revenue Requirements ^{1/}
Operating Revenues		
Sales	\$110,925	\$110,925
Sales for Resale	0	2,060
Other	5,075	5,075
Total Revenues	<u>\$ 116,000</u>	<u>\$ 118,060</u>
Operating Expenses		
Operation and Maintenance		
Fuel & Purchased Power	\$ 33,267	\$ 34,330
Other O&M	40,485	37,906
Total O&M	<u>\$ 73,752</u>	<u>\$ 72,236</u>
Depreciation	18,757	14,398
Taxes Other Than Income	4,636	4,502
Current Income Taxes ^{2/}	1,794	8,079
Deferred Income Taxes	0	0
Total Expenses	<u>\$ 98,939</u>	<u>\$ 99,215</u>
Operating Income	<u>\$17,061</u>	<u>\$18,845</u>
Rate Base	<u>\$276,685</u>	<u>\$197,477</u>
Rate of Return	6.166%	9.543%

1/ Statement M, Amended Page 1.

2/ Reflects state and federal taxes at 39.16%.

**MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010**

NDPSC Case No. PU-10-124
Schedule GM-3-3 (M-1)

	Company Per Books	Company Projected Adjustments	Company Projected 2010	Advocacy Staff Adjustments to Projected 2010	Advocacy Staff Projected 2010
Operating Revenues					
Sales	\$ 105,442	\$ 5,483	\$ 110,925	\$ -	\$ 110,925
Sales for Resale	4,698	(4,698)	-	2,060	2,060
Other	4,684	391	5,075	0	5,075
Total Revenues	\$ 114,824	\$ 1,176	\$ 116,000	\$ 2,060	\$ 118,060
Operating Expenses					
Fuel and Purchased Power	\$ 32,069	\$ 1,198	\$ 33,267	\$ 1,063	\$ 34,330
O&M Expenses:					
Production			\$ 15,650	\$ (882)	\$ 14,768
Transmission			5,305	(325)	4,980
Distribution			5,966	129	6,095
Customer Accounting			2,123	8	2,131
Customer Service & Information			292	-	292
Sales			113	-	113
Administrative & General			11,036	(1,509)	9,527
Subtotal O&M	\$ 39,364	\$ 1,121	\$ 40,485	\$ (2,579)	\$ 37,906
Total Operating Expenses	\$ 71,433	\$ 2,319	\$ 73,752	\$ (1,516)	\$ 72,236
Depreciation and Amortization	15,705	3,052	18,757	(4,359)	14,398
Taxes Other Than Income	4,338	298	4,636	(134)	4,502
Current Income Taxes	(3,811)	5,605	1,794	6,285	8,079
Deferred Income Taxes	8,806	(8,806)	-	-	-
Total Expenses	\$ 96,471	\$ 2,468	\$ 98,939	\$ 276	\$ 99,215
Operating Income	\$ 18,353	\$ (1,292)	\$ 17,061	\$ 1,784	\$ 18,845
Rate Base	\$ 210,903	\$ 67,259	\$ 276,685	\$ (79,208)	\$ 197,477
Rate of Return	8.702%		6.166%		9.543%

**MONTANA-DAKOTA UTILITIES CO.
UTILITY CAPITAL STRUCTURE
TWELVE MONTHS ENDING DECEMBER 31, 2009
PROJECTED 2010**

NDPSC Case No. PU-10-124
Schedule GM-3-5

	<u>Balance</u>	<u>Ratio</u>	<u>Cost</u>	<u>Required Return</u>	<u>Return with Tax</u>
<u>2009</u>					
Long Term Debt	\$280,502,591	45.662%	6.845%	3.126%	3.126%
Short Term Debt 1/	1,880,548	0.306%	11.590%	0.035%	0.035%
Preferred Stock	15,600,000	2.540%	4.594%	0.117%	0.192%
Common Equity	316,314,714	51.492%	11.500%	5.922%	9.734%
Total	\$614,297,853	100.000%		9.200%	13.087%
<u>Advocacy Staff Projected 2010</u>					
Long Term Debt	\$280,502,591	41.756%	6.845%	2.858%	2.858%
Unamort. Loss on Bond Redemption	\$7,561,148	1.126%	6.845%	0.077%	0.077%
Short Term Debt 1/	20,829,409	3.101%	2.535%	0.079%	0.079%
Preferred Stock	15,500,000	2.306%	4.590%	0.106%	0.174%
Common Equity	347,368,141	51.710%	10.500%	5.559%	9.137%
Total	\$671,761,289	100.00%		8.679%	12.325%

1/ Reflects average monthly balance.

**MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY -NORTH DAKOTA
INTEREST EXPENSE
ADVOCACY STAFF PROJECTED 2010**

NDPSC Case No. PU-10-124
Schedule GM-3-6
Page 1 of 3

	<u>Projected 2010</u>	<u>Advocacy Staff 2010</u>
Rate Base 1/	\$276,685	\$197,477
Weighted Cost of Debt	<u>2.970%</u>	<u>3.01%</u>
Interest Expense	<u>\$8,218</u>	<u>\$5,952</u>

1/ Statement N, Amended Page 1.

**MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
CALCULATION OF INCOME TAXES
PROJECTED 2010
(000s)**

NDPSC Case No. PU-10-124
Schedule GM-3-6
Page 2 of 3

	Projected 2010	Advocacy Staff W/Out Production and ITC 2010
Operating Revenues		
Sales Revenues	\$110,925	\$110,925
Sales for Resale		\$2,060
Other Revenues	5,075	\$5,075
Total Operating Revenues	<u>\$ 116,000</u>	<u>\$ 118,060</u>
Operating Expenses		
Operation and Maintenance		
Cost of Fuel & Purchased Power	33,267	34,330
Other O&M	40,485	37,906
Total O&M	<u>73,752</u>	<u>72,236</u>
Depreciation and Amortization Expense	18,757	14,398
Taxes other Than Income	4,636	4,502
Total Operating Expenses	<u>97,145</u>	<u>91,136</u>
Gross Adjustments to Operating Income	<u>18,855</u>	<u>26,924</u>
Deductions and Adjustments to Book Income:		
Interest 1/	8,218	5,952
Total Adjustments to Taxable Income	<u>8,218</u>	<u>5,952</u>
Taxable Income	10,637	20,972
Federal & State Income Taxes	4,165	8,213
Production Tax Credit 2/	(2,237)	-
Full Normalization	(134)	(134)
Total Income Taxes	<u>\$1,794</u>	<u>\$8,079</u>

1/ Amended Page 43.

2/ Page 44.

**MONTANA-DAKOTA UTILITIES CO.
 PRODUCTION TAX CREDIT
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

NDPSC Case No. PU-10-124
 Schedule GM-3-6
 Page 3 of 3

	<u>Projected 2010</u>	<u>Advocacy Staff 2010</u>
<u>Generation - Kwh</u>		
Cedar Hills	64,700,000	66,619,800
Diamond Willow	99,500,000	102,492,000
Total	<u>164,200,000</u>	<u>169,111,800</u>
Production Tax Credit	(\$0.021)	(\$0.021)
Total Production Tax Credit	(\$3,448,200)	(\$3,551,348)
Allocated to North Dakota 1/	<u>(\$2,237,491)</u>	<u>(\$2,304,422)</u>

1/ Allocated on Kwh sales factor.

Allocation Percentage KWH Sales - Factor 16 64.888666%

MONTANA-DAKOTA UTILITIES CO.

RATE BASE

ELECTRIC UTILITY - NORTH DAKOTA

TWELVE MONTHS ENDED DECEMBER 31, 2009

PROJECTED 2010

(000s)

NDPSC Case No. PU-10-124
Schedule GM-3-7 (N-1)

	Per Books	Projected Adjustments	Company Projected 2010	Staff Adjustments to Projected 2010	Staff Projected 2010
Electric Plant in Service	\$534,847	\$80,376	\$615,223	1/ (\$74,851)	\$540,372
Accumulated Reserve for Depreciation	288,104	14,389	302,493	(2,658)	299,835
Net Electric Plant in Service	\$246,743	\$65,987	\$312,730	(\$72,193)	\$240,537
CWIP in Service Pending Reclassification	1,477	(1,477)	0	0	0
Total Electric Plant in Service	\$ 248,220	\$ 64,510	\$ 312,730	\$ (72,193)	\$ 240,537
Additions					
Materials and Supplies	\$ 4,782	\$ 295	\$ 5,077	\$ -	\$ 5,077
Fuel Stocks	2,944	11	2,955	0	2,955
Prepayments	102	271	373	0	373
Unamortized Loss on Debt	5,015	(459)	4,556	(4,556)	0
Deferred Generation Costs	0	1,547	1,547	(1,547)	0
Decommission of Retired Plant	0	(353)	(353)	0	(353)
Total Additions	\$ 12,843	\$ 1,312	\$ 14,155	\$ (6,103)	\$ 8,052
Total Before Deductions	\$ 261,063	\$ 65,822	\$ 326,885	\$ (78,296)	\$ 248,589
Deductions					
Accumulated Deferred Income Tax	\$49,902	\$71	\$49,973	(\$34)	\$49,939
Accumulated Investment Tax Credit	94	(\$94)	0	\$0	\$0
Customer Deposits	0	\$0	0	\$946	\$946
Customer Advances	164	\$63	227	\$0	\$227
Total Deductions	\$ 50,160	\$ 40	\$ 50,200	\$ 912	\$ 51,112
Total Rate Base	\$210,903	\$65,782	\$276,685	(\$79,208)	\$197,477

/1 Includes CWIP in Service by function.

MONTANA-DAKOTA UTILITIES CO.
 RATE BASE ADJUSTMENTS
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010
 ('000'S)

NDPSC Case No. PU-10-124
 Schedule GM-3-8
 Page 1 of 3

Function	Company Projected 2010	RB1 Wind Production Diamond Willow	RB1A Wind Production Cedar Hills	RB1B Accum. Deprec Production	RB2 Wind Transmision Diamond Willow	RB2A Wind Transmision Cedar Hills
Electric Plant in Service	\$615,223	(\$40,822)	(\$31,116)		(\$1,732)	(\$100)
Accumulated Reserve for Depreciation	302,493			(2,266)		
Net Electric Plant in Service	\$ 312,730	\$ (40,822)	\$ (31,116)	\$ 2,266	\$ (1,732)	\$ (100)
CWIP in Service Pending Reclassification						
Total Electric Plant in Service	\$ 312,730	\$ (40,822)	\$ (31,116)	\$ 2,266	\$ (1,732)	\$ (100)
Additions						
Materials and Supplies	\$ 5,077					
Fuel Stocks	2,955					
Prepayments	373					
Unamortized Loss on Debt	4,556					
Deferred Generation Costs	1,547					
Decommission of Retired Plant	(353)					
Total Additions	\$ 14,155	\$ -	\$ -	\$ -	\$ -	\$ -
Total Before Deductions	\$ 326,885	\$ (40,822)	\$ (31,116)	\$ 2,266	\$ (1,732)	\$ (100)
Deductions						
Accumulated Deferred Income Taxes	\$ 49,973					
Accumulated Investment Tax Credits	-					
Customer Deposits	-					
Customer Advances	227					
Total Deductions	\$ 50,200	\$ -	\$ -	\$ -	\$ -	\$ -
Total Rate Base	\$ 276,685	\$ (40,822)	\$ (31,116)	\$ 2,266	\$ (1,732)	\$ (100)

Function	RB2B	RB3	RB3A	RB4	RB5	RB6	RB7
	Accum. Deprec Transmission	Aircraft Equipment Account 392.3	Accum. Deprec Account 392.3	Level of Def. Gen. Costs Excluding Big Stone II	Unamortized Loss on Debt	Level of Wind Farm ADIT	Customer Deposits
Electric Plant in Service							
Accumulated Reserve for Depreciation		(\$1,081)					
Net Electric Plant in Service	\$ 86	\$ (1,081)	\$ (306)	\$ -	\$ -	\$ -	\$ -
CWIP in Service Pending Reclassification							
Total Electric Plant in Service	\$ 86	\$ (1,081)	\$ 306	\$ -	\$ -	\$ -	\$ -
Additions							
Materials and Supplies							
Fuel Stocks							
Prepayments					(4,556)		
Unamortized Loss on Debt				(1,547)			
Deferred Generation Costs							
Decommission of Retired Plant							
Total Additions	\$ -	\$ -	\$ -	\$ (1,547)	\$ (4,556)	\$ -	\$ -
Total Before Deductions	\$ 86	\$ (1,081)	\$ 306	\$ (1,547)	\$ (4,556)	\$ -	\$ -
Deductions							
Accumulated Deferred Income Taxes						\$ (34)	
Accumulated Investment Tax Credits							946
Customer Deposits							
Customer Advances							
Total Deductions	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (34)	\$ 946
Total Rate Base	\$ 86	\$ (1,081)	\$ 306	\$ (1,547)	\$ (4,556)	\$ 34	\$ (946)

Function	Level of Wind Farm ADIT	M&S	Fuel Stocks	Prepayments	Adjustment Totals	Advocacy Staff Projected 2010
Electric Plant in Service					\$74,851	\$540,372
Accumulated Reserve for Depreciation					2,658	299,835
Net Electric Plant in Service	\$ -	\$ -	\$ -	\$ -	\$ 72,193	\$ 240,537
CWIP in Service Pending Reclassification					\$0	
Total Electric Plant in Service	\$ -	\$ -	\$ -	\$ -	\$ 72,193	\$ 240,537
Additions						
Materials and Supplies					\$ -	\$ 5,077
Fuel Stocks					-	2,955
Prepayments					-	373
Unamortized Loss on Debt					4,556	-
Deferred Generation Costs					1,547	-
Decommission of Retired Plant					-	(353)
Total Additions	\$ -	\$ -	\$ -	\$ -	\$ 6,103	\$ 8,052
Total Before Deductions	\$ -	\$ -	\$ -	\$ -	\$ 78,296	\$ 248,589
Deductions						
Accumulated Deferred Income Taxes					\$ 34	\$ 49,939
Accumulated Investment Tax Credits					-	-
Customer Deposits					(946)	946
Customer Advances					-	227
Total Deductions	\$ -	\$ -	\$ -	\$ -	\$ (912)	\$ 51,112
Total Rate Base	\$ 3,241	\$ -	\$ -	\$ -	\$ 79,208	\$ 197,477

**MONTANA-DAKOTA UTILITIES CO.
 RATE BASE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

ADJUSTMENTS TO PLANT

	<u>Amount</u>	<u>REF</u>
Total wind production (DW & CH) Plant in Service - North Dakota	\$ (71,938,130)	Stmt N p.11 of 23 RB1/RB1A
Total wind transmission (DW & CH) Plant in Service - North Dakota	\$ (1,830,862)	Stmt N p.11 of 23 RB2/RB2A
Proposed Adjustment to remove wind related plant in service by Advocacy Staff	\$ (73,768,992)	Note 1
Level of aircraft equipment included in jurisdictional plant in service Account 392.3	\$ 1,080,835	
Proposed Adjustment Amount by Advocacy Staff	\$ (1,080,835)	Stmt. C p. 5 of 6 RB3 Note 2

Note 1

The Advocacy Staff believes that wind related energy is an optional source of energy for North Dakota customers. We suggest that the wind energy related investments and expenses included in this rate case filing be bifurcated and treated separately. See detailed explanation in Advocacy Staff Testimony Exhibit - October 16, 2010

Note 2

Aircraft equipment is not required to provide utility services. It is for the convenience of the top management and the Board of Directors. Commercial air transportation is more efficient from a cost standpoint in providing services based on fair, just, and reasonable basis. If the utility management feels that the private aircraft is necessary, then stockholders should bear the cost.

MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010

ADJUSTMENTS TO DEPRECIATION

Removal of aircraft from cost of service depreciation expense

Annual depreciation expense for aircraft
 See Note 2 in RB Adjustment No. RB1/RB1A/RB2/RB2A/RB3
Depreciation Expense for projected 2010 (Other Production/Wind)

REF	Response NO.
NDPSC 12, DR 077, Attachment A, Page 1 of 3	DR 077, Attachment A, p. 6 of 7

3.56% \$ 1,080,835 \$ 38,478

Annual depreciation expense for aircraft

See Note 2 in RB Adjustment No. RB1/RB1A/RB2/RB2A/RB3

Depreciation Expense for projected 2010 (Other Production/Wind)

REF	DR No. 052, Attachment A, p. 1 of 1	DR No. 075, Attachment A, p. 1 of 1	Conf. DR. 09/7/10 No. 3
Diamond Willow (19.5 + 10.5 MW)	\$ 40,822,130	\$ 2,041,107	\$ -
Cedar Hills (19.5 MW)	\$ 31,116,000	\$ 1,555,800	\$ 1,000,691
	\$ 3,596,907		

Diamond Willow (19.5 + 10.5 MW)
 Cedar Hills (19.5 MW)

Diamond Willow Cedar Hills

See Note 1 in RB Adjustment No. RB1/RB1A/RB2/RB2A/RB3
Depreciation Expense for projected 2010 (Transmission/Wind)

REF	DR No. 052, Attachment A, p. 1 of 1	DR No. 075, Attachment A, p. 1 of 1	Conf. DR. 09/7/10 No. 3
Diamond Willow (19.5 + 10.5 MW)	\$ 1,731,862	\$ 86,593	\$ -
Cedar Hills (19.5 MW)	\$ 99,000	\$ 4,950	\$ 3,184
	\$ 91,543		

Diamond Willow (19.5 + 10.5 MW)
 Cedar Hills (19.5 MW)

Diamond Willow Cedar Hills

See Note 1 in RB Adjustment No. RB1/RB1A/RB2/RB2A/RB3
 Total Wind O&M

\$ 2,684,575	\$ 1,003,874
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\$ 2,684,575 \$ 1,003,874

MONTANA-DAKOTA UTILITIES CO.
RATE BASE
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010

LEVEL OF WIND FARM INVESTMENTS - PLANT IN SERVICE

Total Wind Farm Investments included in jurisdictional plant in service

Other Production-Wind	Account No.	REF	Total Company	North Dakota
Diamond Willow 10.5 MW wind	344	Stmnt N p.11 of 23	\$ 25,357,000	\$ 16,680,000
Diamond Willow 19.5 MW wind	344	Conf. DR 9/7/10 No.	\$ 36,700,959	\$ 24,142,130
Total Diamond Willow			\$ 62,057,959	\$ 40,822,130
Cedar Hills 19.5 MW wind	344	Stmnt N p.11 of 23	\$ 47,302,000	\$ 31,116,000
Total production-wind			\$ 109,359,959	\$ 71,938,130
Transmission-Wind				
Diamond Willow Line Interconnect 10.5 MW	355	Stmnt N p.11 of 23	\$ 18,000	\$ 12,000
Diamond Willow 19.5 MW wind	355	Conf. DR 9/7/10 No.	\$ 2,579,793	\$ 1,719,862
Total Diamond Willow			\$ 2,597,793	\$ 1,731,862
Cedar Hills Line Interconnect	355	Stmnt N p.11 of 23	\$ 143,000	\$ 99,000
Total transmission-wind			\$ 5,338,586	\$ 1,830,862
Total-Wind Investment			\$ 114,698,545	\$ 73,768,992

	REF	Total Company
Total wind production (DW & CH) Plant in Service - North Dakota	Stmnt N p.11 of 23	\$ 71,938,130
Total wind transmission (DW &CH) Plant in Service - North Dakota	Stmnt N p.11 of 23	\$ 1,830,862
Total Investment		\$ 73,768,992
Accumulated Reserve for Depreciation (DW)	Stmnt N p.12 of 23	\$ 2,266,000

Advocacy Staff Proposed Amount of Wind Production and Transmission in the Rate Base \$0.00
 Proposed Adjustment to remove Plant in Service-Wind by advocacy staff \$ (73,768,992)

Note 1

	REF	As MDU filed ND Wind Rev
Total wind production (DW & CH) Plant in Service - North Dakota	Stmnt N p.11 of 23 & Conf. DR 9/7/10 No. 3	Ret Req \$ 6,220,045 Rev. Req \$ 10,223,612 TL O&M \$ 323,939 TL Rev. Ret \$ 10,547,551
Total wind transmission (DW & CH) Plant in Service - North Dakota Total Investment	Stmnt N p.11 of 23 & Conf. DR 9/7/10 No. 3	
Rate Base Adjustment No. 1B (Production)		
Accumulated depreciation as of 12/31/2009 for 19.5 MW (DW)	Stmnt N p.12 of 23	
Additional Accumulated depreciation for 30 MW for projected 2010 (DW)		
Additional Accumulated depreciation for projected 2010 for 19.5 MW (CH)		

Note 2

	REF	As MDU filed ND Wind Rev
Rate Base Adjustment No. 2B (Transmission)		
Accumulated depreciation as of 12/31/2009 for 19.5 MW (DW)	Stmnt N p.12 of 23	
Additional Accumulated depreciation for 30 MW for projected 2010 (DW)		
Additional Accumulated depreciation for projected 2010 for 19.5 MW (CH)		

Depreciation Expense for projected 2010 (Production)

	REF	DR No.	DR No. 052, Attachment A, p. 1 of 1	DR No. 075, Attachment A, p. 1 of 1	DR No. 075, Attachment B, p. 1 of 1	DR No. 075, Attachment C, p. 1 of 1
Diamond Willow (19.5 MW)	5.00%	\$ 24,142,130	\$ 1,207,107			
Diamond Willow (10.5 MW)	5.00%	\$ 16,680,000	\$ 834,000			
Cedar Hills (19.5 MW)	5.00%	\$ 31,116,000	\$ 1,555,800			
						\$ 3,596,907

**MONTANA-DAKOTA UTILITIES CO.
 RATE BASE/INCOME STATEMENT
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

ADJUSTMENT TO AIRCRAFT EQUIPMENT (392.3)

Level of aircraft equipment included in jurisdictional plant in service Account 392.3 Common plant - Electric plant in service	\$ 1,080,835		
Advocacy Staff Proposed Amount	\$ -		
		REF	
		NDPSC-DR 010, Attachment	
		A, Page 3	RB3
Proposed Adjustment Amount by Advocacy Staff to Plant In Service	\$ (1,080,835)	Note 1	
		Response NO. NDPSC 12,	
		Attachment A, Page 1 of 3	
Removal of aircraft from cost of service depreciation expense			
Annual depreciation expense for aircraft	3.56% \$ 1,080,835	\$38,478	Statement 1, p. 2 of 3 Note 1
			IS3
Level of accumulated depreciation included in jurisdictional plant in service Account 392.3 Common plant - Electric plant in service	\$ 305,817	Note 1	
Advocacy Staff Proposed Amount	\$ -		
		NDPSC-DR 010, Attachment	
		B, Page 3 of 4	RB3A
Proposed Adjustment Amount by Advocacy Staff to Rate Base	\$ 305,817	Note 1	
Corporate Aircraft O&M (subsection A&G) account 921	\$ 16,693	WP Statement H, p. 3	IS3

Note 1

This expense is not reasonable for the ratepayers. It is simply for the convenience of MDU's Senior level executives. It is not necessary for the purpose of providing fair, just, and reasonable service. A reasonable level of commercial air travel is already reflected in the cost of service.

**MONTANA-DAKOTA UTILITIES CO.
 ACCUMULATED DEPRECIATION
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

ADJUSTMENTS TO ACCUMULATED DEPRECIATION

Rate Base Adjustment No. 1B (Other Production/Wind)

Accumulated depreciation as of 12/31/2009 for 19.5 MW (DW)	\$ 2,266,000	RB 1B	\$ 2,266,000
Additional Accumulated depreciation for 30 MW for projected 2010 (DW)	\$ 2,041,107		\$ 2,041,107
Additional Accumulated depreciation for projected 2010 for 19.5 MW (CF)	\$ 1,555,800		\$ 555,109
	<u>\$ 5,862,907</u>		<u>\$ 4,862,216</u>

Rate Base Adjustment No. 2B (Transmission/Wind)

Accumulated depreciation as of 12/31/2009 for 19.5 MW (DW)	\$ 85,993	RB 2B	\$ 85,993
Additional Accumulated depreciation for 30 MW for projected 2010 (DW)	\$ 86,593		\$ 86,593
Additional Accumulated depreciation for projected 2010 for 19.5 MW (CH)	\$ 4,950		\$ 1,766
	<u>\$ 177,536</u>		<u>\$ 174,352</u>

Total Wind Accum Depr

\$ 6,040,443	Diamond Willow	\$ 5,036,568
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Rate Base Adjustment No. 3A (Aircraft)

Level of Accumulated Depreciation included in Jurisdictional Plant In Service (Account 392.3)	\$ 305,817	RB 3A	\$ 1,003,874
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MONTANA-DAKOTA UTILITIES CO.

**RATE BASE
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010**

LEVEL OF DEFERRED GENERATION COSTS EXCLUDING THE BIG STONE II COSTS

Deferred generation costs included by company in rate base \$ 1,547,000

Advocacy Staff Proposed Amount \$0.00

Proposed Adjustment Amount \$ (1,547,000)^{of 23}

REF
Statement N, Page 19



Note 1

These costs were incurred between 2006 and 2009. The company had sufficient earnings during this period to write these amounts off as expenses. Additionally, the company did not come and seek prior authorization to book this as a regulatory asset until June 2009. The company waited until June 2009 to submit a letter to the Commission staff and later decided not to follow through as they filed this rate case. When the utilities incur substantial expenses which they plan to recover in future rates, they obtain prior approval from the respective Commission. The company did not follow this practice. The current request represents a retroactive ratemaking by the company. It is not a normal regulatory practice allowed by the Commissions across the country.

Company made management decisions to enter into several generation related contracts and to withdraw from those contracts based on their assessments and decisions. The Commission nor the customers should be responsible for every decision made by the management. These were expenses that could have been written off the year when they made the decision not to proceed further. Since the company did not set up an authorized regulatory asset for this purpose, the company should have and would have expensed these items for financial and accounting purposes, when incurred. Unless, the company had the authorization from the Commission there was no FERC precedence or rules to set it up as a regulatory asset.


**MONTANA-DAKOTA UTILITIES CO.
 RATE BASE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

UNAMORTIZED LOSS ON DEBT ALLOCATED TO NORTH DAKOTA

Unamortized loss on debt included in North Dakota Rate Base	\$ 5,015,081
Removed from Rate Base for inclusion as part of capital structure	
Less Amount Included in Income Statement for Annual Amortization	\$ (459,510)
Net amount in Rate Base	\$ 4,555,571
Advocacy Staff Proposed Amount	\$ -

REF

NDPSC-074-Response
 Attachment A, page1
 Statement N, page 18
 of 23
 Note 1



Proposed Adjustment Amount by Advocacy Staff to Rate Base (Jurisdictional Amount) \$ (4,555,571)

Note 1

The unamortized loss on debt of \$4,555,571 should appropriately be part of cost of debt, rather than being considered as a separate cost of service item in the rate base and in the income statement. Including it in the rate base to earn a return and in the income statement as an expense would make the customers pay a full return for a debt cost. Therefore, it is appropriate to consider this unamortized loss on bond redemption as a cost of debt financing. Therefore, the advocacy staff is also removing \$459,510 as included by the company as part of a ten year amortization in the income statement. Instead now the company is allowed to recover this as a part of the total cost of capital.

**MONTANA-DAKOTA UTILITIES CO.
 SALE FOR RESALE AND MARGIN SHARING REVENUE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

ADJUSTMENT TO REVENUES

		<u>REF</u>
		Statement M, Statement M, Page 6 Page 10 of 44 of 44 (Fuel Revenue) (Fuel Costs)
1. Sale for Resales	\$ 1,456,520	
2. Margin Sharing Adjustment	\$ 604,256	
Company Proposed Sale for Resale and Margin Sharing	\$ -	
Advocacy Staff Proposed Amount	\$ 1,456,520	Note 1
	\$ 604,256	Note 1
Proposed Adjustment by Advocacy Staff		
Sale for Resale	\$ 1,456,520	REV.1
Margin Sharing Adjustment	\$ 604,256	REV.2

Note 1

Company proposed to remove all sales for resale revenues and margin sharing adjustment from the projected 2010 Electric revenues. Advocacy staff proposes that a minimum level of \$1,456,520, as reflected in 2009 per books numbers, should be reflected in projected 2010 sale for resale, and \$604,256 for margin sharing adjustment should be reflected for projected 2010 margin sharing adjustment. Any amount above the 2009 level per book numbers should be flowed through the fuel adjustment clause to the benefit of the ratepayers, with 90% going back to the customers and 10% retained by the stockholders.

The fuel cost of \$1,063,438 related to the above Sales for Resales revenue is embedded in the overall fuel cost for the year 2009. See Adjustment #IS7.

NDPSC Case No. PU-10-124

Schedule-GM-4-7

RB Adjustment No. 7-GM7

IS Adjustment No. 15-GM15

**MONTANA-DAKOTA UTILITIES CO.
RATE BASE/INCOME STATEMENT
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010**

CUSTOMER DEPOSITS

North Dakota

Jul-09	940,897
Aug-09	944,638
Sep-09	944,108
Oct-09	961,897
Nov-09	970,103
Dec-09	964,796
Jan-10	962,109
Feb-10	962,333
Mar-10	952,881
Apr-10	944,273
May-10	938,937
Jun-10	915,440
Jul-10	898,435

Customer Deposit 13 month average \$946,219

Annual Interest Expense \$946,219 * 0.85% \$8,043

Proposed Adjustment Amount	(946,219)	RB
Proposed Adjustment Amount	\$8,043	IS 15

**MONTANA-DAKOTA UTILITIES CO.
 RATE BASE/INCOME STATEMENT
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

CUSTOMER DEPOSITS

North Dakota	
Jul-09	940,897
Aug-09	944,638
Sep-09	944,108
Oct-09	961,897
Nov-09	970,103
Dec-09	964,796
Jan-10	962,109
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Jun-10	915,440
Jul-10	898,435

Customer Deposit 13 month average \$946,219

Annual Interest Expense \$946,219 * 0.85% \$8,043

Proposed Adjustment Amount (946,219)
 Proposed Adjustment Amount \$8,043



Note 1

Note 1

Customer deposits are provided by customers, not by investors. Also, customers are paid an interest while the company holds and uses this fund. Therefore, the proper way of treating in generally accepted regulatory practices is by treating customer deposits as a non investor supplied capital and allowing the interest expense to be recovered by the company. Therefore, the Advocacy Staff proposes to include the 13-month average balance of customer deposits as a reduction to the rate base and the company to recover the interest paid to the customers as an interest expense.

**MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010**

LEVEL OF DEFERRED GENERATION COSTS EXCLUDING THE BIG STONE II COSTS

Deferred generation costs included by company in rate base \$ 172,000

Advocacy Staff Proposed Amount \$0.00 ^{REF} Note 1

Proposed Adjustment Amount by Advocacy Staff \$ (172,000) Statement N, Page 19 of 23
NDPSC - 074 Response No. 74, Attachment B, Page 1 of 3
Note 1

Note 1

These costs were incurred between 2006 and 2009. The company had sufficient earnings during this period to write these amounts off as expenses. Additionally, the company did not come and seek prior authorization to book this as a regulatory asset until June 2009. The company waited until June 2009 to submit a letter to the Commission Staff and later decided not to follow through as they filed this rate case. When the utilities incur substantial expenses which meet the used and useful criteria and where the current revenue is not sufficient to cover such expenses, and when the company plans to recover in future rates, they obtain prior approval from the respective Commission. The company did not follow this practice. The current request represents a retroactive ratemaking by the company. It is not a normal regulatory practice allowed by the Commissions across the country. Company made management decisions to enter into several generation related contracts and to withdraw from those contracts based on their assessments and decisions. The Commission nor the customers should be responsible for every decision made by the management. These were expenses that could have been written off the year when they made the decision not to proceed further. Since the company did not set up an authorized regulatory asset for this purpose, the company should have and would have expensed these items for financial and accounting purposes, when incurred. Unless, the company had the authorization from the Commission there was no FERC precedence or rules to set it up as a regulatory asset.

**MONTANA-DAKOTA UTILITIES CO.
 RATE BASE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

LEVEL OF WIND FARM ADIT

Total Wind Farm ADIT included in jurisdictional rate base by company \$34,000

Total Proposed Wind Generation (2010) ADIT \$3,275,000

Advocacy Staff Proposed Adjustment \$3,241,000

REF

NDPSC-075 Response
 No. 75, Attachment A,

Page 1 of 1

Note 1



Note 1

Accumulated deferred income taxes as filed by company	\$49,973,000
Wind generation (2010) related ADIT included in the filing	\$34,000
Based upon advocacy staff's inquiry of DR-075 response	
Wind generation (2010) related ADIT	\$3,275,000
Additional ADIT proposed by advocacy staff	\$3,241,000

**MONTANA-DAKOTA UTILITIES CO.
 UTILITY CAPITAL STRUCTURE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

Capital Structure with Company's Original ROE Request

	<u>Balance</u>	<u>Ratio</u>	<u>Cost</u>	<u>Required Return</u>
Long Term Debt	\$280,502,591	45.662%	6.845%	3.126%
Short Term Debt 1/	1,880,548	0.306%	11.590%	0.035%
Preferred Stock	15,600,000	2.540%	4.594%	0.117%
Common Equity	316,314,714	51.492%	11.500%	5.922%
Total	<u>\$614,297,853</u>	<u>100.000%</u>		<u>9.200%</u>

Projected 2010 ROE Agreed by Parties

	<u>Balance</u>	<u>Ratio</u>	<u>Cost</u>	<u>Required Return</u>
Long Term Debt	\$280,502,591	42.232%	6.845%	2.891%
Short Term Debt 1/	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%	10.750%	5.622%
Total	<u>\$664,200,141</u>	<u>100.000%</u>		<u>8.699%</u>

Projected 2010 ROR including Bond Redemption Loss

	<u>Balance</u>	<u>Ratio</u>	<u>Cost</u>	<u>Required Return</u>
Long Term Debt	\$280,502,591	41.756%	6.845%	2.858%
Unamortized Loss on Bond Redemption**	\$7,555,571	1.126%	6.845%	0.077%
Short Term Debt 1/	20,829,409	3.101%	2.535%	0.079%
Preferred Stock	15,500,000	2.306%	4.590%	0.106%
Common Equity	347,368,141	51.710%	10.750%	5.559%
Total	<u>\$671,761,289</u>	<u>100.00%</u>		<u>8.679%</u>

1/ Reflects average monthly balance.

**

The unamortized loss on debt of \$4,555,571 should appropriately be part of cost of debt, rather than being considered as a separate cost of service item in the rate base and in the income statement. Including it in the rate base to earn a return and in the income statement as an expense would make the customers pay a full return for a debt cost. Therefore, it is appropriate to consider this unamortized loss on bond redemption as a cost of debt financing. Therefore, the advocacy staff is also removing \$459,510 as included by the company as part of a ten year amortization in the income statement. Instead now the company is allowed to recover this as a part of the total cost of

**MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010**

COST OF FUEL FOR RESALE

		<u>REF</u>
Cost of fuel and purchased power for Sales for Resale	\$ 1,063,438	WPM-1
Advocacy Staff Proposed Amount	\$0.00	
Proposed Adjustment Amount	\$ 1,063,438	Note 1

Note 1

This adjustment is to reflect the matching cost of fuel used to generate Sale for Resale revenues.

**MONTANA-DAKOTA UTILITIES CO.
 LABOR EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

BONUSES, COMMISSIONS, AND INCENTIVE COMPENSATIONS

				<u>REF</u>
Labor Expense:				
Bonuses and Commissions				
				Response to 09/07/10
Amount included in test year for Bonuses and Commissions	1.0032	\$ 864,645	\$ 867,412	Conference Req, No. 6
	(864,465 + .32% increase)			
Staff Proposed Amount			\$ 346,965	IS 8
Advocacy Staff Proposed Adjustment	60%	\$ 867,412	\$520,447	Note 1
Incentive Compensations				
				Response to 09/07/10
Amount included in test year for Incentive Compensations	1.0032	\$ 1,041,756	\$ 1,045,090	Conference Req, No. 6
	(864,465 + .32% increase)			
Staff Proposed Amount			\$ 418,036	IS 8A
Advocacy Staff Proposed Adjustment	60%	\$ 1,045,090	\$627,054	Note 1

Note 1

These changes were recommended by Advocacy Staff to be shared 60% by stockholders and 40% by ratepayers. The Company wrote off in 2009, for tax purposes, but want to defer (amortize) over 3 years. Incentive pays are more to the advantage of stockholders and helps more the financial condition of the stockholders. There are certain benefits to ratepayers from a better performing company. Therefore the ratepayers should share in the costs. We recommend 60/40 split between shareholders and ratepayers respectively.

MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010

LABOR EXPENSE ANNUALIZATION

		REF	
		Conf. DR Response No.	
		13, Attachment A, p. 1	
Straight time labor annualization/For the twelve months ending July 2010	\$ 13,243,000	of 2	Adv.Staff Recomm
Premium time labor annualization/For the twelve months ending July 2010	\$ 1,065,000		
Bonuses & Commissions**	\$ 346,965		
Incentive Compensation**	\$ 418,036		\$ 15,136,001
Meals annualized for twelve months ending July 2010	\$ 33,000		\$ 16,555,000
Vacation annualized for twelve months ending July 2010	\$ 30,000		\$ (1,418,999)
Advocacy Staff Proposed Annualized Labor 2010	\$ 15,136,001		271499
			\$ (1,147,500)
Total labor included by company in projected test year 2010	\$ 16,555,000		
Adjustments IS 8 & 8A for Bonuses & Incentives	\$ (1,147,501)		
Advocacy Staff Proposed Labor Adjustment	\$ (271,499)		

Labor Expense:				
Bonuses and Commissions				
Amount included in test year for Bonuses and C	1.0032	\$ 864,645	\$ 867,412	
Advocacy Staff Proposed Amount	60%	\$ 867,412	\$520,447	\$ 1,147,501
Staff Proposed Adjustment Amount		\$ 346,965	**	\$ 1,418,999
Incentive Compensations				
Amount included in test year for Incentive Com	1.0032	\$ 1,041,756	\$ 1,045,090	
Advocacy Staff Proposed Amount	60%	\$ 1,045,090	\$627,054	\$ 271,498
Staff Proposed Adjustment Amount		\$ 418,036	**	

Note 1

It is the opinion of the advocacy staff that the performance based incentives are beneficial to both stockholders and ratepayers. Also, Staff believes that the savings from the performance enhancements should pay for the related incentive payments itself. However, recognizing the benefits in better performance by employees to the company as a whole and its customers, we propose the Commission should allow 40% of the cost in Cost of Service.

**Based on 40% actual included by company in projected test year 2010

**MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

CORPORATE ALLOCATIONS TO NORTH DAKOTA ELECTRIC

		<u>REF</u>
		DR 076 response, attachment A, p.
Investor Relations 7224/Investor relations subcontract	\$ 3,403	1 of 3
Active Director Fee 7231/Active Director Fee	\$ 70,131	
Retired Director Fee 7232/Retired Director Fee	\$ 2,486	
7233 Directors Meal and Entertainment	\$ 1,637	
Utility Discount	\$ 2,449	statement IV, p. 13; DR / 0,
		Attachment A p. 1 of 3, DR 72 On-
Insurance Amortization*	\$ 59,248	site No. 20
*For injuries and damages for Directors and Officers, First Layer A		Sept 7, 05 20
	50% \$ 139,354	
Advocacy Staff Proposed Amount	\$69,677	
Advocacy Staff proposed Adjustment Amount	(\$69,677)	IS 10

Note 1

These are common expenses that benefits ratepayers and stockholders, therefore it should be borne by both ratepayers and stockholders, and should be shared on a 50/50 basis. Therefore advocacy staff recommends removal of \$77,881.

**MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

**WESTERN AREA POWER ADMINISTRATION (WAPA)
 ADDITIONAL 2009 TRANSMISSION**

REF

Montana Dakota Charges Book	750,000	DR 14, Repsonse No. 19
2010 Projected Amount needed as revised estimate	250,000	
Proposed Advocacy Staff Adjustment Amount	500,000	
North Dakota Jurisdictional	65%	NOTE 1
Transmission Expense	(325,000)	IS 11

NOTE 1

Montana Dakota accrued \$750,000 at the end of 2009 for Western Area Power Administration (WAPA) additional transmission charges, based on its transmission service agreement effective January 1, 2009. In January through May the company accrued a monthly expense of \$67,000 for a total of \$325,000, based on an updated estimate received in June 2010, the annual estimate for 2009 was revised to \$100,000 and estimated \$250,000 for 2010. In June 2010, Montana Dakota recorded an adjustment to two of the 2009 accrual to \$100,000 from \$750,000 and reduced the monthly accrual for 2009 from \$67,000 to \$20,833 for a total adjustment of \$880,000 (\$650,000 + \$230,000). For 2009 alone, which is included in the test period the advocacy staff proposes \$500,000 total company with \$325,000 (65% jurisdictional) charge to North Dakota. There could be additional adjustments proposed by the advocacy staff for the 2010 accrual if it is included in the current rate filing.

**MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

COYOTE GENERATION MAINTENANCE

Coyote		<u>REF</u>
Total Generation Expense for 2007 - 2009	4,642,051	Sept on-site visit #1 Response No. 52
(3 year) Average per year	1,547,350	
Test Year	<u>2,000,799</u>	Note 1
Advocacy Staff proposed Adjustment Amount	(453,449)	IS 12

Note 1

The average Coyote generation maintenance expense for 2007 through 2009 was \$1,547,350. The test year amount was \$2,000,799, which was high due to special, periodically scheduled, maintenance. Therefore, in order to normalize the test year expense the Advocacy Staff proposes a reduction of \$453,449 from the projected test year expenses.

**MONTANA-DAKOTA UTILITIES CO.
OPERATION & MAINTENANCE EXPENSE
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010**

BIG STONE GENERATION MAINTENANCE

Big Stone		<u>REF</u>
Total Generation Expense for 2007 - 2009	2,813,872	Sept on-site visit #1 Response No. 52
(3 year) Average per year	937,957	
Test Year	780,094	
Advocacy Staff proposed Adjustment Amount	157,863	\$15

Note 1

The average Big Stone generation maintenance expense for 2007 through 2009 was \$937,957. The test year amount was \$780,094, which was lower. Therefore, in order to normalize the test year expense the Advocacy Staff proposes an increase of \$157,863 from the projected test year expenses

**MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

STORM COSTS OF 2010

Cost as of December 2009
 Dickinson 2009 Storm Damage

	Expense	Work Order Description	Bus Unit	SubLedger
	50,985.93	DKN Storm Damage Ele Dist Exp	150	165844
	<u>5,729.18</u>	DKN Storm Damage Ele TL Expens	TL408-1	165846
Total Expense	56,715.11			

REF

Per DR Response No. 39 ND Amort Expenses Only
 56,715 * 65% \$ 36,865 Already in rates

January 2010 Storm

Per DR Response No. 92
 457,074 \$ 160,140 DR Response No. 92

April 2010 Storm

Per DR Response No. 92

ND Distribution	\$ 111,063	\$	111,063	DR Response No. 92
ND Transmission	\$ 292,876	\$	<u>190,364</u>	DR Response No. 92 Applied 65% to ND
Subtotal 04/2010	\$ 403,939	\$	301,427	DR Response No. 92

ND Total Storm Expense 2009/2010 \$ 498,432

3 year proposed
 amortization period
 by Advocacy Staff \$ 3

Annual Amortization \$ 166,144

Amount Included in Test Year (2009) \$ 36,865

Advocacy Staff Proposed IS Adj \$ 129,279

Note 1

The Company does not have a habit of separately accounting for storm costs as an extraordinary event expenses. However, advocacy staff believes that these are unusual and overly burdensome expenses caused by nature which is beyond the control of the company. FERC requires utilities to identify and account for these expenses separately. We believe that in 2010, the company had two storm expenses in January and April. Advocacy Staff segregated these expenses and asking the company to recover it over a three year amortization. The company did not request for any special recovery treatment even though it happened in 2010. Advocacy Staff proposed an increase in O&M expenses of \$129,279 to cover such expenses.

**MONTANA-DAKOTA UTILITIES CO.
 OPERATION & MAINTENANCE EXPENSE
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

ADJUSTMENTS TO O&M

	Diamond Willow	Cedar Hills
	\$ 279,000	\$ -
	\$ 63,149	\$ -
	\$ 87,310	\$ 157,392
	\$ 429,458	\$ 157,392

	REF
	Response DR No. 91
\$ 279,000	
\$ 63,149	DR No. 52, Attachment B, p. 1
\$ 244,702	DR No. 52, Attachment C, p. 1
\$ 586,850	IS 15

	Note 1
\$ 16,693	WP Statement H, p. 3
\$ 4,536	**
\$ 21,229	IS 16

Corporate Aircraft O&M (subsection A&G) account 921

7512 Corporate Aircraft

***This amount is from the corporate allocation amount for corporate aircraft

\$ 48,450	WP Statement M, p. 138
\$ 34,000	WP Statement M, p. 138
\$ 52,000	Statement M, p. 39
\$ 134,450	IS 16
\$ 721,300	Total

\$ 17,287	
\$ 34,000	
\$ 52,000	
\$ 103,287	
\$ 532,745	Total

LEVEL OF DEFERRED GENERATION COSTS EXCLUDING THE BIG STONE II COSTS

Proposed Adjustment Amount

\$ (172,000)

Statement N, Page 19 of 23
 NDPSC-074 Response No. 74,
 Attachment B, Page 1 of 3

Note 1 --Deferred Generation Costs (IS-5)

These costs were incurred between 2006 and 2009. The company had sufficient earnings during this period to write these amounts off as expenses. Additionally, the company did not come and seek prior authorization to book this as a regulatory asset until June 2009. The company waited until June 2009 to submit a letter to the Commission Staff and later decided not to follow through as they filed this rate case. When the utilities incur substantial expenses which meet the used and useful criteria and where the current revenue is not sufficient to cover such expenses, and when the company plans to recover in future rates, they obtain prior approval from the respective Commission. The company did not follow this practice. The current request represents a retroactive ratemaking by the company. It is not a normal regulatory practice allowed by the Commissions across the country. Company made management decisions to enter into several generation related contracts and to withdraw from those contracts based on their assessments and decisions. The Commission nor the customers should be responsible for every decision made by the management. These were expenses that could have been written off the year when they made the decision not to proceed further. Since the company did not set up an authorized regulatory asset for this purpose, the company should have and would have expensed these items for financial and accounting purposes, when incurred. Unless, the company had the authorization from the Commission there was no FERC precedence or rules to set it up as a regulatory asset. Therefore, we recommended the Commission to disallow this expense.

**MONTANA-DAKOTA UTILITIES CO.
 PRODUCTION TAX CREDIT
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010**

NDPSC Case No. PU-10-124
 Schedule GM-4-20
 GM PRODUCTION TAX CREDIT--WIND

Scenario 1

	Projected 2010	Advocacy Staff 2010	Diamond Willow	Cedar Hills
<u>Generation - Kwh</u>				
Cedar Hills	64,700,000	66,619,800	\$ 499,169	\$ 899,847
Diamond Willow	99,500,000	102,492,000	\$ 2,152,332	\$ -
Total	164,200,000	169,111,800	\$ 2,651,501	\$ 899,847
Production Tax Credit	(\$0.021)	(\$0.021)		
Total Production Tax Credit	(\$3,448,200)	(\$3,551,348)		\$ 0.3778890
Allocated to North Dakota 1/	(\$2,237,491)	(\$2,304,422)		

1/ Allocated on Kwh sales factor.

Allocation Percentage KWH Sales - Factor 16 64.888666%

**Montana-Dakota Utilities Co.
 Case No. PU-10-124
 Wind Farm Allocation Scenarios**

Description	Diamond Willow	Cedar Hills	Total
Diamond Willow Wind Farm (MW's)	30.0	-	30.0
Cedar Hills Wind Farm (MW's)	-	19.5	19.5
Total Wind (MW's)	30.0	19.5	49.5
Capacity Factor	39%	39%	39%
Days in a Year	365	365	365
Hours in a Day	24	24	24
Estimated Energy from Wind Farms (mWh's)	102,492.0	66,619.8	169,111.8
Estimated Energy from Wind Farms (kWh's)	102,492,000.0	66,619,800.0	169,111,800.0
MDU Energy Sales (kWh's)			
Renewable Objective / Standard	1,577,853,225	700,394,000	700,394,000
Renewable Energy Goal / Mandate (kWh's)	157,785,323	70,039,400	105,059,100
	North Dakota	Montana - 10%	Montana - 15%

MONTANA-DAKOTA UTILITIES CO.
 PLANT IN SERVICE AND ACCUMULATED DEPRECIATION
 ADVOCACY STAFF POSITION
 ELECTRIC UTILITY - NORTH DAKOTA
 PROJECTED 2010
 (000s)

	Plant in Service Per Books Plant	Accumulated Depr Per Books North Dakota	Plant in Service Projected 2010	Accumulated Depr Projected 2010
Plant in Service				
Steam Production	\$202,968,849	\$129,748,842	\$206,498	\$134,092
Other Production	58,847,038	10,776,668	105,704	15,380
Total Production	\$261,815,887	\$140,525,510	\$312,202	\$149,472
Transmission	92,482,990	51,624,661	109,050	53,529
Distribution	131,372,493	64,644,951	143,227	67,264
General	12,625,103	6,192,571	13,528	6,382
Intangible Plant - General	4,022,989	3,313,779	4,023	3,625
Common	16,489,655	9,070,745	16,995	8,876
Intangible Plant - Common	8,875,787	6,206,367	9,036	6,662
Subtotal	527,684,904	281,578,584	608,061	295,810
Acquisition Adjustment	7,161,943	6,525,036	7,162	6,683
Total Plant in Service	\$534,846,847	\$288,103,620	\$615,223	\$302,493

Difference between 2010 and 2009 is \$1,477,000 (W/P)

MONTANA-DAKOTA UTILITIES CO.
EMPLOYEE BENEFITS EXPENSE
ADVOCACY STAFF POSITION
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2010

BENEFIT EXPENSE ANNUALIZATION

	MDU Filing	REF
		<u>Conf. DR Response No. 13,</u>
		Attachment A, p. 1 of 2
Medical/Dental-For the twelve months ending July 2010	\$ 1,636,000	
Pension Expense/For the twelve months ending July 2010	\$ 577,000	
Post Retirement	\$ 344,000	
401K	\$ 1,176,000	
Worker's Compensation	\$ 53,000	
Advocacy Staff Proposed Annualized Benefit Expense 2010	\$ 3,786,000	

Total Benefits expense included by company in projected test year 2010

Advocacy Staff Proposed Amount

NO ADJUSTMENT