EXHIBIT 16
DATE 4-11-05
SB SB415

A COMPARISON OF PROJECTED WIND POWER COST TO THE COST OF POWER ON THE NORTHWESTERN AND MONTANA-DAKOTA SYSTEMS

NorthWestern Energy (formerly The Montana Power Company) sold its generating facilities following its embrace of electric utility deregulation in Montana. Montana-Dakota successfully avoided the deregulation fiasco, by obtaining an exemption from the 1997 Dereg Act, and still owns its own generating facilities.

Wind energy looks more attractive on the NWE system than the MDU system, because it is competing against a much higher cost of power on the NWE system. On the NWE system, alternate energy resources compete against the market price of wholesale power, projected by the Montana Public Service Commission to be $41.20/Mwh in 2004/2005. On the MDU system, alternate energy competes against the cost of running MDU's existing generating stations, which in 2008 is projected to be $20.57/Mwh.

While the projected cost of wind power from a 30 MW facility might be less than the PSC projected wholesale cost of power to NWE, it is significantly more than the cost of power from MDU's own generation.

$57.60	Estimated cost of wind power from a 30 Mw wind farm. [Assuming: (1) that the $18 Mwh tax credit is not extended by the federal government, or is captured by the wind developer because of bargaining leverage under SB 415; and, (2) the required ancillary services can be purchased for $4.60/Mwh]
$41.20	PSC estimated cost of power to **NWE** in 2004/2005.
$39.60	Estimated cost of wind power from a 30 Mw wind farm. [Assuming: (1) that the $18/Mwh tax credit is extended by the federal government, and passed on to the buying utility; and, (2) the required ancillary services can be purchased for $4.60/Mwh]
$20.57	Estimated cost of generating power in **MDU** owned generating stations in 2008.

FOR THE MDU CUSTOMER, WIND ENERGY IS MUCH MORE EXPENSIVE THAN THE COST OF POWER FROM MDU'S OWN GENERATING FACILITIES.

MONTANA-DAKOTA UTILITIES CO.
Analysis of
Ratepayer Impacts
of
Senate Bill 415

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. owns its own generating facilities, which are located in Montana, North Dakota, and South Dakota. Its generating facilities in Montana have a peak generating capability of 150 megawatts. The peak demand of its Montana customers is 113 megawatts, and its average Montana load runs between 65 and 70 megawatts.

Senate Bill 415 would force Montana-Dakota to buy about 30 megawatts of new generating resources which it doesn't really need in Montana, at additional expense to its Montana ratepayers. To comply with Senate Bill 415, Montana-Dakota would have to acquire renewable energy, and generate less energy at its existing generating stations. Since its existing facilities can generate power much more cheaply than the power that will be provided by the new generating resources required by Senate Bill 415, the result would be a rate increase to the Montana-Dakota ratepayer. If it is assumed that wind is the most likely renewable resource in the Montana-Dakota service territory, and that the current tax credit for wind developers is either not extended by Congress, or is captured by the developer, the rate increase caused by Senate Bill 415 could be in the range of 10% to 12%. I have attached a work sheet which shows how we estimated the size of the rate increase, and the assumptions we used in doing the calculations.

WORK SHEET

Assumptions;

1. Current cost of power from a 30 megawatt wind farm is about $53 per megawatt hour. [Tax credit equates to about $18 per megawatt hour. If developer had to pass on tax credit to make resource more cost effective, cost to utility would be about $35]

2. Wind power requires the purchase of ancillary services, at an approximate cost of $4.60 per megawatt hour. [Total cost of wind power is $57.60 per megawatt, if developer keeps tax credit.]

3. Wind power is not firm power, so utility will still have to acquire firm generating capacity to meet customer requirements.

4. The net cost of wind power to the utility and its ratepayers is the cost paid for the wind power less avoided fuel costs from traditional generation.

5. Annual avoided fuel costs, wind purchases, and wind revenue requirements will be:

				Annual Revenue Requirement
2008	$	20.57	32,000	$ 1,184,969.65
2009	$	21.07	32,320	$ 1,180,659.22
2010	$	21.79	65,287	$ 2,337,925.03
2011	$	17.83	65,940	$ 2,622,425.89
2012	$	15.97	66,599	$ 2,772,524.66
2013	$	17.32	67,265	$ 2,709,441.90
2014	$	16.65	67,938	$ 2,782,054.67
2015	$	17.01	102,926	$ 4,177,759.53
2016	$	16.92	103,955	$ 4,228,893.08
2017	$	18.45	104,995	$ 4,110,540.21

Total Montana electric revenues were $40 million in 2003 (hot year) and $36 million in 2002 (cooler year). The annual revenue requirement for wind purchases at 15% of sales requirement (Year 2015) is $4.2 million or 10.5% of 2003 revenues and 11.66% of 2002 revenues.

15. In terms of resources for the 2004/2005 tracking year, the portfolio retains the 300 MW base-load and 150 MW unit-firm-on-peak resources from PPL Montana as well as the unit-contingent Qualifying Facility (QF) resources. In addition NWE has included 102,960 MWh from the Thompson River Co-Gen project and 18,120 MWh from Tiber Dam in the forecast. The rest of the resources will be procured as needed, in the short-term market (twelve months and less). Net short-term transactions are projected to be 28 percent (1,706,560 MWh) of the total resources necessary to meet load.. The reliance on short-term purchases results in a fairly high degree of exposure to market volatility risk.

16. The 2004/2005 projection includes approximately $1.7 million of Demand Side Management (DSM) program costs and corresponding lost revenues. Also included in Administrative Expenses are labor costs related to the DSM Project Coordinator and $820,000 of Montana Consumer Counsel (MCC) and Public Service Commission (PSC) funding fees that were not included in prior tracking filings.

17. The projected unit cost of electricity during the 2004/2005 tracking period is $41.06 (including losses), an increase of approximately 9 percent over the energy rate in the 2003/2004 tracking period. In addition, there is a $.14 per MWh cost to cover the net under collection from the 2002/2003 and 2003/2004 tracking periods, making a projected total supply-related unit cost of $41.20 per MWh. This rate is a projection of costs over the next twelve months given existing market conditions. NWE will attempt to optimize market opportunities in order to mitigate costs throughout the year and cost estimates will be updated in subsequent monthly trackers. NWE files a strategy report with each monthly tracker to provide insight into market conditions and procurement activity. In July, 2003, NWE projected the upcoming twelve-month cost to be $40.52 per MWh, while the actual cost for the twelve-month tracking period was $37.56 per MWh.

Commission Analysis and Discussion

Electric Supply Deferred Cost Account Balance:

18. The Commission notes that since the last case the Company has reevaluated its position on the appropriate treatment of the July 2002 revenues. In this filing the Company has concluded that a full month of July 2002 supply revenues should be included in this adjustment.