Memo

To: Darrell Nitschke, Executive Secretary

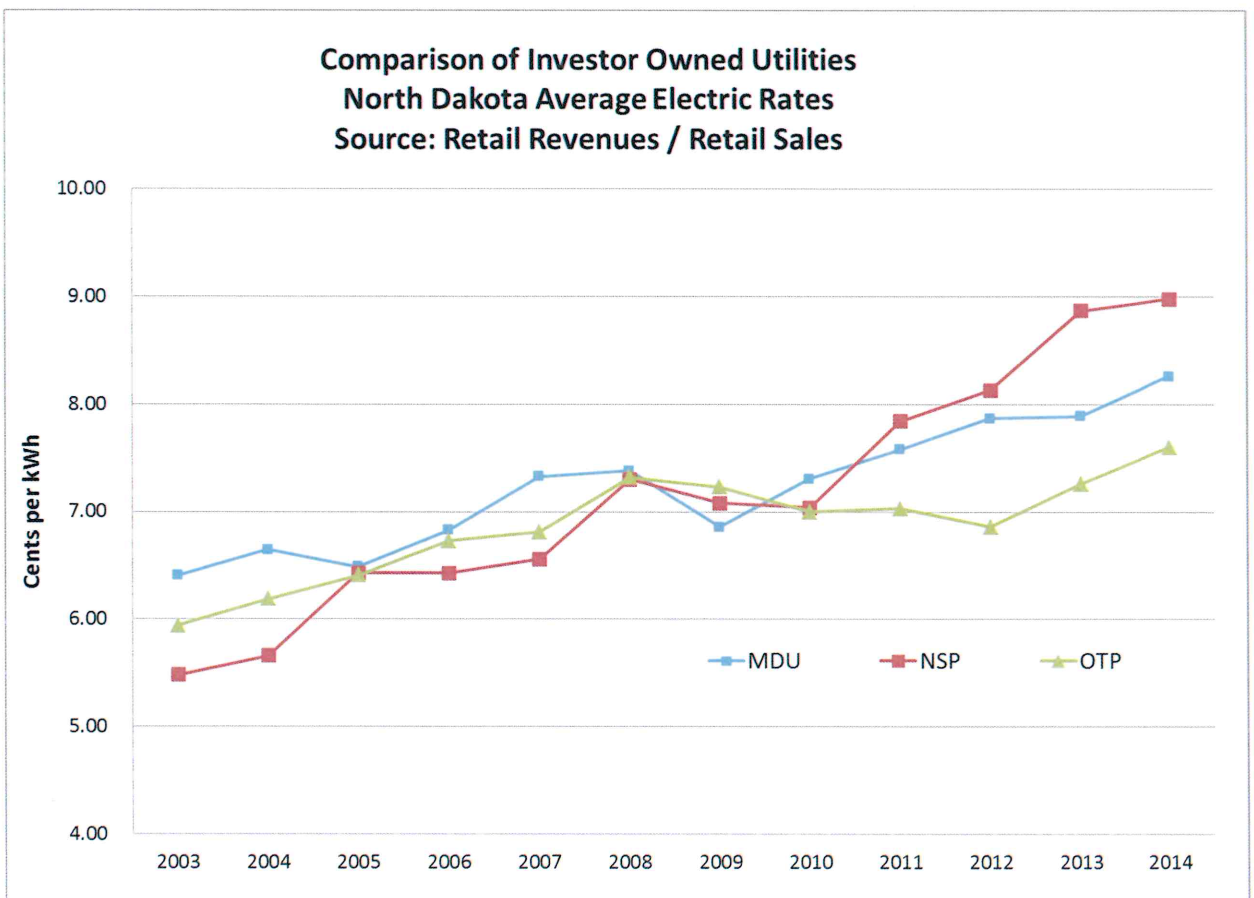
From: Mike Diller

Date: February 23, 2016

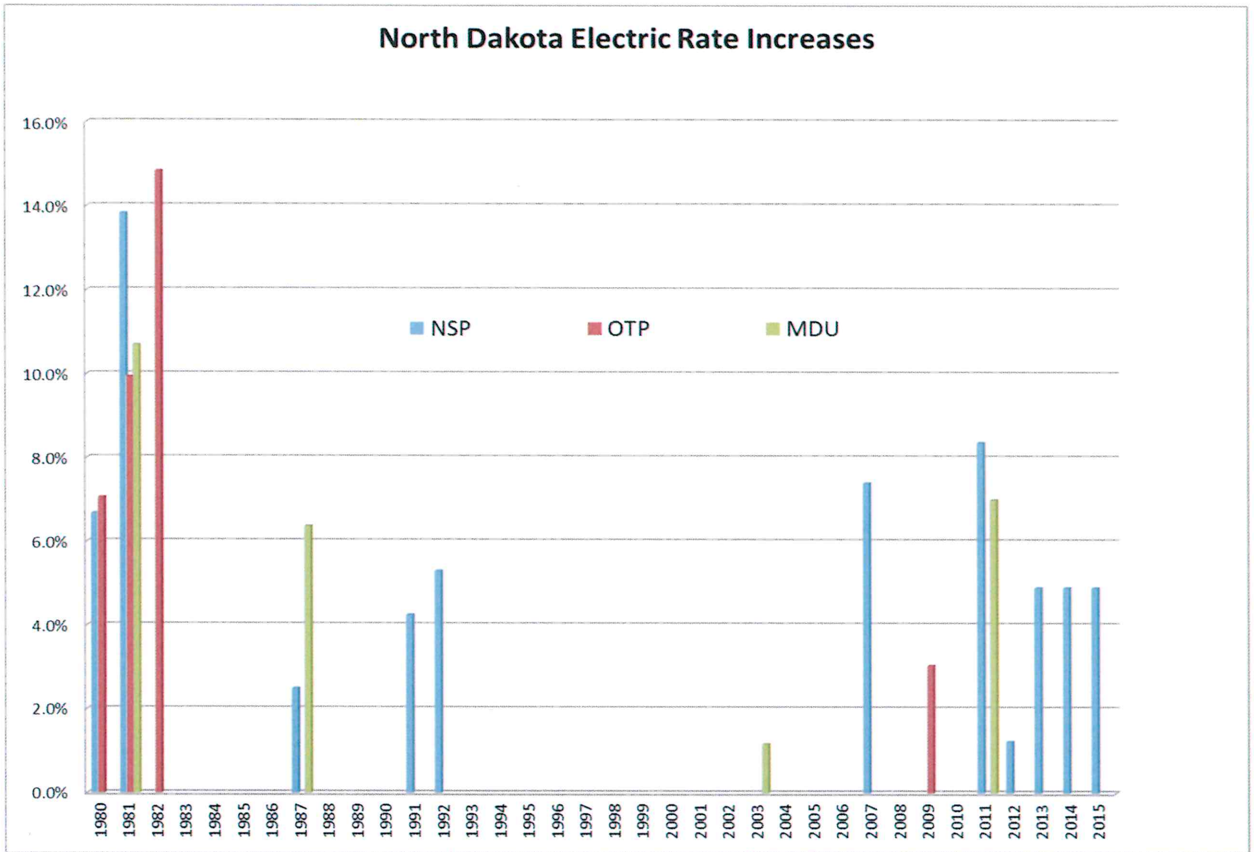
Re: **Close NSP's 2011 – 2014 Electric Annual Reports**
Case Nos. PU-12-811, PU-13-209, PU-14-589, PU-14-746

I have reviewed Northern States Power (NSP) Company's Electric Annual Reports and recommend the cases be closed in accordance with commission policy 5-05-97. I am providing this to Dave Sederquist in the event NSP would like to comment on my recommendation. Staff will allow until March 11 for receiving comments before preparing a motion to close the cases.

The primary focus of this report is on rates; although the customary revenue deficiency schedules are included later in the memo. The focus on rates is driven by concern over the divergence of rates between NSP and those of the other two investor owned utilities operating in North Dakota.

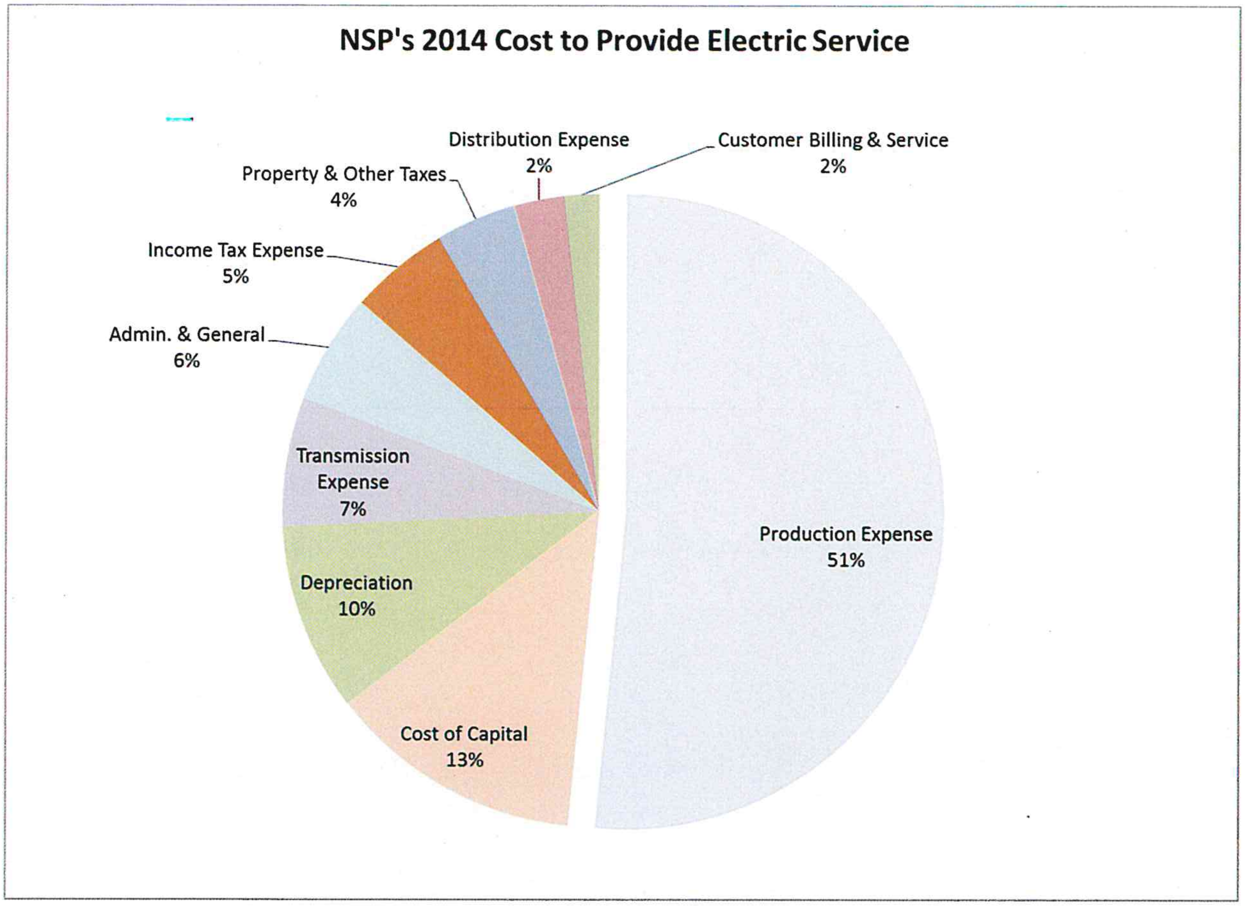


The focus on rates rather than earnings is also occurring because NSP has received multiple rate increases in recent years. Accordingly, revenue deficiency calculations have been reviewed quite extensively and it would make little sense to do so here given that NSP's rates are frozen through 2016; potentially through 2017 should the commission accept the pending Negotiated Agreement between staff and NSP.



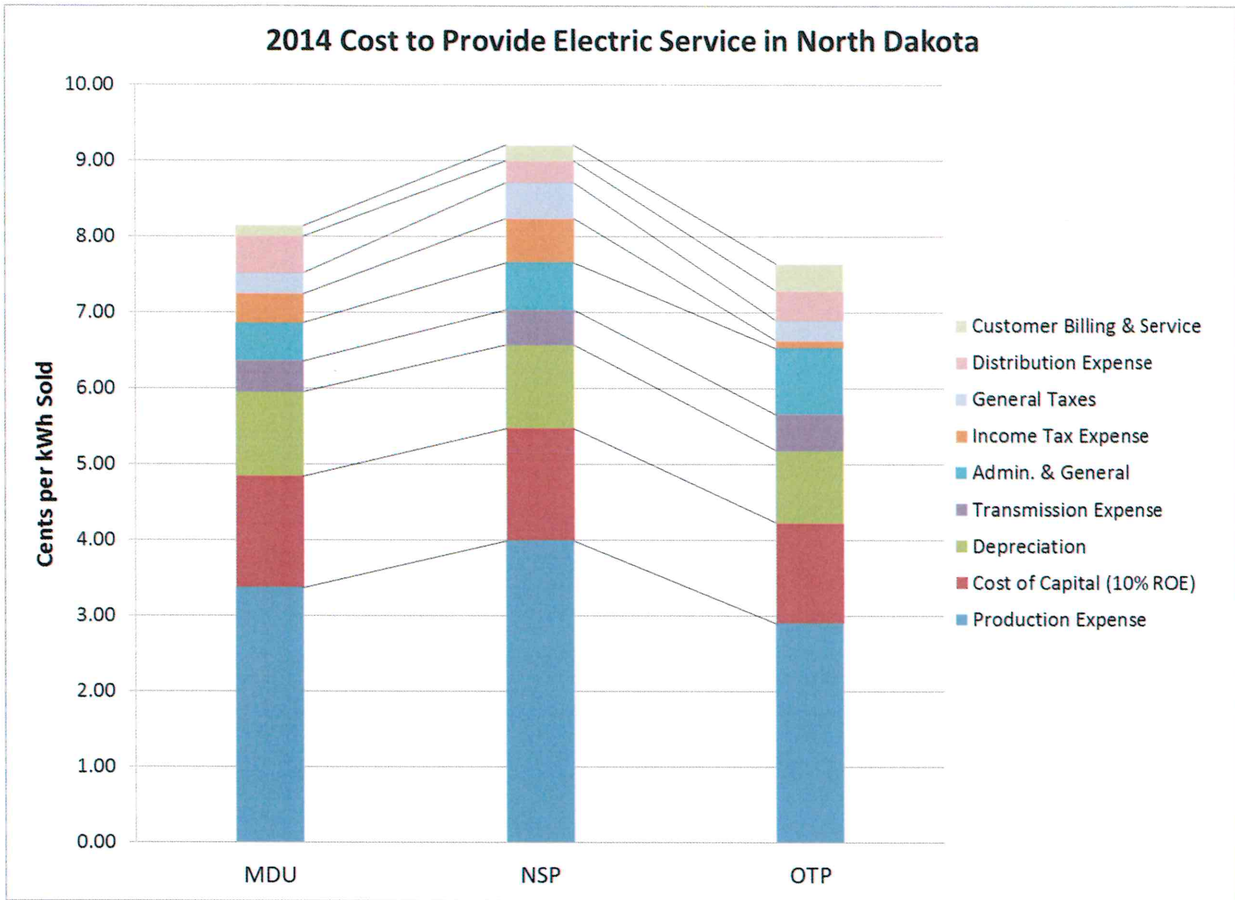
Over the years, NSP Electric consumers enjoyed a long period of stable base rates; but that has changed in recent years. Before 2011, NSP's base rates increased only once since 1992. That has changed as NSP began investing in large transmission and generation projects to meet renewable standards, strengthen the regional transmission grid and generally refurbish older plant. Rates are impacted by rate increases and NSP's base rates have increased every year since 2010.

Rates are also impacted by riders such as the cost of energy adjustment, transmission rider, renewable rider and the like. NSP's primary rider surcharge has been the cost of energy adjustment. The cost of energy adjustment is comprised of fuel costs and purchased power costs. These large expenses are included in Production Expense which makes up 51% of NSP's 2014 cost to provide service compared to 38% for Otter Tail Power Company (OTP) and 42% for Montana-Dakota Utilities Co. (MDU).



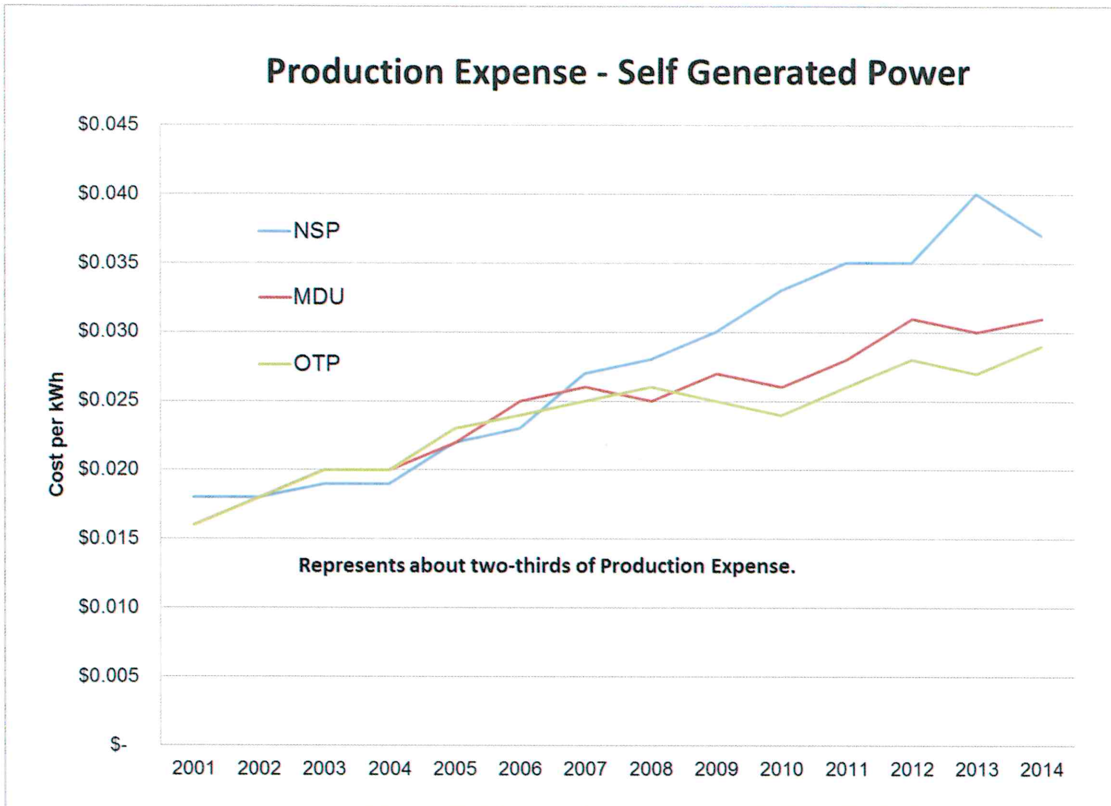
Rates are ultimately affected by the utilities' total cost to provide service. Therefore, staff developed the following comparison on a kWh basis using the most recent annual report (2014) to help define the impact of each cost category on the average cost of energy. For comparative purposes, a 10% return on equity was used for all three utilities companies.

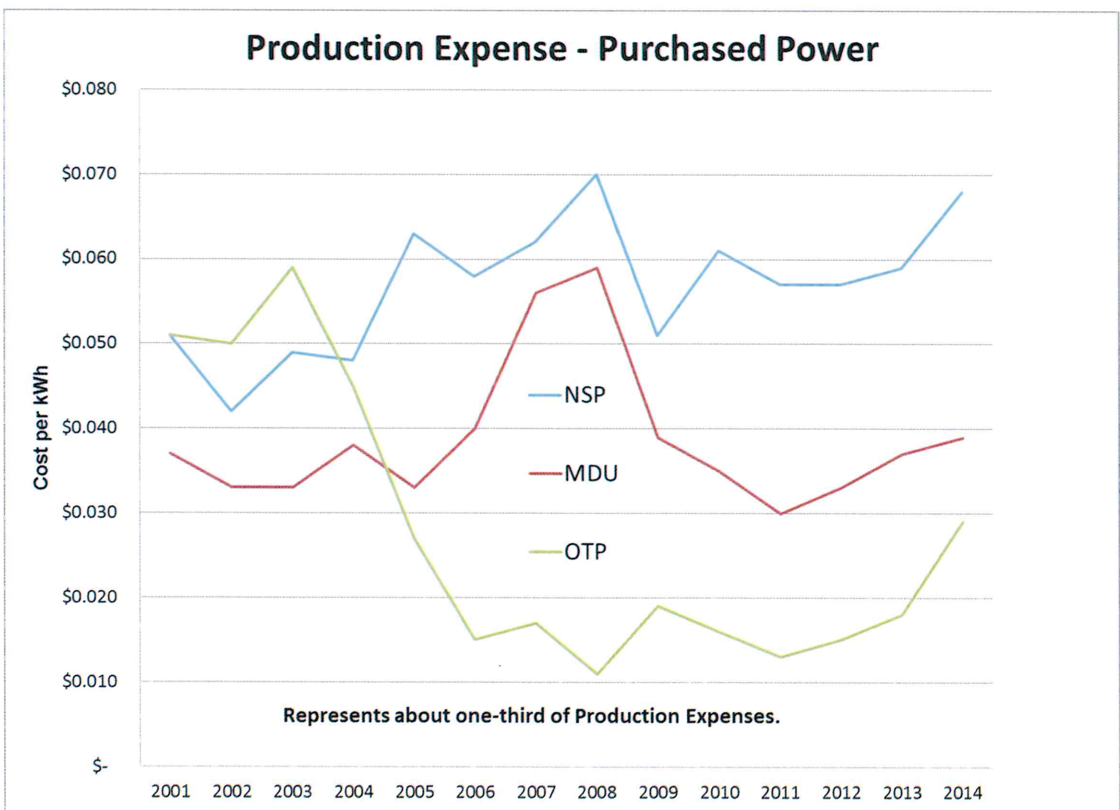
While the cost comparison is fairly straightforward, it was necessary to reduce some of the expense categories for miscellaneous revenues in depicting net cost of service. For instance, revenues received from MISO for wheeling fees are credited against transmission expense. Sales for resale were credited against production expense. Rental income was credited to Admin & General. Not all adjustments were clear and straightforward but made little difference in the overall cost comparison analysis, as follows:



As you can see, the primary cost difference on a kWh basis resides in the cost of Production. Before attending to those differences, note that OTP is a much smaller corporation than MDU and NSP and so it does not enjoy the same economies of scale. This is seen rather forcefully in Customer Billing & Service and Administration and General expenses. OTP continues to conduct manual meter readings to maintain a presence in its rural service area. OTP has been returning to its core business of selling electricity by selling some of its diversified interests; which leaves more A&G costs to be covered by the electric operations. Nevertheless, OTP continues to out-perform MDU and NSP in terms of the delivered price of electricity to end consumers.

Production Expense includes the cost to produce electricity as well as purchased power costs from other suppliers. The North Dakota annual report does not provide sufficient detail to analyze these two components and so staff used the 2014 FERC Form 1 filed by each of the companies with the Federal Energy Regulatory Commission to produce the next chart. There is some variability between the companies but roughly speaking, about one-third (28% to 39%) of the Production Expense is related to purchase power with the remaining two-thirds related to self-generated power (72% to 61%). Following are two graphs depicting these costs separately.


Production Expense - Self Generated Power
$0.045
$0.040
$0.035
$0.030
$0.025
$0.020
$0.015
$0.010
$0.005
$-
Cost per kWh
NSP
MDU
OTP
Represents about two-thirds of Production Expense.
2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014


Production Expense - Purchased Power
$0.080
$0.070
$0.060
$0.050
$0.040
$0.030
$0.020
$0.010
$-
Cost per kWh
NSP
MDU
OTP
Represents about one-third of Production Expenses.
2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014

Please note that OTP's purchase power costs are artificially low in recent years because it has operated an energy trading center through 2014. Because profits from energy trading are reflected as a reduction to purchased power costs; the net cost results in a lower than normal average price for OTP's purchased power costs. The trading center was closed at the end of 2014 so OTP's future purchased power costs will be on a more comparable basis with MDU and NSP.

In summary, NSP's rates are higher than MDU and OTP primarily because of its higher Production Expense. Production Expense makes up about one-half of NSP's cost to provide electric service. NSP's 2014 production expense for self-generation was 28% higher than OTP and 19% higher than MDU on a per kWh basis. Similarly, NSP's purchase power costs in 2014 were 74% more than MDU and more than twice that of OTP. NSP purchased 31% of its purchased power from MISO and the rest through other methods and contracts. In contrast, MDU and OTP purchased 90% and 51% of its purchased power from the MISO exchange, respectively; representing very low cost energy in recent years.

I write this to warn NSP and the commission that continuing down this path is not sustainable. If NSP continues to separate itself in terms of price from North Dakota's other investor owned utilities, the commission should take notice and attempt to alter that path. The commission has a wide range of solutions at its disposal including reducing the return on equity allowed in rate proceedings, eliminating incentive pay compensation and moving to alternative forms of regulation including price caps, performance-based regulation, rate moratoriums and the like.

Following are the customary schedules depicting NSP's electric earnings in North Dakota using the commission approved return on equity for each year.

Return on Equity & Revenue Deficiency Calculation
(Dollars In Thousands)

Line	Return on Equity	2011	2012	2013	2014
1	Operating Income from Operations	$ 24,951	$ 24,536	$ 29,471	$ 31,669
2	Average Regulated Rate Base	322,995	338,608	387,936	453,402
3	Rate of Return on Rate Base (L1/2)	7.72%	7.25%	7.60%	6.98%
4	Less: Weighted Cost of Debt	2.88%	2.61%	2.29%	2.23%
5	Return Remaining for Common Stock	4.84%	4.64%	5.31%	4.75%
6	% of Equity in Capital Structure	52.67%	52.78%	52.67%	52.87%
7	**Actual Return on Equity (L5/6)**	**9.18%**	**8.79%**	**10.08%**	**8.98%**

Line	Description	2011	2012	2013	2014
8	Rate Base	$ 322,995	$ 338,608	$ 387,936	$ 453,402
9	Rate of Return Allowed	8.36%	8.10%	7.42%	7.52%
10	Return Allowed (L1 x 2)	$ 27,006	$ 27,422	$ 28,799	$ 34,100
11	Return Earned	24,951	24,536	29,471	31,669
12	Return Deficiency (Excess)	$ 2,055	$ 2,886	$ (672)	$ 2,431
13	Tax Factor	1.6220	1.6220	1.6115	1.6115
14	**Revenue Deficiency (Excess)**	$ 3,332	$ 4,681	$ (1,083)	$ 3,918

Rate Base
(Dollars In Thousands)

Line	Description	2011	2012	2013	2014
1	Plant in Service	$ 742,545	$ 780,660	$ 873,044	$ 980,723
2	Accumulated Depreciation	364,662	379,380	412,555	445,595
3	Net Plant in Service	$ 377,883	$ 401,280	$ 460,489	$ 535,128
4	Construct Work in Progress	657	2,936	1,765	2,527
5	Materials and Supplies	7,213	7,471	8,461	9,305
6	Fuel Stocks	5,454	5,634	5,620	4,753
7	Prepayments	3,833	4,830	7,504	7,980
8	Customer Deposits	(15)	(29)	(186)	(179)
9	Other Rate Base [1]	(3,903)	(3,776)	(2,826)	96
10	Accum. Deferred Taxes	(68,127)	(79,738)	(92,891)	(106,208)
11	Total Average Rate Base	$ 322,995	$ 338,608	$ 387,936	$ 453,402

Cost of Capital
(Dollars In Thousands)

Line	Description	Amount	Capital Structure	Cost	Weighted Cost
	2011				
1	Long-Term Debt	$ 3,286,351	46.90%	6.12%	2.87%
2	Short-Term Debt	30,167	0.43%	3.06%	0.01%
3	Common Equity	3,690,284	52.67%	10.40%	5.48%
4	Total Capital	$ 7,006,802	100.00%		**8.36%**
	2012				
5	Long-Term Debt	$ 3,360,934	45.38%	5.71%	2.59%
6	Short-Term Debt	136,000	1.84%	0.98%	0.02%
7	Common Equity	3,908,649	52.78%	10.40%	5.49%
8	Total Capital	$ 7,405,583	100.00%		**8.10%**
	2013				
9	Long-Term Debt	$ 3,667,427	45.37%	5.01%	2.27%
10	Short-Term Debt	158,167	1.96%	0.77%	0.02%
11	Common Equity	4,257,356	52.67%	9.75%	5.14%
12	Total Capital	$ 8,082,950	100.00%		**7.42%**
	2014				
13	Long-Term Debt	$ 4,002,684	45.47%	4.89%	2.22%
14	Short-Term Debt	146,333	1.66%	0.65%	0.01%
15	Common Equity	4,653,572	52.87%	10.00%	5.29%
16	Total Capital	$ 8,802,589	100.00%		**7.52%**

Net Operating Income
(Dollars In Thousands)

Line	Description	2011	2012	2013	2014
1	Residential	$ 68,744	$ 69,329	$ 81,128	$ 81,066
2	Small Commercial & Inc	83,167	85,328	96,704	98,244
3	Large Commercial & Inc	21,516	22,301	23,654	24,600
4	Street & Public Auth.				2,953
5	Other[1]	40,456	42,928	48,572	51,034
6	Total Revenues	$ 213,883	$ 219,886	$ 250,058	$ 257,897
7	Production Expense	119,260	120,355	134,307	134,955
8	Gross Margins	$ 94,623	$ 99,531	$ 115,751	$ 122,942
9	Transmission Expense	11,219	12,309	14,921	17,224
10	Distribution Expense	6,737	6,387	6,784	6,727
12	Customer Billing	4,411	4,128	4,121	4,300
13	Customer Service	489	370	348	439
14	Sales & Marketing[3]	135	2	1	0
15	Admin. & General[4]	11,770	12,969	15,576	14,664
16	Depreciation	17,885	20,400	22,295	25,265
17	Property Taxes	5,881	6,690	7,917	8,727
18	Other General Taxes[2]	1,820	1,866	2,081	2,056
19	Income Tax Expense	9,325	9,874	12,236	11,871
20	Net Operating Income	$ 24,951	$ 24,536	$ 29,471	$ 31,669