5. Wind Curtailment Report (Docket Nos. E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85)

On July 17, 2002, the Commission issued Orders approving Xcel Energy's wind Power Purchase Agreements (PPA) with Chanarambie Power Partners, LLC and Navitas Energy, LLC (now Moraine Wind, LLC) in Docket Nos. E002/M-00-622 and E002/M-02-51. In addition to approving the PPAs, the Commission required the Company to report the date, length, cost to ratepayers, and reason for each transmission constraint curtailment with these two contracts in the monthly FCA filing and summarize such events in the Company's AAA reports.

Similar reporting requirements were instituted by the Commission in approving other wind PPAs.[1] The Company has been providing wind curtailment reporting in its monthly FCA reports since the May FCA report dated April 28, 2004.

Additionally, the Commission's Order of April 4, 2006 regarding curtailment payments to wind developers introduced a new element to the regulatory review of wind power purchases—projection of curtailment costs given existing and planned wind-generated energy purchases and the transmission system.

Part H, Section 5, Schedule 1 contains a summary of wind production and curtailment payments during the period July 1, 2014 through June 30, 2015.

Part H, Section 5, Schedule 2 contains an explanation of the factors affecting wind curtailment costs for the 2014-15 AAA reporting period, and our projection of expenses associated with wind curtailment for the next five years. The actual curtailment expenses will depend on the wind resource experienced at each turbine, the timing of outages of existing transmission facilities and construction of additional transmission facilities, and the operation of wind generators as Dispatchable Intermittent Resources (DIR) in the MISO energy market.

[1] See Docket No. E002/M-04-404, Order dated October 4, 2004 (approving the Ivanhoe PPA); Docket No. E002/M-04-864, Order dated December 29, 2004 (Velva Windfarm, LLC); Docket Nos. E002/M-05-1850 and E002/M-05-1934, Orders dated March 31, 2006 (Fenton Power Partners I, LLC and FPL Energy-Mower County, LLC); and Docket No. E002/M-06-85, Order dated May 3, 2006 (MinnDakota Wind, LLC).

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
For January 2013 to June 2015

	Date Paid		Wind Production Delivered		Lost Production		
Production Month	**Delivered MWh**	**Lost MWh**	**MWh Delivered**	**Amount Xcel Energy Paid**	**Lost MWh**	**Amount Xcel Energy Paid**	**Total Xcel Energy Paid**
Jan-13			414,433.00	$ 16,263,046.75	3,485.00	$ 99,847.03	$ 16,362,893.78
Feb-13			333,614.00	$ 13,025,644.94	2,305.00	$ 77,830.54	$ 13,103,475.48
Mar-13			345,786.00	$ 13,497,049.60	5,915.00	$ 241,878.53	$ 13,738,928.13
Apr-13			372,099.00	$ 14,548,304.09	18,127.00	$ 780,564.80	$ 15,328,868.89
May-13			371,018.00	$ 14,729,182.55	14,849.00	$ 443,050.30	$ 15,172,232.85
Jun-13			283,123.00	$ 11,128,472.51	8,913.00	$ 270,229.36	$ 11,398,701.87
Jul-13			248,971.00	$ 9,585,997.80	1,293.00	$ 62,076.75	$ 9,648,074.55
Aug-13			190,382.00	$ 7,416,745.98	379.00	$ 16,046.59	$ 7,432,792.57
Sep-13			291,939.00	$ 11,535,176.44	36,303.00	$ 1,789,352.32	$ 13,324,528.76
Oct-13			334,205.00	$ 13,114,329.26	80,620.00	$ 4,047,550.61	$ 17,161,879.87
Nov-13			457,360.00	$ 18,030,417.35	52,883.00	$ 1,874,343.43	$ 19,904,760.78
Dec-13			321,377.00	$ 12,630,329.08	41,592.00	$ 1,838,978.11	$ 14,469,307.19
Total-13			3,964,307.00	$ 155,504,696.35	266,664.00	$ 11,541,748.37	$ 167,046,444.72
Jan-14			507,892.00	$ 19,914,105.03	38,688.00	$ 1,728,478.18	$ 21,642,583.21
Feb-14			411,263.00	$ 16,252,377.79	27,021.00	$ 1,176,362.64	$ 17,428,740.43
Mar-14			428,808.00	$ 16,884,342.05	30,844.00	$ 1,235,263.17	$ 18,119,605.22
Apr-14			447,797.00	$ 17,496,382.62	34,533.00	$ 1,314,112.81	$ 18,810,495.43 *
May-14			346,548.00	$ 13,755,595.85	4,989.00	$ 213,648.70	$ 13,969,244.55
Jun-14			278,947.00	$ 11,122,900.96	12,304.00	$ 463,822.30	$ 11,586,723.26
Jul-14			276,189.00	$ 11,076,232.75	25,300.00	$ 904,356.54	$ 11,980,589.29
Aug-14			126,515.00	$ 5,120,318.25	4,402.00	$ 150,458.32	$ 5,270,776.57
Sep-14			300,800.00	$ 11,917,192.20	8,549.00	$ 331,616.85	$ 12,248,809.05
Oct-14			374,552.00	$ 14,959,305.81	34,474.00	$ 1,248,149.07	$ 16,207,454.88
Nov-14			482,136.00	$ 19,152,652.62	36,991.00	$ 1,417,771.91	$ 20,570,424.53
Dec-14			359,336.00	$ 14,274,263.33	10,171.00	$ 339,594.95	$ 14,613,858.28
Total-14			4,340,783.00	$ 171,925,669.26	268,266.00	$ 10,523,635.44	$ 182,449,304.70
Jan-15			430,437.00	$ 17,187,922.21	7,624.00	$ 331,500.15	$ 17,519,422.36
Feb-15			375,215.00	$ 14,988,985.89	12,640.00	$ 544,047.79	$ 15,533,033.68
Mar-15			419,845.00	$ 16,848,980.29	32,755.00	$ 1,211,708.37	$ 18,060,688.66
Apr-15			444,726.00	$ 17,770,333.68	13,183.00	$ 495,011.09	$ 18,265,344.77
May-15			399,998.00	$ 16,011,402.43	8,851.00	$ 357,751.08	$ 16,369,153.51
Jun-15				$ -		$ -	
Jul-15				$ -		$ -	
Aug-15				$ -		$ -	
Sep-15				$ -		$ -	
Oct-15				$ -		$ -	
Nov-15				$ -		$ -	
Dec-15				$ -		$ -	
Total-15			2,070,221.00	$ 82,807,624.50	75,053.00	$ 2,940,018.48	$ 85,747,642.98

* Due to a formula error, the 'Production Delivered Amount Xcel Energy Paid' in April 2014 was wrong. It was corrected in March 2015 FCC report. This change did not affect the curtailment payment amount and the fuel cost factor.

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 1 (ATC)
For January 2013 to June 2015

	Date Paid		Wind Production Delivered		Lost Production		
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-13			0.00	$ -	0.00	$ -	
Feb-13			0.00	$ -	0.00	$ -	
Mar-13			0.00	$ -	0.00	$ -	
Apr-13			188.19	$ 5,017.07	32.00	$ 853.20	$ 5,870.27
May-13			0.00	$ -	0.00	$ -	
Jun-13			0.00	$ -	0.00	$ -	
Jul-13			0.00	$ -	0.00	$ -	
Aug-13			0.00	$ -	0.00	$ -	
Sep-13			0.00	$ -	0.00	$ -	
Oct-13			0.00	$ -	0.00	$ -	
Nov-13			0.00	$ -	0.00	$ -	
Dec-13			0.00	$ -	0.00	$ -	
Total-13			188.19	$ 5,017.07	32.00	$ 853.20	$ 5,870.27
Jan-14			0.00	$ -	0.00	$ -	
Feb-14			0.00	$ -	0.00	$ -	
Mar-14			0.00	$ -	0.00	$ -	
Apr-14			0.00	$ -	0.00	$ -	
May-14			0.00	$ -	0.00	$ -	
Jun-14			0.00	$ -	0.00	$ -	
Jul-14			0.00	$ -	0.00	$ -	
Aug-14			0.00	$ -	0.00	$ -	
Sep-14			0.00	$ -	0.00	$ -	
Oct-14			0.00	$ -	0.00	$ -	
Nov-14			0.00	$ -	0.00	$ -	
Dec-14			0.00	$ -	0.00	$ -	
Total-14							
Jan-15			0.00	$ -	0.00	$ -	
Feb-15			0.00	$ -	0.00	$ -	
Mar-15			0.00	$ -	0.00	$ -	
Apr-15			0.00	$ -	0.00	$ -	
May-15			0.00	$ -	0.00	$ -	
Jun-15			0.00	$ -	0.00	$ -	
Jul-15			0.00	$ -	0.00	$ -	
Aug-15			0.00	$ -	0.00	$ -	
Sep-15			0.00	$ -	0.00	$ -	
Oct-15			0.00	$ -	0.00	$ -	
Nov-15			0.00	$ -	0.00	$ -	
Dec-15			0.00	$ -	0.00	$ -	
Total-15							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 2 (Low Load)
For January 2013 to June 2015

	Date Paid		Wind Production Delivered			Lost Production			Total	
Production Month	Delivered MWh	Lost MWh	MWh Delivered		Amount Xcel Energy Paid	Lost MWh		Amount Xcel Energy Paid		Xcel Energy Paid
Jan-13			0.00	$	-	0.00	$	-		
Feb-13			0.00	$	-	0.00	$	-		
Mar-13			0.00	$	-	0.00	$	-		
Apr-13			0.00	$	-	0.00	$	-		
May-13			0.00	$	-	0.00	$	-		
Jun-13			0.00	$	-	0.00	$	-		
Jul-13			0.00	$	-	0.00	$	-		
Aug-13			0.00	$	-	0.00	$	-		
Sep-13			76,548.00	$	2,901,817.33	838.00	$	60,482.56	$	2,962,299.89
Oct-13			0.00	$	-	0.00	$	-		
Nov-13			0.00	$	-	0.00	$	-		
Dec-13			0.00	$	-	0.00	$	-		
Total-13			76,548.00	$	2,901,817.33	838.00	$	60,482.56	$	2,962,299.89
Jan-14			0.00	$	-	0.00	$	-		
Feb-14			0.00	$	-	0.00	$	-		
Mar-14			0.00	$	-	0.00	$	-		
Apr-14			0.00	$	-	0.00	$	-		
May-14			0.00	$	-	0.00	$	-		
Jun-14			0.00	$	-	0.00	$	-		
Jul-14			0.00	$	-	0.00	$	-		
Aug-14			0.00	$	-	0.00	$	-		
Sep-14			0.00	$	-	0.00	$	-		
Oct-14			0.00	$	-	0.00	$	-		
Nov-14			0.00	$	-	0.00	$	-		
Dec-14			0.00	$	-	0.00	$	-		
Total-14										
Jan-15			0.00	$	-	0.00	$	-		
Feb-15			0.00	$	-	0.00	$	-		
Mar-15			0.00	$	-	0.00	$	-		
Apr-15			0.00	$	-	0.00	$	-		
May-15			0.00	$	-	0.00	$	-		
Jun-15			0.00	$	-	0.00	$	-		
Jul-15			0.00	$	-	0.00	$	-		
Aug-15			0.00	$	-	0.00	$	-		
Sep-15			0.00	$	-	0.00	$	-		
Oct-15			0.00	$	-	0.00	$	-		
Nov-15			0.00	$	-	0.00	$	-		
Dec-15			0.00	$	-	0.00	$	-		
Total-15										

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)
For January 2013 to June 2015

	Date Paid		Wind Production Delivered		Lost Production		
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-13			72,450.00	$ 2,082,854.97	3,485.00	$ 99,847.03	$ 2,182,702.00
Feb-13			124,791.00	$ 4,430,834.71	1,606.00	$ 59,496.20	$ 4,490,330.91
Mar-13			130,304.00	$ 3,740,576.42	5,915.00	$ 241,878.53	$ 3,982,454.95
Apr-13			214,542.81	$ 7,835,630.25	18,095.00	$ 779,711.60	$ 8,615,341.85
May-13			172,368.00	$ 6,676,131.24	14,849.00	$ 443,050.30	$ 7,119,181.54
Jun-13			121,792.00	$ 4,382,117.43	8,913.00	$ 270,229.36	$ 4,652,346.79
Jul-13			53,096.00	$ 1,642,558.63	980.00	$ 53,881.69	$ 1,696,440.32
Aug-13			37,477.00	$ 1,582,277.95	379.00	$ 16,046.59	$ 1,598,324.54
Sep-13			126,607.00	$ 4,851,723.76	35,465.00	$ 1,728,869.76	$ 6,580,593.52
Oct-13			226,538.00	$ 8,728,293.26	80,620.00	$ 4,047,550.61	$ 12,775,843.87
Nov-13			289,636.00	$ 11,075,512.84	52,883.00	$ 1,874,343.43	$ 12,949,856.27
Dec-13			207,681.00	$ 8,041,172.11	41,592.00	$ 1,838,978.11	$ 9,880,150.22
Total-13			1,777,282.81	$ 65,069,683.57	264,782.00	$ 11,453,883.21	$ 76,523,566.78
Jan-14			370,021.00	$ 14,326,083.51	38,688.00	$ 1,728,478.18	$ 16,054,561.69
Feb-14			306,417.00	$ 12,227,400.48	27,021.00	$ 1,176,362.64	$ 13,403,763.12
Mar-14			313,040.00	$ 12,270,317.48	30,805.00	$ 1,234,106.87	$ 13,504,424.35
Apr-14			257,997.00	$ 9,888,827.56	34,489.00	$ 1,312,837.86	$ 11,201,665.42
May-14			137,551.00	$ 5,259,198.52	4,989.00	$ 213,648.70	$ 5,472,847.22
Jun-14			196,092.00	$ 7,764,350.85	12,304.00	$ 463,822.30	$ 8,228,173.15
Jul-14			184,316.00	$ 7,332,372.22	25,300.00	$ 904,356.54	$ 8,236,728.76
Aug-14			50,900.00	$ 2,013,327.92	4,402.00	$ 150,458.32	$ 2,163,786.24
Sep-14			179,299.00	$ 6,870,476.62	8,549.00	$ 331,616.85	$ 7,202,093.47
Oct-14			274,412.00	$ 10,884,349.98	34,474.00	$ 1,248,149.07	$ 12,132,499.05
Nov-14			357,732.00	$ 14,199,215.53	36,991.00	$ 1,417,771.91	$ 15,616,987.44
Dec-14			166,565.00	$ 6,401,989.27	10,171.00	$ 339,594.95	$ 6,741,584.22
Total-14			2,794,342.00	$ 109,437,909.94	268,183.00	$ 10,521,204.19	$ 119,959,114.13
Jan-15			214,847.00	$ 8,505,929.28	7,624.00	$ 331,500.15	$ 8,837,429.43
Feb-15			202,707.00	$ 7,762,179.09	12,640.00	$ 544,047.79	$ 8,306,226.88
Mar-15			186,585.00	$ 7,230,936.47	32,755.00	$ 1,211,708.37	$ 8,442,644.84
Apr-15			187,399.00	$ 7,228,526.78	13,183.00	$ 495,011.09	$ 7,723,537.87
May-15			161,025.00	$ 6,178,315.06	8,851.00	$ 357,751.08	$ 6,536,066.14
Jun-15			0.00	$ -	0.00	$ -	
Jul-15			0.00	$ -	0.00	$ -	
Aug-15			0.00	$ -	0.00	$ -	
Sep-15			0.00	$ -	0.00	$ -	
Oct-15			0.00	$ -	0.00	$ -	
Nov-15			0.00	$ -	0.00	$ -	
Dec-15			0.00	$ -	0.00	$ -	
Total-15			952,563.00	$ 36,905,886.68	75,053.00	$ 2,940,018.48	$ 39,845,905.16

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 4 (Other-Paid)
For January 2013 to June 2015

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-13			0.00	$ -	0.00	$ -	
Feb-13			19,700.00	$ 516,531.75	699.00	$ 18,334.34	$ 534,866.09
Mar-13			0.00	$ -	0.00	$ -	
Apr-13			0.00	$ -	0.00	$ -	
May-13			0.00	$ -	0.00	$ -	
Jun-13			0.00	$ -	0.00	$ -	
Jul-13			27,170.00	$ 712,391.32	313.00	$ 8,195.06	$ 720,586.38
Aug-13			0.00	$ -	0.00	$ -	
Sep-13			0.00	$ -	0.00	$ -	
Oct-13			0.00	$ -	0.00	$ -	
Nov-13			0.00	$ -	0.00	$ -	
Dec-13			0.00	$ -	0.00	$ -	
Total-13			46,870.00	$ 1,228,923.07	1,012.00	$ 26,529.40	$ 1,255,452.47
Jan-14			0.00	$ -	0.00	$ -	
Feb-14			0.00	$ -	0.00	$ -	
Mar-14			0.00	$ -	39.00	$ 1,156.30	$ 1,156.30
Apr-14			0.00	$ -	44.00	$ 1,274.95	$ 1,274.95
May-14			0.00	$ -	0.00	$ -	
Jun-14			0.00	$ -	0.00	$ -	
Jul-14			0.00	$ -	0.00	$ -	
Aug-14			0.00	$ -	0.00	$ -	
Sep-14			0.00	$ -	0.00	$ -	
Oct-14			0.00	$ -	0.00	$ -	
Nov-14			0.00	$ -	0.00	$ -	
Dec-14			0.00	$ -	0.00	$ -	
Total-14					83.00	$ 2,431.25	$ 2,431.25
Jan-15			0.00	$ -	0.00	$ -	
Feb-15			0.00	$ -	0.00	$ -	
Mar-15			0.00	$ -	0.00	$ -	
Apr-15			0.00	$ -	0.00	$ -	
May-15			0.00	$ -	0.00	$ -	
Jun-15			0.00	$ -	0.00	$ -	
Jul-15			0.00	$ -	0.00	$ -	
Aug-15			0.00	$ -	0.00	$ -	
Sep-15			0.00	$ -	0.00	$ -	
Oct-15			0.00	$ -	0.00	$ -	
Nov-15			0.00	$ -	0.00	$ -	
Dec-15			0.00	$ -	0.00	$ -	
Total-15							

2014/2015 CURTAILMENT REPORT

I. INTRODUCTION

The Commission's April 4, 2006 Order regarding curtailment payments to wind developers (Docket No. E999/AA-04-1279) requires the Company to provide in future Annual Automatic Adjustment reports a projection of wind generation curtailment costs given existing and planned wind-generated energy purchases and transmission system needs. In compliance with the Commission's Order, this report provides a summary of the Company's experience regarding wind curtailment payments, an estimate of potential curtailment payments over the next five years, and the assumptions used to develop our forecast.

II. CURTAILMENT UPDATE

In past AAA Curtailment Reports, the Company has worked with the Department and made efforts to improve communications about the events and activity that causes wind generation curtailment. The Department's review and evaluation over the last several years has helped identify areas where our reports could be more descriptive of the reasons for wind curtailment and efforts made to minimize resulting costs.

Some of the information in this report will be familiar, because while an event may be reported during a particular AAA period, the recovery and restoration from these events often may continue across several AAA periods. Such is the case with work required as a result of a major ice storm that occurred in April 2013. Another example is the on-going work to help reduce transmission line galloping.

The Company expects that some level of wind curtailment from Power Purchase Agreement (PPA) facilities will occur during the foreseeable future. The reasons driving the curtailment have shifted from primarily local transmission constraints on NSP's transmission system in southwest Minnesota to regional transmission system congestion on the MISO system. The regional congestion, which results in negative Locational Marginal Pricing (LMP), was the largest driver of curtailment during this reporting period. Additionally, the nature of transmission congestion is accentuated by the large concentration and increased level of wind facility operations along southern Minnesota and all through Iowa.

Significant transmission improvements in southwestern Minnesota and the region such as the CapX2020 facilities are now in-service and will positively impact curtailment by reducing local congestion. However, the Company believes future curtailment in this area will still occur because of regional congestion and the resulting negative LMP in the Midcontinent Independent System Operator (MISO) energy market along with transmission outages required for construction, maintenance or repair activities. Congestion, and likely curtailment, will also occur as other companies take transmission facilities out of service to construct new transmission lines such as the MISO Multi-Value projects discussed later in this report.

To better manage regional congestion, MISO and the industry have implemented Dispatchable Intermittent Resources (DIR) which will provide better management of the wind resources. Under this system, a number of PPA wind facilities that are capable of operating as DIR have been registered with MISO as DIR. DIR facilities are given set point instructions every five minutes and rely on Automated Generation Control (AGC) technology, which automatically controls wind project output. DIR allows wind generators to be operated more like traditional generating facilities and, as a result, MISO is able to more quickly and accurately respond to system conditions. Manual curtailment of non-DIR PPA wind facilities also continues to be used to manage the wind resources when appropriate.

The existing PPA wind facilities associated with this report that are registered and that operate as DIR are listed in the following table.

Table 1
Dispatchable Intermittent Resources

Wind Project	MW
Fenton	200
Prairie Rose	200
MinnDakota	150
Mower County	100
Moraine II	50
Big Blue	36
Valley View	10
Community Wind South (Zephyr)	30

The federal Production Tax Credit (PTC) program, which provides tax subsidies to Wind Generating Plants has been extended again and now grants eligibility to projects that have begun construction prior to the end of 2016. In the past, the uncertainty of PTC expiration was closely connected with increases in wind curtailment, since wind projects were put into service to meet PTC eligibility requirements even though the necessary transmission upgrades were not completed. This will likely be the case going forward, as a significant number of projects are being placed in service prior to completion of all the necessary transmission upgrades. The Company is aware of 1,817 MW[1] of wind generation in Minnesota and Iowa that has gone into service over the last couple of years, or that is expected to go into service in 2015. In addition to this generation, the Company will add 750 MW of Company-owned and PPA wind facilities in 2015 and 2016 and MidAmerican Energy[2] has announced they will add 1,600 MW of wind generation in Iowa by the end of 2016. The required transmission upgrades for these wind projects will not all be in service by the time the projects begin producing energy. This will have a negative effect on LMP pricing in the MISO regional energy market that could potentially impact real-time wind generation on the NSPM System. This potential impact will lessen as the required transmission facilities and transmission system improvements are placed in service.

III. Transmission System Improvements

Since 1994, the Company's wind energy purchases have been the dominant factor in determining the need for transmission infrastructure improvements in southwestern Minnesota. To meet this need, the Company, often in cooperation with other utilities, has planned, engineered and constructed a number of projects designed to increase the transmission capacity in that area. The following table shows the southwest Minnesota projects that increased the available transmission outlet from 260 MW to the current limit of 1,950 MW.

[1] Projects that have recently gone into service or are scheduled to go into service soon include G573/G574/G575 (200 MW); G735/J091 (266 MW); G798 (150 MW); G870 (200 MW); G947 (99 MW); H007 (41 MW); H008 (36 MW); H009 (100 MW); H078 (119.6 MW); H096 (50 MW); J191/R65 (193.2 MW); J201 (20 MW); J289 (20 MW); J343 (150 MW); R49 (12 MW); G540/G548 (160 MW); (Total of 1816.8 MW).

[2] In May 2013, MidAmerican Energy Company announced plans to develop up to 1,050 MW of wind generation in Iowa by year-end 2015. In May 2015, MidAmerican Energy Company announced plans to develop an additional 552 MW of wind by the end of 2016.

Table 2
Southwest Minnesota Wind Limits

Transmission Project	Wind Outlet Increase	SW MN Wind Limit
425 MW Wind Transmission Expansion Project	October 2004[3]	425 MW
825 MW Wind Transmission Expansion Project	December 2007[4]	880 MW
Buffalo Ridge Incremental Generation Outlet (BRIGO)	December 2009[5]	1250 MW
CapX Brookings County - Southeast Twin Cities 345 kV Line	March 2015[6]	1950 MW

The Company is also participating in the development of the CapX2020 transmission projects (CapX) which include a number of projects that will positively impact transmission capacity and wind curtailment on the NSP system. These CapX transmission projects are listed in the following table.

Table 3
CapX Transmission Projects

Transmission Project	Transmission Owner	Actual/Planned In-Service Date
CapX Brookings County - Southeast Twin Cities 345 kV Line	Xcel Energy, Great River Energy	March 2015
CapX - Fargo North Dakota - Northwest Twin Cities 345 kV Line	Xcel Energy, Great River Energy	April 2015
CapX - Southeast Twin Cities - LaCrosse, Wisconsin 345 kV Line	Xcel Energy, SMMPA and non-MISO	Late 2016

[3] Completion of a majority of 425MW transmission facilities, and creation of the SW MN Wind operating guide, allowed the increase of the SW MN Wind limit to 425 MW in October 2004. All 425 MW transmission facilities were completed in December 2006.
[4] Completion of a majority of 825 MW transmission facilities, and update to the SW MN Wind operating guide, allowed the increase to SW MN Wind limit to 880 MW in December 2007. All 825 MW transmission facilities were completed in June 2008.
[5] With the completion of the BRIGO facilities, the southwest Minnesota operating guide no longer uses a total SW MN Wind Limit. The operating guide now includes limits for various facilities. The SW MN Wind limit referenced in this document is an estimate of the total limit.
[6] The CapX Brookings County to Twin Cities 345 kV line increased the transmission limit in southwest Minnesota to an estimated 1,950 MW. The transmission facilities were completed in March 2015.

The CapX transmission lines will increase the capacity of the bulk power transmission system and thus remove impediments to the delivery of power from wind farms around the region.

In addition to transmission projects developed by the Company, MISO has identified and approved a significant number of new transmission infrastructure projects including 17 Multi-Value Projects (MVPs) which are designed to accommodate the planned and expected generation expansion in the MISO footprint.[7] The completion of the MVP projects, particularly the ones listed in the following table, will have a positive impact on Company-owned and PPA wind facilities.

Table 4
MVP Projects

Transmission Project	Transmission Owner	Planned/Actual In-Service Date
Pleasant Prairie - Zion Energy Center 345 kV Line	American Transmission Company	December 2013
Big Stone South to Brookings 345 kV Line	Ottertail Power Company, Xcel Energy	End 2017
Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien Coutny - Kossuth County - Webster 345 kV Line	MidAmerica Energy, ITC Midwest	Mid 2018
North LaCrosse - North Madison	American Transmission Company, Xcel Energy*	End 2018
Winco to Hazleton 345 kV Line	MidAmerica Energy, ITC Midwest	End 2018
Ellendale to Big Stone South 345 kV Line	Ottertail Power Company, Montana Dakota Utilities	End 2019
North Madison - Cardinal - Spring Green - Dubuque area 345 kV Line	American Transmission Company, ITC Midwest	End 2020

* On April 23, 2015, the Wisconsin Commission granted ATC, NSP-Wisconsin, Dairyland Power Cooperative, SMMPA Wisconsin, LLC, and WPPI Energy a Certificate of Public Convenience and Necessity to construct this line.

[7] The MISO Board of Directors approved the new transmission projects, which included the CapX Brookings County – Southeast Twin Citites 345 kV line as a MVP, on December 13, 2012.

IV. Wind Generation, Curtailment and Curtailment Projections

Chart 1 shows Company-owned and PPA wind generation facilities throughout the NSP service territory on an incremental and cumulative basis, along with wind purchases for projects on-line or scheduled to come on-line through 2016.

CHART 1
NSP Wind Development
(1993 – 2016)

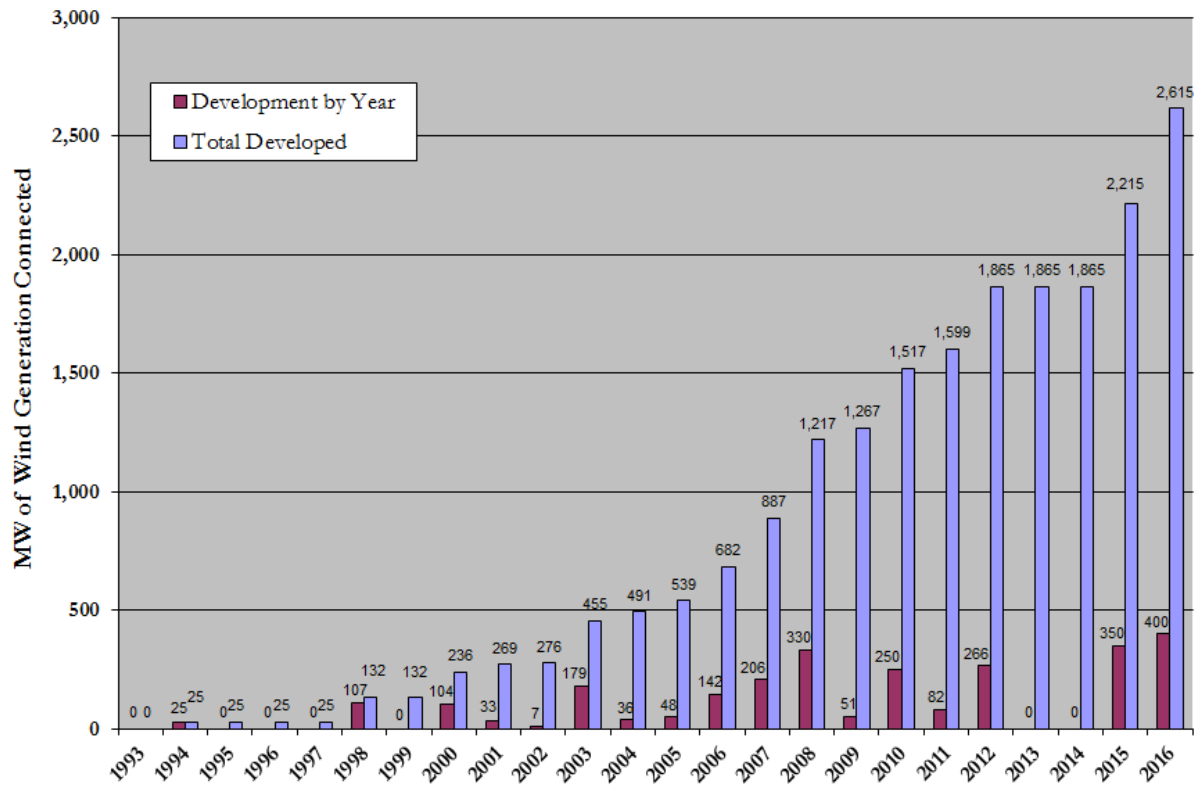

Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through May 2015[8]. Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation delivered.

Wind curtailment, as a tool to manage wind generation volumes when necessary, has had the positive benefit of facilitating a large amount of wind resources to be added to the system, which would not otherwise have been possible.

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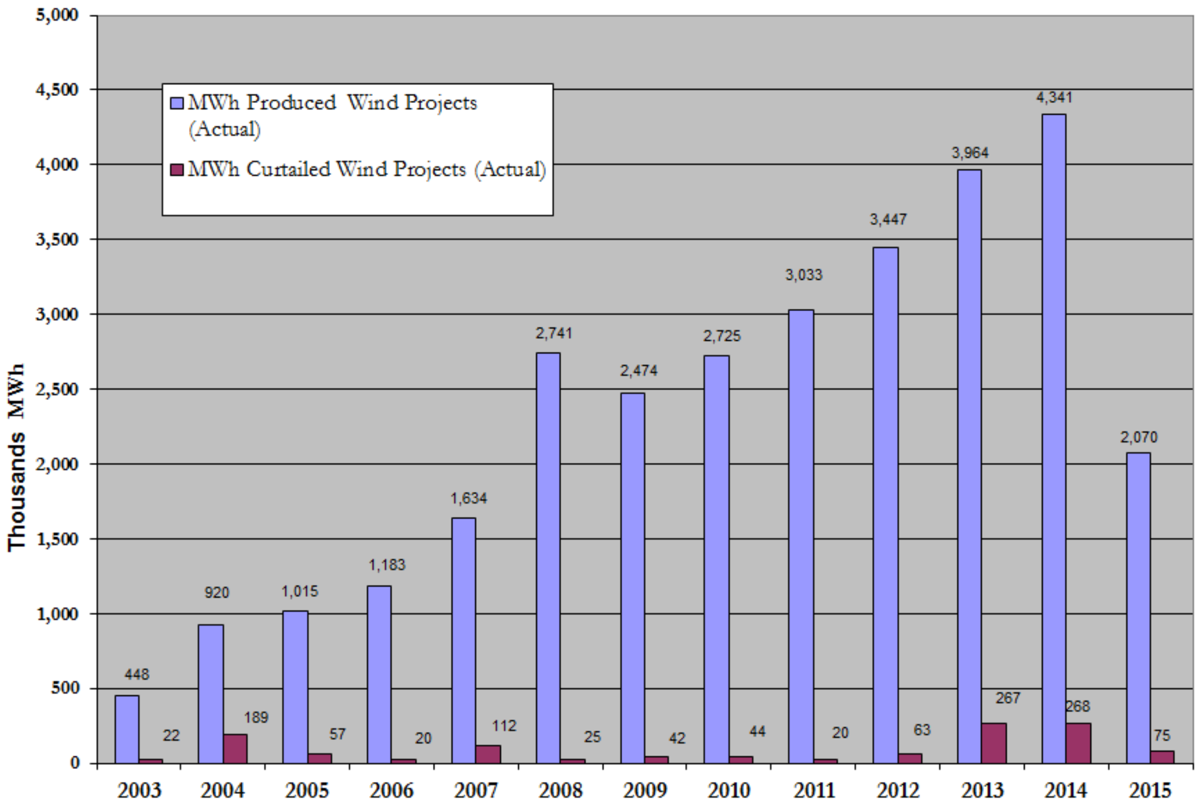
[8] AAA Part H, Section 5, Schedule 1.

Chart 2
NSP Wind Production & Curtailment (MWh)
(2015 Partial Year through May)



Curtailment during July 2014 to June 2015[9] was broken up into different categories to better explain the reasons for the curtailment and its cause. To support the analysis the Company identified hours during the 2014/2015 fiscal year where transmission-related outages impacted wind projects. During hours where transmission outages did not occur, or where transmission outages did not impact a specific wind farm, the hours were assigned as either manual curtailment or DIR – based on if a project was registered as a DIR. This hourly information was then compared to hourly curtailment data for each of the reporting wind farms and total MWh and curtailment costs were calculated. It should be noted that the hourly data was only assigned one category and did not overlap. The events resulting in curtailment payments for this reporting period fall into three categories:

1) Transmission Events; which include storm related repair/restoration on the Split Rock-Nobles-Lakefield Junction 345 kV lines along with transformer/

[9] The curtailment analysis in this section used Company data – not AAA Part H, Section 5, Schedule 1 data and included June of 2015.

substation outages at the Buffalo Ridge, Chanarambie, and Fenton substations (Transmission Events);

2) DIR Curtailments for negative LMP related reasons (DIR Curtailment Events); and
3) Manual curtailments for negative LMP related reasons (Manual Curtailment Events).

The MWh and curtailment costs determined during the curtailment analysis are compiled in Table 5 and Table 6 below. These results are further separated to show MWh and curtailment costs for projects that are still eligible for the PTC and those that are not. Note: the curtailment values in this section do not exactly match the curtailment values shown in AAA Part H, Section 5, Schedule 1. This data is based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices.

Table 5
2014/2015 Wind Curtailment MWh

Events	MWh		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	45,378	43,865	1,513
DIR Curtailment Events	43,049	38,867	4,182
Manual Curtailment Events	107,483	107,483	0
Total	195,910	190,215	5,695

Table 6
2014/2015 Wind Curtailment Costs

Events	Costs		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	$1,667,666	$1,544,591	$123,075
DIR Curtailment Events	$2,466,279	$2,140,447	$325,832
Manual Curtailment Events	$3,305,034	$3,305,034	$0
Total	$7,438,980	$6,990,073	$448,907

As can be seen in Tables 5 and 6, the majority of the curtailment was related to DIR and Manual Curtailment Events. These events can be attributed to regional congestion resulting in negative LMP. The remaining was related to transmission related outages – both planned and unplanned. The tables show that the bulk of the curtailment occurred at projects that are no longer eligible for the PTC.

It is important to note that of the $7,438,980 in total curtailment costs, the vast majority of these total costs, $7,219,378, are associated with the contractual energy price of the PPAs. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind farm.[10]

Transmission Curtailment Events

Wind curtailment costs totaling $1,667,666 were due to the transmission events described below.

The primary goal when planning construction and maintenance work that will impact wind generation output is to schedule these activities during times when wind is normally at its lowest levels – typically the summer months in the NSP service territory. While Xcel Energy attempts to plan outage work with this principle in mind, this is not always possible. For example, from September through the end of 2013, there were unavoidable transmission outages taken which resulted in significantly increased levels of curtailment than had been experienced in a number of years. Summer months are also high load months and transmission outages may not be possible due to load serving needs.

Split Rock – Nobles – Lakefield Junction 345 kV lines

A severe winter storm the week of April 8, 2013 produced significant, wide-spread icing from Sioux Falls all across southern Minnesota. Unprecedented damage occurred from the combination of ice weight and wind, causing a phenomenon known as 'galloping conductor,'[11] bringing down and/or weakening equipment, conductor and ground wires all along one of the key high-voltage transmission lines providing electric service support as well as wind generation outlet across the southern portion of Minnesota – the Split Rock-Nobles-Lakefield Junction 345 kV line. Significant (but temporary) repairs were performed as quickly as possible and the line was placed back into service on May 13, 2013, however, because of the extensive

[10] The PPA contract language can generally be described as "take or pay" in which NSP must pay for the wind energy that could be produced, regardless of whether it actually is produced or if it is curtailed.

[11] Conductor gallop is thought to be often caused by asymmetric conductor aerodynamics due to ice build up on one side of a wire, increasing the tendency of the normally round wire profile, to move and oscillate vertically, horizontally or in a rotational manner.

damage, more work was needed and a permanent repair plan was developed. This work continued through the 2014 and 2015 reporting period.

The Split Rock-Nobles-Lakefield 345 kV line provides a significant portion of the wind generation outlet from the southwestern Minnesota area and outages incurred along this line require reductions to the allowable amount of wind generation production that can be injected to the system at the Chanarambie, Fenton and Nobles County substations. Only wind generation connected to these specific substations can be used to manage this transmission event and include: Lake Benton II, Chanarambie Power Partners, Ridgewind, Moraine I, Moraine II, Fenton, and Zephyr.

In addition to developing plans for damage repair, the Company also initiated an effort to proactively identify solutions to the galloping conductor issue and evaluate alternate conductor options for consideration in certain parts of the route where the geographic orientation may combine unfavorably with prevailing winter winds and icing conditions. Additional outages were required in 2014 and 2015 and include activities such as installing various anti-galloping devices, phase spacers and reconductoring especially sensitive areas along the line route. In a preventative effort, the Company has been working in collaboration with the Electric Power Research Institute (EPRI) on ways to mitigate galloping (involving installation of new technology on the 345 kV line in the Split Rock-Lakefield Junction area) and to evaluate various devices that mitigate galloping. Some mitigation designs create sufficient spacing between conductor phases to prevent flashovers, and ice/snow prevention and removal applications. Other more recent techniques include technologies to increase conductor tension or stiffness; weight pendulums and air dampers to limit motion; and different conductor configurations to counter wind effects. EPRI advised on placement of line monitoring stations that serve as data collections points to monitor device effectiveness in minimizing or preventing conductor gallop. Additionally, motion sensors were installed on select conductor spans to analyze movement and collect data. Since the exact location and date of the next galloping event cannot be predicted, EPRI will aid the Xcel Energy team in result evaluation over a period of time. Collected data will aid in choosing anti-galloping devices to use in the region and assist in determining areas where geographic orientation of transmission lines and prevailing winds would combine unfavorably, and therefore should be designed to special galloping requirements.

Buffalo Ridge, Chanarambie, Fenton and Brookings County Substation Equipment Outages
The Company experienced a number of planned and unplanned outages of transformers and breakers at the Buffalo Ridge, Chanarambie, Yankee, Fenton and Brookings County substations that contributed to curtailment during this period.

Transformer outages were the primary contributors to the curtailment. Animal contact with energized components caused damage to Fenton and Chanarambie transformers that required outages to make repairs. Buffalo Ridge transformers were taken out of service for scheduled preventative maintenance. A Brookings County transformer was taken out of service to allow installation of new reactive support equipment. In addition, a Buffalo Ridge breaker and a Chanarambie transformer were taken out of service to repair failed equipment. Only wind generation connected to each specific substation could be used to manage these transmission events. Buffalo Ridge outages could impact Lake Benton I, Lake Benton II and Wind Power Partners 1993. Chanarambie outages could impact Lake Benton II, Chanarambie Power Partners, Ridgewind, Moraine I, and Moraine II. Fenton outages could impact Fenton. Brookings County outages could impact MinnDakota.

<u>DIR Curtailment Events</u>
Wind curtailment costs totaling $2,466,279 were due to the MISO directed DIR control as described below.

DIR related curtailment was due to negative LMP prices associated with congestion throughout the Minnesota and Iowa region due to regional transmission outages, as well as the higher levels of wind generation present where all required transmission improvements have not been completed.

DIR wind farms are managed by MISO through automatic control, and these facilities are required to comply with the MISO cost signals. Failure to comply would expose the Company to Revenue Sufficiency Guarantee charges.

<u>Manual Curtailment Events</u>
Wind curtailment costs totaling $3,305,034 were due to the Manual Curtailment Events as described below.

Unlike DIR wind farms where MISO controls the wind farms output, non-DIR wind facilities require recognition of trends and action by an NSP system dispatcher. The economic decision to curtail a wind farm is specifically affected by whether or not a wind farm qualifies for federal PTCs. As a result, the comparison of the Contractual price, including PTC, for the wind farm with the relevant LMP determines if it is economic to curtail the wind farm or accept the generation.

Concerning the prudency of non-transmission limited, manual economic, congestion and negative LMP related curtailments, NSP performed an analysis of the economic impact of this curtailment type and determined that the curtailments produced customer economic value by reducing costs by nearly $500,000 as shown in Table 7.

Table 7
Manual Actions Related to Economics

Connection Node	MWh	Curtailment Benefit $	Average Benefit $/MWh	PTC or No PTC
Chanarambie	25,365.62	$108,953.15	$ 4.30	No PTC
Lake Benton I	34,112.53	$156,255.02	$ 4.58	No PTC
Lake Benton II	25,476.11	$61,989.13	$ 2.43	No PTC
Moraine	9,067.00	$72,961.13	$ 8.05	No PTC
Ridgewind Power Partners	6,544.06	$39,522.33	$ 6.04	No PTC
Wind Power Partners 1993	6,918.04	$59,795.83	$ 8.64	No PTC
Total	107,483.37	$499,476.60	$ 4.65	

To perform this analysis the Company started with estimated hourly averaged curtailment volumes[12] and hourly averaged LMP values for all non-DIR wind farms. The Company then manually subtracted the curtailment volumes for hours that were specifically identified as Transmission Curtailment Events. The resulting hourly curtailment data represents all manual curtailments that were made for economic reasons and not due to a transmission limitation. The hourly curtailment volume for each wind farm was then multiplied by the corresponding hourly LMP for that wind farm to determine the hourly settlement impact of the curtailed wind generation.
It is important to note that the bulk of these total costs are associated with the contractual energy price of the PPA. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind farm. The only economically relevant factor in the decision whether or not to curtail a wind farm is whether the real-time LMP is above or below the dispatch price for the wind farm.

[12] NSP used hourly averaged curtailment data based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices. As a result, the data does not perfectly match the curtailment volumes on the customer invoices, which is the basis for the volumes used in the Company's response to Information Request No. DOC-008, Attachment B in Docket No. E002/AA-14-579.

III. Wind Production and Curtailment Payments

Chart 3 shows the corresponding production and curtailment costs through May, 2015[13]. As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

Chart 3
NSP Wind Production & Curtailment Payments
(2015 Partial Year through May)

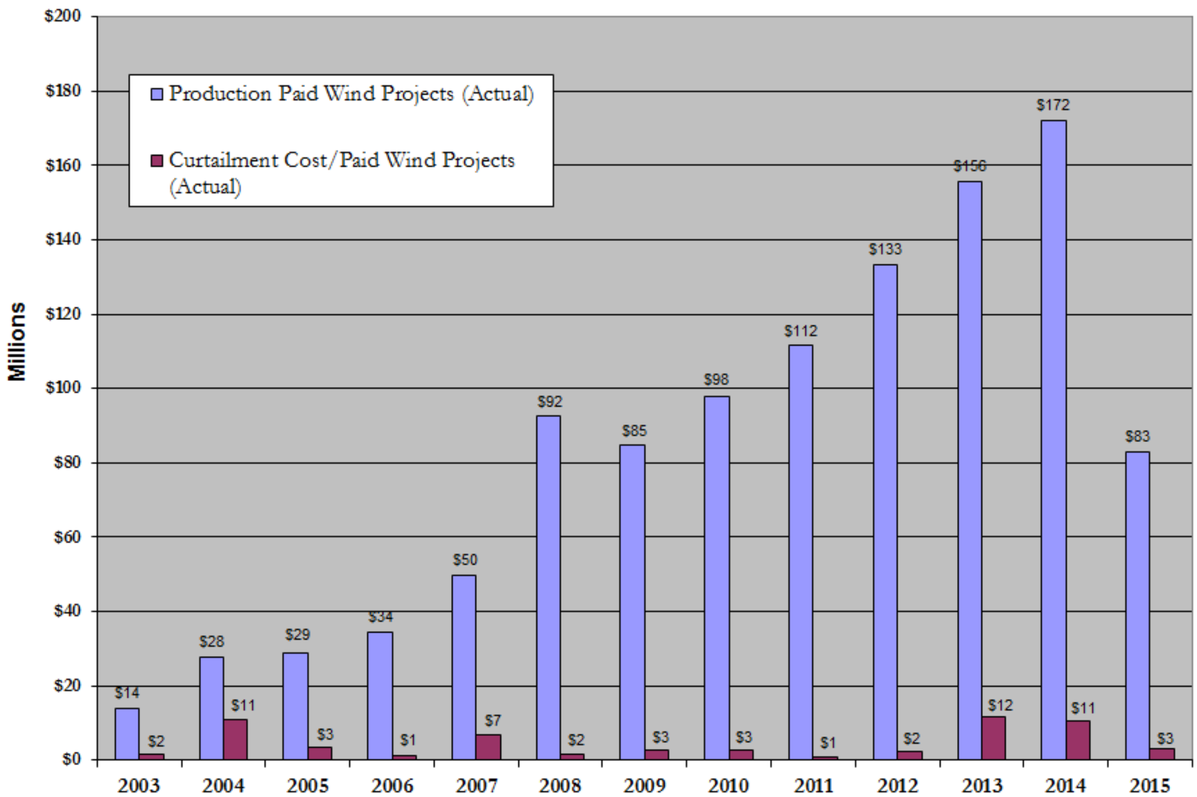


Chart 4 shows the Company's historical wind curtailment costs along with the five-year estimate of future costs. Over the next five years, we anticipate that the wind generation curtailment and associated payments to vendors will result from planned and unplanned transmission outages and negative LMP prices.

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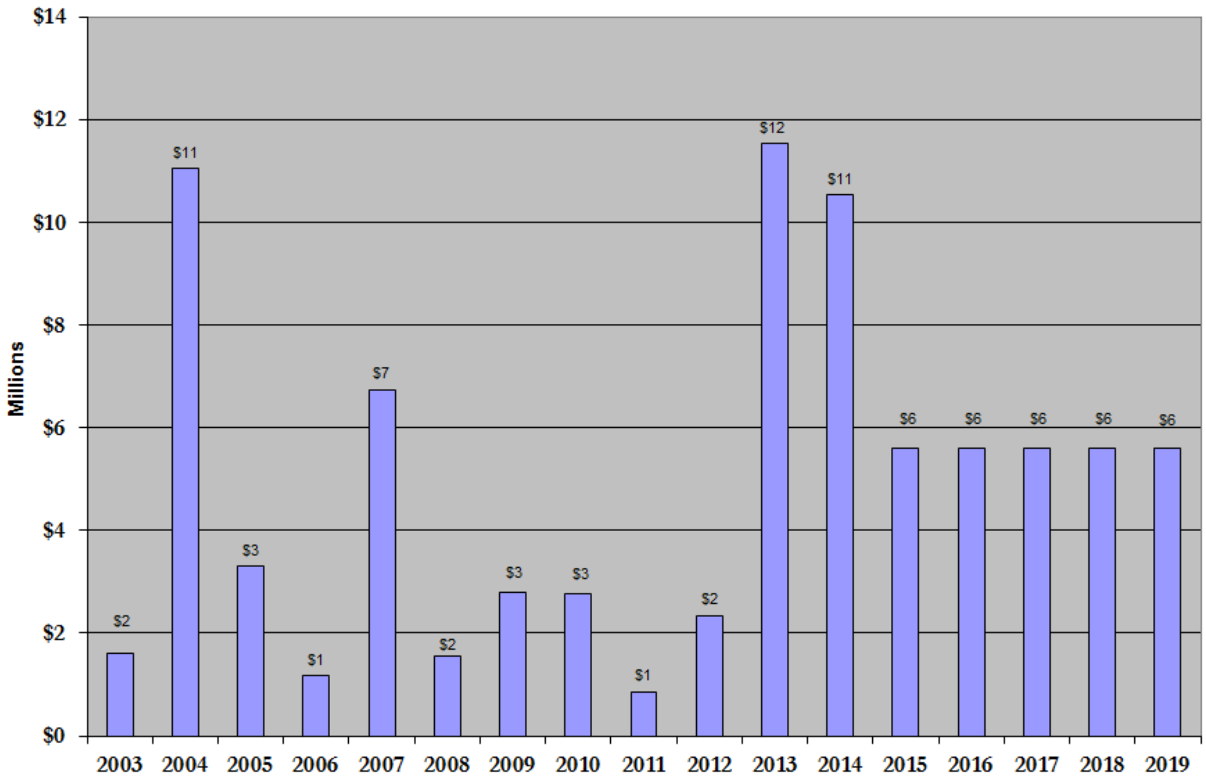
[13] AAA Part H, Section 5, Schedule 1

Chart 4
NSP Wind Curtailment Payments
(2003 –2014 Actual, 2015 – 2019 Projected)



As was the case in the 2013/2014 AAA Report, we are projecting a value for future curtailment differently than in curtailment reports prior to 2013. In those earlier reports, curtailment associated with maintaining transmission reliability during system intact conditions was the primary focus. However, we believe given the current MISO market and the amount of wind generation installed in southern Minnesota and Iowa, it would be reasonable to expect there will be ongoing wind curtailment due to negative LMP events, congestion and transmission outages.

The Company believes using recent actual experience as the basis for estimating future wind curtailment to be a reasonable methodology and has used the average of the last 5 years of historical curtailment data to project the level of future curtailment. The basis for moving to this type of curtailment estimate was that by 2008 and 2009, the transmission infrastructure caught up with wind generation development and curtailment began to be more consistent. With completion of all of the CapX2020 lines, the next needed increase in the bulk transmission system will be in place. Using the last five years to predict curtailment will help capture and reflect ongoing trends with wind and transmission development, as well as the outages necessary for maintenance, repair and construction activity.

Future wind generation additions and completion of the CapX and other MVP transmission projects will likely impact the amount of future curtailment experienced. It is reasonable to expect curtailment levels will be reduced once the new transmission lines are in service. However, there is no certainty as to when, and if, the numerous wind generation projects currently in the development queue, will actually come to fruition. As such, the Company did not try to predict the specific impact that future wind generation or completion of the CapX and MVP transmission projects would have on curtailment.

VI. CONCLUSION

The Company anticipates that wind generation curtailment and associated payment to vendors will occur over the next five years as the result of transmission capacity reductions caused by planned and unplanned transmission outages and negative LMP in the MISO energy market. System conditions and wind project development are very dynamic and actual curtailment may vary from that projected in this report. We will continue to refine and gather information for use in future updates to be submitted with subsequent AAA reports.