Impact of Energy Imbalance Tariff on Wind Energy

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Abstract

The amount of electric energy used by customers is usually not controlled. Utility system operators must schedule generators to provide the electricity needed by customers. Although the amount of energy delivered in an hour is generally controllable with certain precision for conventional generators, the energy actually generated is not always exactly the same as the energy scheduled in an hour. The difference between energy scheduled and actually used or generated is the imbalance energy. The energy imbalance service tariff is designed to discipline the power market by promoting better scheduling and discouraging unfavorable generator operating practices. Because of the variable nature of wind, the difference between predicted and actual generated wind energy is inevitable despite progress made in wind forecasting. It is obvious that an energy imbalance tariff that is designed to penalize generators that intentionally deviate from schedule will have a negative impact on wind energy.

In early 2007 the Federal Energy Regulatory Commission (FERC) issued Order 890, which adopted a tiered approach to energy and generation imbalance. This paper summarizes the results of a study that uses actual wind power data collected by NREL and actual hourly energy prices of the Midwest Independent Transmission System Operator to analyze the impact of FERC energy imbalance tariff on wind power. Sensitivities of the results to various components of the imbalance tariff, such as different deviation band widths and penalty stipulations, were simulated, and the effects of improving wind forecasting accuracy were also tested.

The study shows the design of the penalty for energy deviation has a roughly 2% impact on wind plant revenue. Other factors studied, such as improving wind forecasting accuracy, can somewhat reduce but not eliminate this impact.

Introduction

Energy imbalance service is one of the ancillary services specified in the Open Access Transmission Tariff by FERC Order No. 888. The amount of energy consumed by load in a given time frame is variable and usually not controllable. System operators have to schedule generators to serve the load. While the amount of energy delivered in a given time is generally controllable with certain precision for conventional generators, the energy actually generated is not always exactly the same as the energy scheduled during the same time. The difference between energy scheduled and actually used or generated in an hour is the imbalanced energy that needs to be provided by system operators. The energy imbalance service tariff is designed to promote system reliability by encouraging better scheduling and by discouraging unfavorable operating practices, such as intentional deviation from a schedule. The energy imbalance service is applicable to both load and generation. However in this report this term is used exclusively for generation imbalance.

In early 2007 FERC issued Order 890[1], which adopted a tiered approach to energy imbalance. Under the FERC order the hourly energy imbalances (either over or under schedule) of less than or equal to 1.5% of

[1] FERC Docket Nos. RM05-17-000 and RM05-25-000, Order 890.

the scheduled energy (or 2 MW, whichever is larger) will be netted out on a monthly basis and settled at actual incremental or decremental cost. Imbalances outside this band will be charged 110% of system incremental cost for the amount of energy under-delivered (the actual energy delivered during the hour is less than that scheduled) and will only be paid 90% of the system decremental cost for the amount over-delivered (the actual energy delivered during the hour is more than that scheduled). This is equivalent to a 10% penalty for energy imbalance that is outside the 1.5% deviation band. The deviation band offers operating flexibility and penalties discourage unfavorable generator operating practices.[2]

Wind energy is variable in nature. Despite the significant progress made in wind forecasting, some difference between predicted and actually generated hourly wind energy is inevitable. It is obvious that these deliberately imposed energy imbalance tariffs will have a negative impact on wind. This study uses actual wind power data and real-time prices to examine such impacts on wind plant's revenue.

Data and Simulation

Actual hourly average wind power data time series of a wind plant (nameplate capacity 103 MW) located in the Midwest region are used in this analysis. The actual hourly outputs are derived from the 1-second data series NREL collected at the wind plant. To produce the hourly time series that represents the forecasted (scheduled) hourly output which is finalized 80 minutes before the start of the hour (–80 minutes), the average wind power generated during the previous 60 minutes (i.e., the period from –80 minutes to –140 minutes) was calculated. This represents a simple wind energy forecasting strategy based on wind persistency. The imbalance is the difference between the actual wind power produced and the scheduled power during the hour and is further separated into two categories (within the 1.5% band or without) in this analysis. The simulation is carried out for 2003, 2004, and 2005, and the imbalance was tallied hourly, monthly and yearly.

The hourly cost data are based on Midwest Independent Transmission System Operator (MISO) day ahead hourly prices from April 1, 2005 to March 31, 2006 (total 12 months). The overall average hourly price for this data set is $44.38/MWh. The highest hourly price is $362.96/MWh and the lowest hourly price is -$3.61/MWh. There are actually 52 hours of negative prices in the yearly data set (about 0.6% of the time). Not surprisingly, the high hourly prices tend to occur around late afternoon (4:00 p.m. to 5:00 p.m.), early evening (between 7:0 p.m. and 10:00 p.m.) and morning hours (8:00 a.m. and 9:00 a.m.) while the low hourly prices tend to occur around early morning hours (from midnight to 7:00 a.m.). Figure 1 shows the hourly prices of two 7-day periods. The period from May 24 to May 30 had the lowest average hourly price at $23.61/MWh while the period from December 3 to December 9 had the highest average hourly price at $212.46/MWh. Despite the huge differences in hourly prices during these periods, the distinctive pattern of daily price variation is still clear. Although the hourly price data used in the analysis are not the actual system prices used for settlement during the three test years, it is a reasonable approximation. The results are still useful in providing an insight of the impact on wind energy.

[2] The FERC order actually contains three deviation bands for energy imbalances: less than 1.5%, between 1.5% and 7.5%, and above 7.5%. The 90%/110% rule applies only to the second band (between 1.5% and 7.5%). Higher penalties are applied to the imbalances greater than 7.5% of the scheduled energy. However, wind energy is exempted from the third band.

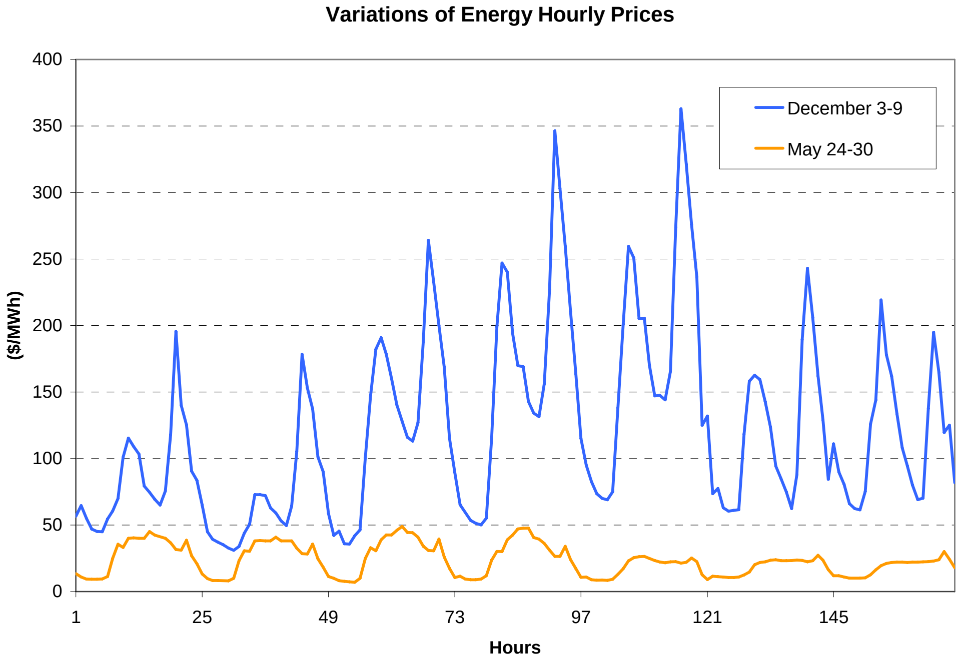

Figure 1. Examples of hourly energy prices

In this analysis, it is assumed that a wind plant operator will receive a base payment equal to scheduled energy multiplied by the hourly price. The hourly energy imbalance within the deviation band (both over- and under-delivery) will be netted out at the end of the month and settled at monthly average hourly prices. It can be either a payment or a charge to the wind plant operators depending on the sign of the netted energy (positive for over-delivery and negative for under-delivery). When the hourly imbalance is outside the 1.5% band, the wind plant operators will receive an additional payment equal to the amount of the imbalance over 1.5% multiplied by 90% of the energy price for the hour[3] for over-delivery (i.e., the actual generation is more than the scheduled amount). For under-delivery (the actual generation is less than the scheduled amount for the hour), the wind plant operators will be charged an amount equal to the imbalance outside the deviation band multiplied by 110% of the energy price for the hour.[4]

To establish a baseline revenue for the year so we can compare the effects of different deviation band widths and forecasting accuracies, a theoretical maximum revenue for each test year is calculated by assuming the wind energy will be paid at the hourly price for actual energy generated. The resulting revenues can be interpreted as the revenue for the wind plant operators with perfect hourly forecasting (the scheduled wind power is always equal to the actual wind generation every hour) or no energy imbalance penalty. This number is thus independent of the deviation band width and 90%/110% rule (or any other similar rules). Any revenue deviation from this number reflects a deliberately imposed penalty on wind power because of an inadvertent forecasting inaccuracy. Table 1 lists the maximum revenues and average per kWh prices along with the actual annual wind generation and total scheduled energy (simulated) for the three test years.

Table 1 shows that the simple persistence method tends to over-forecast the wind power. For the 3 test years, the scheduled wind energy is higher than the actual wind generation, ranging from 0.5% to 1.4% higher. The table also shows that even with the identical hourly prices, natural variations of wind energy

[3] This should be the system hourly incremental price. In this analysis the hourly energy prices are used for both the incremental and decremental prices.
[4] Id.

production from year to year will result in different annual average kWh prices. The average prices calculated from the actual wind generation are also lower than the average hourly price of the hourly price data set itself. With the maximum revenue based on actual production, the average prices for the 3 test years range from 4.291¢/kWh to 4.436¢/kWh —all of which are lower than the 4.438¢/kWh price calculated from data set itself. It appears that the distribution of actual wind energy generation does not match the distribution of hourly prices. The wind at this location tends to produce more electricity during low price periods than during high price periods.

Table 1. Maximum Revenue Case

	2003	2004	2005
Wind Generation (MWh)			
Actual	313,771	244,655	283,378
Scheduled (from simulation)	313,803	244,667	283,418
% Increase	1.0%	0.5%	1.4%
Max Revenue ($000), Actual	**13,918**	**10,548**	**12,161**
Average Unit Price (¢/kWh)	**4.436**	**4.312**	**4.291**
Max Revenue ($000), Scheduled	13,855	10,530	12,097
Average Unit Price (¢/kWh)	4.415	4.304	4.268
% Change over Actual	(0.47%)	(0.19%)	(0.54%)

The table also shows that despite the fact that the total scheduled energy (based on the persistence method) for the year is slightly higher than the actual production of the year, the maximum revenues based on the total scheduled energy (i.e., wind be paid for the scheduled energy at the hourly price) are less than those based on actual production. For example using 2003 data, total actual hourly production of 313,771 MWh will generate a revenue of $13,917,627 while the total scheduled hourly energy of 313,803 MWh will only generate $13,855,497.

More energy (scheduled) resulting in less revenue highlights the linkage between the hours of high price and the hours when wind is producing electricity, but more factors are in play here. A brief discussion is provided below.

Actual revenues are consistently higher than forecasted in this case because of the nature of the persistence forecast, the typical daily wind pattern in this region, and the nature of power price fluctuations. Figure 2 provides a stylized example to help explain the phenomena. The example is stylized to emphasize the differences. Power price (dark blue) follows a typical daily load pattern with an afternoon peak. Wind output (green) shows a similar pattern but typically peaks about 5 hours later than load and price. As is not uncommon, the wind pattern does not perfectly match the daily load or price pattern and in fact tends to provide more energy during off-peak hours. In this case, the wind pattern lags the daily price pattern by a few hours. Because the persistence forecast (dotted blue) lags the actual wind output, the forecasted wind production is even farther off-peak than the actual wind production; the persistence forecast understates the value of wind generation. The wind forecast error energy (dashed red) is symmetric with equal over- and under-production but the value of the error energy (purple) is not symmetric. The net area under the purple curve is positive. Actual wind overproduction tends to happen at a time when power prices are high (afternoon) so the wind plant gets paid 90% of a high price for the forecast error energy. Wind underproduction tends to happen in the early morning when energy is cheap so even though the wind generator has to pay 110% of the market price for the forecast error this is at a relatively low price time.

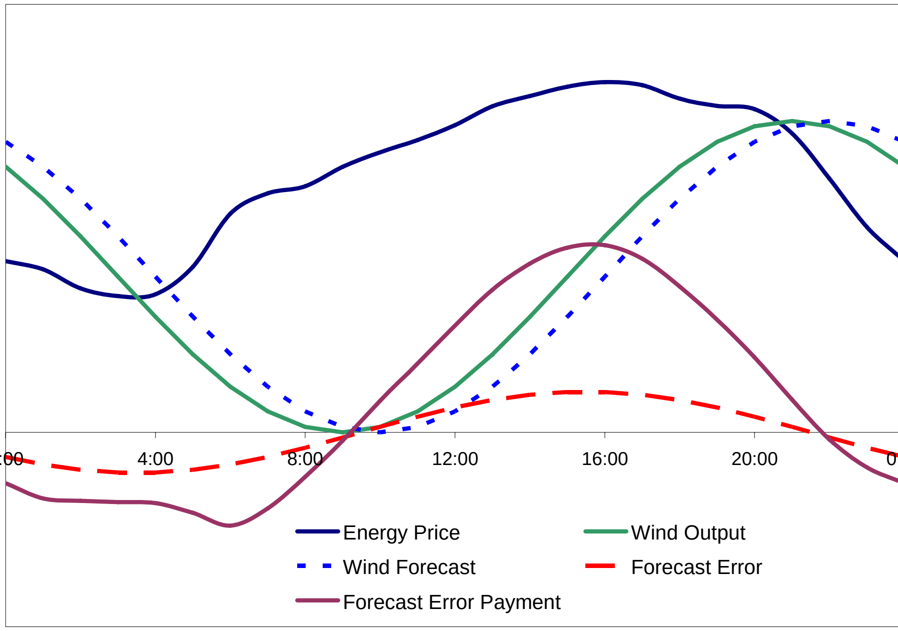

Figure 2. Actual payments exceed forecasted because of the wind pattern and the nature of persistence forecasts.

This extra revenue may not be considered a bonus for the wind generator. It is the forecast error that results in the Max Revenue Scheduled being below the Max Revenue Actual. In fact, an improved forecast would increase both numbers because it would reduce the 10% out-of-band penalty as well as reduce the extent to which the forecast error overstates the off-peak nature of the wind production. Note that if the wind pattern had high production early in the day, before the load and price picked up, the persistence forecast would tend to move the forecasted production into the peak and would overstate the value of the wind. Actual revenue would be below forecasted.

After establishing the baseline, test cases were run with FERC energy imbalance rules and with variations of rules such as different deviation band widths and improved forecasting accuracy. To simulate the improvement in forecasting (scheduling), the hourly imbalance from the persistence method is artificially reduced by a fixed ratio. For example, to simulate a 15% improvement over the simple persistence method, the hourly imbalance from the persistence method is multiplied by a factor of 0.85 and the scheduled energy for the hour is adjusted to reflect the reduced imbalance. The industry experience has shown that actual forecasting accuracy with sophisticated numerical models and real time weather data and wind plant outputs is 5% to 25% better than the persistence method. Forecasting improvements of 15% and 25% are simulated in this analysis.

Summary of Simulation Results

1. The FERC Rule (Base Case)

With the ±1.5% deviation band and 90%/110% rule for imbalance energy outside the band, annual wind plant revenues will be reduced. Table 2 lists the simulation results. On average the wind plant revenues will be decreased by about 1.9% compared to the maximum revenues with no deviation band (for the 3 test years of 2003, 2004, and 2005, the percentages range from 1.71% to 2.11%). Table 3 shows the monthly average hourly prices, monthly netted energy, and costs (payment or charge) associated with the in-band netting for the 3 test years.

Table 2. Base Case (±1.5% Deviation Band and with 90%/110% Rule)

±1.5% Deviation Band	**2003**	**2004**	**2005**
Imbalance (MWh)			
Total Over-Delivery	32,711	32,592	32,672
Inside Band	7,053	6,790	6,981
Total Under-Delivery	(32,743)	(32,605)	(32,712)
Inside Band	(7,074)	(6,936)	(7,106)
Revenue ($000)			
Base Payment	13,855	10,530	12,098
Outside Band Payment @90%	1,047	1,004	1,026
Outside Band Charge @110%	(1,222)	(1,203)	(1,183)
Sum of Inside Band Monthly netting	(0)*	(6)	(6)
Net (Monthly Netting)	13,680	10,325	11,935
Unit Price (¢/kWh)			
Net (Monthly Netting)	4.360	4.220	4.212
% Change over Max Revenue Case	**(1.71%)**	**(2.11%)**	**(1.86%)**

*small negative amount less than $1,000.00 (see Table 2)

Table 3. Summary of Monthly Imbalance within ±1.5% Deviation Band

		2003		**2004**		**2005**	
	Average Hourly Price ($/MWh)	Monthly Net Imbalance (MWh)	Payment or (Charge) ($)	Monthly Net Imbalance (MWh)	Payment or (Charge) ($)	Monthly Net Imbalance (MWh)	Payment or (Charge) ($)
Jan	37.98	7	272	(25)	(942)	(43)	(1,614)
Feb	40.52	(12)	(506)	40	1,602	10	410
Mar	34.41	(51)	(1,769)	(91)	(3,116)	18	612
Apr	38.92	74	2,886	1	36	(24)	(915)
May	28.81	(22)	(622)	(4)	(127)	(43)	(1,225)
Jun	44.32	16	696	(37)	(1,639)	(25)	(1,128)
Jul	55.88	(2)	(121)	52	2,882	20	1,126
Aug	46.82	(1)	(55)	23	1,059	4	208
Sep	42.87	9	371	23	992	38	1,614
Oct	45.33	(32)	(1,442)	(61)	(2,787)	(10)	(449)
Nov	42.92	(20)	(843)	(38)	(1,622)	(33)	(1,436)
Dec	73.14	14	1,002	(28)	(2,063)	(38)	(2,765)
Yearly	44.38	(21)	(132)	(146)	(5,725)	(125)	(5,562)

2. Sensitivity to Deviation Bandwidth

To see how much change to the potential wind plant revenue would occur under a wider deviation band, the same simulation was performed using a ±10% deviation band. As expected the net revenue for the wind plant operators would increase, but only slightly (about 0.29% higher). However, they are still less than the base cases—ranging from 1.42% to 1.85% less. Table 4 lists the results. Both the charge for under-delivery and additional payment for over-delivery decrease as expected. The imbalance energy within the deviation band increases significantly as do the annual net amounts that are settled at the end of each month. In this case, the monthly net imbalance energy within the deviation band is always negative (see Table 5 for the monthly netted energy and net charges).

Table 4. 10% Deviation Band with 90%/110% Rule

±10% Deviation Band	**2003**	**2004**	**2005**
Imbalance (MWh)			
Total Over-Delivery	32,711	32,592	32,672

Inside Band	10,953	9,496	10,532
Total Under-Delivery	(32,743)	(32,605)	(32,712)
Inside Band	(13,249)	(11,858)	(12,914)
Revenue ($000)			
Base Payment	13,855	10,530	12,098
Outside Band Payment @90%	886	898	891
Outside Band Charge @110%	(922)	(972)	(912)
Sum of Inside Band Monthly netting	(99)	(103)	(103)
Net (Monthly Netting)	13,720	10,353	11,974
Unit Price (¢/kWh)			
Net (Monthly Netting)	4.373	4.232	4.225
% Change over Base Case	**(1.42%)**	**(1.85%)**	**(1.54%)**
Change over the ±1.5% Case	0.29%	0.27%	0.32%

Table 5. Summary of Monthly Imbalance with ±10% Deviation Band

		2003		**2004**		**2005**	
	Average Hourly Price ($/MWh)	Monthly Net Imbalance (MWh)	Payment or (Charge) ($)	Monthly Net Imbalance (MWh)	Payment or (Charge) ($)	Monthly Net Imbalance (MWh)	Payment or (Charge) ($)
Jan	37.98	(209)	(7,944)	(260)	(9,879)	(185)	(7,029)
Feb	40.52	(244)	(9,900)	(113)	(4,506)	(154)	(6,222)
Mar	34.41	(277)	(9,547)	(314)	(10,811)	(157)	(5,402)
Apr	38.92	(50)	(1,959)	(144)	(5,606)	(303)	(11,780)
May	28.81	(238)	(6,857)	(183)	(5,270)	(339)	(9,763)
Jun	44.32	(106)	(4,694)	(221)	(9,808)	(199)	(8,800)
Jul	55.88	(163)	(9,125)	(60)	(3,371)	(92)	(5,130)
Aug	46.82	(104)	(4,886)	(148)	(6,918)	(112)	(5,257)
Sep	42.87	(232)	(9,937)	(167)	(7,178)	(135)	(5,785)
Oct	45.33	(206)	(9,361)	(283)	(12,832)	(156)	(7,080)
Nov	42.92	(295)	(12,672)	(257)	(11,021)	(308)	(13,207)
Dec	73.14	(169)	(12,389)	(211)	(15,452)	(243)	(17,754)
Yearly	44.38	(2,296)	(99,271)	(2,362)	(102,652)	(2,381)	(103,209)

When the deviation band is further increased to ±20%, the revenues continue trending upward (see Table 6)—about 0.67% more than that in the ±1.5% case. This exercise confirms the idea that wider deviation band is better than narrower one, but the improvement is only marginal.

Table 6. 20% Deviation Band with 90%/110% Rule

±20% Deviation Band	**2003**	**2004**	**2005**
Imbalance (MWh)			
Total Over-Delivery	32,711	32,592	32,672
Inside Band	15,856	13,787	15,149
Total Under-Delivery	(32,743)	(32,605)	(32,712)
Inside Band	(20,350)	(18,690)	(20,023)
Revenue ($000)			
Base Payment	13,855	10,530	12,098
Outside Band Payment @90%	686	730	713
Outside Band Charge @110%	(587)	(643)	(581)
Sum of Inside Band Monthly netting	(196)	(213)	(212)
Net (Monthly Netting)	13,759	10,403	12,017
Unit Cost (¢/kWh)			
Net (Monthly Netting)	4.385	4.252	4.241
% Change over Base Case	**(1.14%)**	**(1.37%)**	**(1.18%)**
Change over the ±1.5% Case	0.57%	0.76%	0.69%

3. Sensitivity to Improved Forecast Accuracy

The effects of improved wind power forecasting and scheduling is more noticeable. To simulate the scheduling improvement, the hourly imbalance from the persistence method is artificially reduced by a fixed ratio. A two-step process is used to get the desired outcome. To simulate a 15% improvement in forecasting accuracy over the simple persistency method, the hourly imbalance from the simple persistence method is first multiplied by 0.85 and then the value of the scheduled energy for the hour is modified to reflect reduced imbalance. Table 7 lists the test case for 15% improvement in wind forecasting (and scheduling) over the persistence. The out-of-band (±1.5%) imbalance energy decreased 18.5%, but the increase in net revenue is small (about 0.3% more than the base case).

Table 7. 15% Forecasting Improvement and ±1.5% Deviation Band with 90%/110% Rule

±1.5% Deviation Band	**2003**	**2004**	**2005**
Wind Generation (MWh)			
Actual	313,771	244,655	283,378
Scheduled	313,798	244,665	283,412
Imbalance (MWh)			
Total Over-Delivery	27,804	27,703	27,771
Inside Band	6,889	6,636	6,822
Total Under-Delivery	(27,832)	(27,714)	(27,805)
Inside Band	(6,910)	(6,775)	(6,932)
Revenue ($000)			
Base	13,865	10,533	12,107
Outside Band Payment @90%	854	819	837
Outside Band Charge @110%	(996)	(981)	(963)
Sum of Inside Band Monthly netting	(0)*	(6)	(5)
Net	13,722	10,366	11,976
Unit Cost (¢/kWh)			
Net	4.373	4.237	4.226
% Change over the ±1.5% Case	0.30%	0.40%	0.33%

*small negative amount less than $1,000.00

Table 8 lists the results of the test case of a 25% improvement in forecasting accuracy. Compared to the base case, the improvement in wind forecasting decreases the out-of-band energy by more than 30%. However, the net revenue is only increased by a very modest 0.6%.

Table 8. 25% Forecasting Improvement and ±1.5% Deviation Band with 90%/110% Rule

±1.5% Deviation Band	**2003**	**2004**	**2005**
Wind Generation (MWh)			
Actual	313,771	244,655	283,378
Scheduled	313,795	244,664	283,408
Imbalance (MWh)			
Total Over-Delivery	24,533	24,444	24,504
Inside Band	6,755	6,504	6,682
Total Under-Delivery	(24,558)	(24,454)	(24,534)
Inside Band	(6,770)	(6,641)	(6,783)
Revenue ($000)			
Base	13,871	10,535	12,113
Outside Band Payment @90%	726	697	712
Outside Band Charge @110%	(847)	(834)	(818)
Sum of Inside Band Monthly netting	0	(6)	(5)
Net	13,750	10,393	12,004
Unit Cost (¢/kWh)			
Net	4.382	4.248	4.236
% Change over the ±1.5% Case	0.50%	0.66%	0.57%

Discussions and Conclusions

The analyses have shown that the FERC final rule of energy imbalance will have a noticeable impact on the revenue of a wind plant. With the MISO hourly price data and actual hourly wind production data, the rule would reduce the revenue by about 1.9% compared to an "ideal" scenario. With the 90%/110% stipulation in place, changing the deviation band width and forecasting accuracy will not have much of an effect on the result.

The reason is not difficult to understand. The most critical factor for a wind plant's revenue is its actual generation (how much and when it is generated), which determines the gross revenue. The highest scheduling penalty under the 90%/110% rule is about 10%.[5] Improvement in forecasting accuracy and wider deviation bands only address 10% of the revenue (under the 90%/110% rule). Any forecasting strategy will likely end up with a very small imbalance energy over a year. (For shorter periods, the variation could be larger, but our simulation is focused on annual revenue.) The effect of different forecasting methods will place more or less energy within the deviation band that will be netted out at the end of the month, but those imbalances are small to begin with. Consequently, the adjustment on the gross revenue tends to be relatively small regardless of the forecasting strategy and deviation band.

It should be noted that in this analysis the hourly wind power schedule based on a simple persistent forecasting method actually produces very good results. The monthly mean absolute errors (MAE)[6], a common metric to gauge the performance of wind power forecasting methodologies, of this approach are in the 7% to 8% range. The simulated 15% accuracy improvement further decreases the monthly MAE to about 6%. The key to such good forecasting performance is the assumption that the hourly wind power forecasting was produced only 80 minutes before the hour. If the market rules or actual wind power forecasting does not produce a result similar to that in this analysis, the impact of the FERC energy imbalance rule will be even more prominent.

The analysis showed that the actual penalty for wind energy under the FERC energy imbalance rule is not large. It can be argued that this is a reasonable price for wind power plants to pay in order to promote accurate scheduling and maintain system reliability. However wind is not capable of intentionally deviating from the schedule and a small penalty on wind power cannot change the nature of wind power.

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[5] In an extremely simplified case the maximum penalty under the 90%/110% rule will be 10%. For example, if the forecasted hourly energy is constantly over the actual generation for every hour of the year, and the hourly price is constant for the entire year, the revenue would be 10% lower than that without the 90%/110% rule.

[6] Mean absolute error is the average magnitude of differences between the actual and scheduled wind power over a specified period. It is usually expressed as a percentage of wind plant installed capacity.