DRAFT

Thoughts on Wind Integration Tariff Structure

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Background

Structuring a wind integration rate that appropriately differentiates cost causation among wind projects and sends appropriate price signals to wind generation is a challenging endeavor. Few wind integration rates are in place among US utilities, and none so far as I know take account of project size or diversity.

The Bonneville Power Administration (BPA) 2010-2012 rate case is one of the only cases where wind integration rates have been established. Wind integration costs as determined by BPA are recovered using wind project nameplate generating capability as the billing determinant. BPA's "Wind Balancing Service" is a Control Area Service in its rate schedule. BPA requires wind generators interconnected to its system to acquire (or alternatively self-provide) the Wind Balancing Service, consisting of a monthly charge of $1.29 per kilowatt[1]. This rate is further broken down in anticipation of potential self-provision of some or all of these services:

Regulating Reserves-- $0.05/kW
Following Reserves-- $0.26/kW
Imbalance Reserves-- $0.98/kW

The BPA rate was based on the estimated amount of wind on BPA's system during the rate period. One of BPA's main concerns in designing the rate was to recover a specific level of revenues.

Little to no testimony was entered with respect to large versus small wind projects until the very last public hearing when a representative of small wind interests appeared before the BPA Administrator and requested that small wind generators be excused from the rate. In response, BPA waived application of the rate to wind projects under 20 MW during the first year of the rate period. In addition, despite BPA's oft-stated concern over the concentration of wind projects along and around the Columbia River Gorge, nothing in the ensuing rate provided a price signal for encouraging diversity.

RNP believes that the wind integration rate could be better designed to send appropriate price signals to wind projects with respect to size, diversity, and scheduling accuracy. This paper explores

Energy and Capacity as Billing Determinants

Tariff structures based on energy or nameplate capacity as the billing determinant have the significant advantage of simplicity in application. Both energy and nameplate capacity are

[1] A 10 MW wind project would pay $12,900 per month for the Wind Balancing Service: 10MW = 10,000 kW and the charge is therefore 10,000 kW X $1.29 /kW each month. BPA's rate schedule is contained in *Administrator's Final Record of Desicion: Appendix C*, July 2009, pp 65-67.

relatively easily measured, are common billing determinants for other purposes, and the revenues from the tariffs can be reasonably well estimated in advance. However, neither is a particularly good proxy for the individual wind project cost causation. For example BPA's breakdown of its costs indicates that the largest cost-causation component is due to hour-long energy imbalances that must be met by BPA reserve generating capability. Schedule imbalances are directly related to schedule accuracy. One perverse result is that wind projects investing in improved scheduling accuracy can end up subsidizing wind projects doing a poorer job of scheduling their projects.

Although diversity is recognized as an important determinant in reserve requirements, basing rates strictly on energy or capacity provides no price signal to encourage diversity, or discourage co-locating projects. Similarly, it is relatively clear that larger projects tend to have a disproportionately larger effect on overall reserve requirements than small ones.

In addition, similarly-sized projects can have deeply different effects on reserve requirements irrespective of diversity. Take for example two projects with identical nameplate capacity: one with a low capacity factor and relatively erratic output, versus a high capacity factor project with relatively constant output. The first project would require considerably more balancing capacity than the second one. Using nameplate capacity as a billing determinant, they would both be charged identically. Using energy as a billing determinant, the project with lower reserve requirements actually pays more.

This paper explores ideas for aligning charges for wind integration more closely with cost causation to send appropriate price signals while balancing the need to be practically administered.

Ideas for Tariff Structures

Below is a proposal that attempts to balance simplicity and appropriate price signals. As such, it risks failing at both tasks, but it may serve to at least open a conversation.

The proposed structure involves two components. The first component approximates cost recovery for within-hour variability (BPA's regulation and following components) and the second to recover the relatively larger hour-long imbalance component.

<u>Variability Charge</u>

BPA's load following and regulation reserve charges represent cost recovery for sub-hourly variability of wind generation. The correlation among wind generators at shorter time scales becomes very small. It can be shown that for uncorrelated variations, the incremental reserve requirement is proportional to the square of the added variability. This means that on shorter timescales, smaller wind projects contribute less to the reserve requirements than larger ones.

If variability were linearly proportional to nameplate capacity then a charge based on the square of nameplate capacity would capture this effect. However, as the size of wind projects grows, so too does their inherent diversity. Nevertheless, a more appropriate billing determinant would likely be the nameplate raised to the power of n, where n is a number between 1 and 2. The table below shows the effects of such a charge where n=1.5

on existing projects on BPA's system compared to the current regulation and following charges (total $0.31/kw-month).

Plant	Nameplate Capacity MW	Proposed Billing Determinant: Nameplate Capacity raised to the 1.5 power	Annual Charge @ $.31/kW-mon	Annual Charge Based on Proposed billing determinant @ $0.02723 per kwn-month	Proposed charge as percent of existing charge.	Approx Proposed Charge per MWh (32% cap fac) vs $1.33/MWh @ $.31/kw-mon
Vansycle	25	125	$ 93,000	$ 40,842	44%	$ 0.58
Stateline	90	854	$ 334,800	$ 278,971	83%	$ 1.11
Klondike I	24	118	$ 89,280	$ 38,416	43%	$ 0.57
Condon	50	354	$ 186,000	$ 115,518	62%	$ 0.82
Klondike II	76	663	$ 282,720	$ 216,479	77%	$ 1.02
Hopkins Ridge	157	1967	$ 584,040	$ 642,755	110%	$ 1.46
Leaning Juniper	100	1000	$ 372,000	$ 326,735	88%	$ 1.17
Big Horn	200	2828	$ 744,000	$ 924,147	124%	$ 1.65
White Creek	200	2828	$ 744,000	$ 924,147	124%	$ 1.65
Klondike III	226	3398	$ 840,720	$ 1,110,091	132%	$ 1.75
Biglow Canyon	126	1414	$ 468,720	$ 462,117	99%	$ 1.31
Nine Canyon @ 28%	27	140	$ 100,440	$ 45,840	46%	$ 0.61
Goodnoe Hills	96	941	$ 357,120	$ 307,329	86%	$ 1.14
Nine Canyon @ 52%	24	118	$ 89,280	$ 38,416	43%	$ 0.57
Klondike 3a	75	650	$ 279,000	$ 212,221	76%	$ 1.01
Arlington	103	1045	$ 383,160	$ 341,548	89%	$ 1.18
Willow Creek	72	611	$ 267,840	$ 199,616	75%	$ 0.99
Pebble Springs	100	1000	$ 372,000	$ 326,735	88%	$ 1.17
Hay Canyon	100	1000	$ 372,000	$ 326,735	88%	$ 1.17
Wheatfield	97	955	$ 360,840	$ 312,143	87%	$ 1.15
Tuolumne	137	1604	$ 509,640	$ 523,934	103%	$ 1.36
Biglow Canyon Phase 2	149	1819	$ 554,280	$ 594,259	107%	$ 1.42
Windy Flats Dooley (phase 1)	30	164	$ 111,600	$ 53,688	48%	$ 0.64
Windy Flats Dooley (phase 2)	233	3557	$ 866,760	$ 1,162,064	134%	$ 1.78
Harvest	100	1000	$ 372,000	$ 326,735	88%	$ 1.17
Combine Hills	63	500	$ 234,360	$ 163,383	70%	$ 0.93
Star Point	100	1000	$ 372,000	$ 326,735	88%	$ 1.17
Total Annual Revenues			$ 10,341,600	$ 10,341,600		

Note that the tariff is set to ensure that the annual revenue recovery is identical in the two cases. This structure explicitly recognizes the relatively larger costs due to larger projects and lower costs from smaller projects. With n=1.5, wind projects above 130 MW would pay more than they would under the current system, and projects smaller than 130 MW would pay less. The largest project in the list would pay the equivalent of about $1.78/MWh for following and regulation services, whereas the smallest project would pay about a third of that.

Additional work may be necessary to determine the intra-hour variability as a function of nameplate capacity to more accurately determine a value for n.

Imbalance Reserve Charge

This charge is potentially the larger of the two components (as the BPA rate suggests), and costs associated with imbalance are somewhat more under the control of the wind developer. Imbalances can be minimized by improvements in scheduling accuracy. In addition, the imbalance charges are more influenced by the relative diversity of projects (i.e., project siting) than the variability charge because of significant correlations among projects on timescales of an hour or more.

One idea for a structure is to establish a rate that applies to "eligible" hourly schedule imbalances. An hourly imbalance is determined to be eligible if it occurs in the same direction as the balancing area net imbalance. For example if BPA finds itself needing a net incremental generation amount on a particular hour, then wind projects whose schedules exceed their generation levels for the hour would be charged. Similarly, if the system is net surplus in the hour, wind generation above scheduled amounts is charged. Imbalances counter to the overall system balance would not be charged on that hour. This is illustrated in the table below for one 24 hour period. The charge would have to be calculated at the end of each month.

Example Application of Imbalance Tariff

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
Hour	Hourly System Imbalance (MWh)	Wind Generation (MWh)	Wind Sched Imbalance (MWh)	Eligibility	Qualifying Imbalance (MWh)
1	1	125	0	1	0
2	17	124	1	1	1
3	-1	121	4	0	0
4	15	127	-7	0	0
5	10	103	25	1	25
6	13	84	19	1	19
7	-18	122	-39	1	39
8	14	117	6	1	6
9	-32	123	-6	1	6
10	19	103	20	1	20
11	-6	77	26	0	0
12	4	63	15	1	15
13	-20	100	-38	1	38
14	37	114	-13	0	0
15	-9	124	-10	1	10
16	-16	123	0	0	0
17	70	69	54	1	54
18	-5	120	-51	1	51
19	70	118	2	1	2
20	36	83	35	1	35
21	-33	94	-10	1	10
22	-36	97	-3	1	3
23	20	80	18	1	18
24	-13	90	-10	1	10
Totals:	137	2500	35	19	360

The first column shows the hour of the day numbered 1-24. The second column is a tabulation of overall power system imbalances for each hour of the day. The third column represents energy generated from the wind project on each hour. The fourth column is the wind imbalance—the difference between the energy scheduled by the wind project for the hour and the actual energy generated over the hour. Column 5 is a flag that is set to 1 to indicate an eligible wind imbalance, and 0 to indicate ineligibility. The last column tabulates the energy to which the imbalance rate is applied.

Totals at the bottom summarize that energy imbalances were subject to the rate on 19 of 24 hours in this day (highly correlated wind project), for a total of 360 MWh. If, for example, that rate were set at $50/MWh, this project would be assessed $18,100 imbalance costs for the day. Dividing that by the energy produced in the day (2,500 MWh) shows this would be equivalent to a charge of $7.24/MWh of wind generation.

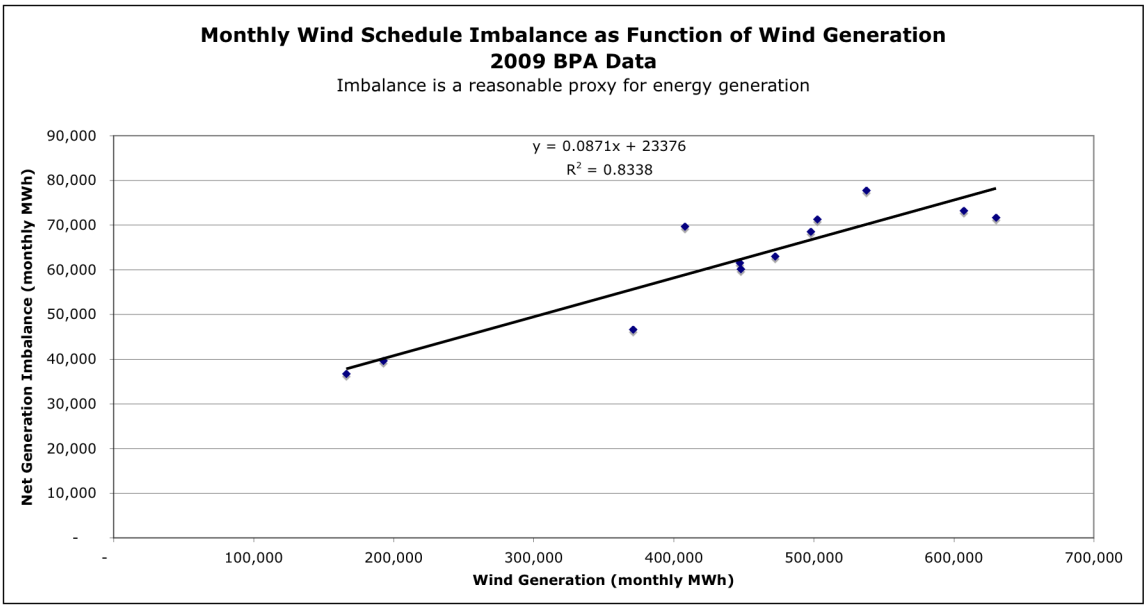
This system explicitly accounts for correlations between the project output and the overall level of imbalance for which reserves are held. In the example, the wind project imbalances contributed to the overall need for balancing services on most hours. A more diverse project would show a lower number of eligible hours, with a completely uncorrelated

project having on average, 12 of 24 eligible hours and a correspondingly lower overall imbalance charge-- likely around 12/19 or 63% of this highly correlated project.

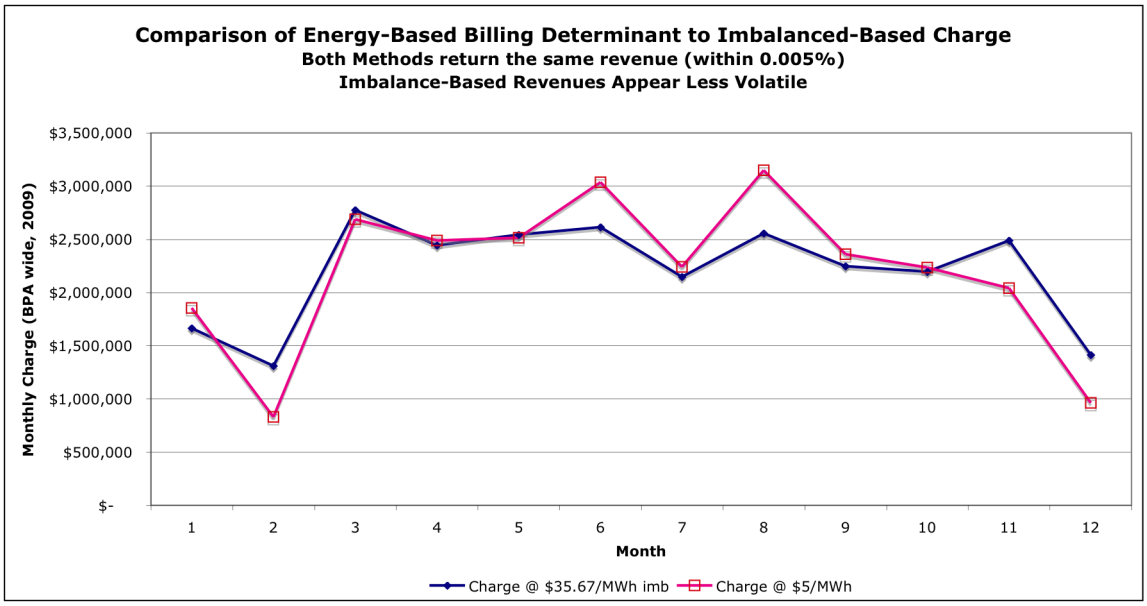
This formulation also gives an appropriate economic signal to forecasting and scheduling improvements that would be represented by lower values in columns 4 and 6 of the table. For example, a 10% improvement in forecast accuracy would result in a 10% reduction in the overall imbalance charge.

One issue raised with using imbalance as a billing determinant is that it may result in greater variation and uncertainty with respect to revenue recovery. It is true that using imbalance as a billing determinant introduces more variability in revenue recovery than using nameplate capacity, evidence from 2009 suggests that imbalance is no more variable than energy production—implying that using imbalance energy as a billing determinant would introduce volatility intermediate between using nameplate capacity and energy production.

The relationship between energy production and generation imbalance was relatively linear on a monthly basis in 2009:



The following chart shows monthly revenues from an energy production charge of $5/MWh and revenues from a charge of $35.67 per MWh of net energy imbalance. Note that the imbalance charge was selected to duplicate revenues received under a $5/MWh and that the month-to-month variability is actually less using the imbalance charge.



Summary

Two ideas are presented that appear to better reflect cost causation and send more appropriate price signals through slightly more complex billing determinants. In the case of the proposal for regulation and following reserves, no additional revenue uncertainty is introduced over using nameplate capacity. The benefit is that the lower integration costs associated with smaller projects can be explicitly recognized.

The proposed method to recover imbalance reserve costs consists of a look-back over the previous month's imbalance. This method has the advantage of rewarding more accurate wind schedules or conversely, penalizing poor wind schedules. In addition, it implicitly provides appropriate incentives for diversity. Although charging based on imbalance introduces additional variability and uncertainty in revenue recovery, it appears to introduce less variability and uncertainty than would be inherent in using energy production as the billing determinant.