Timing is Everything: Aligning States' Wind Integration Tariffs with Capacity Costs

By Travis Kavulla[1]

The timing of wind—sometimes it blows, sometimes it does not—is variable. As an energy resource, wind's periodic lack of availability is mitigated by the expectation that the wind will be blowing somewhere, and that at least some wind resources will always be delivering energy to the grid, even when others are not. Yet in many areas in the West, that expectation has not become a reality, because easy access to transmission and high capacity factors in certain areas have led wind resources to develop in clusters. This clustered development leads to wind that is nearly all "on" or "off" at any given time. The result is greater regulation reserve requirements for balancing wind, at a time when markets in the Western United States are relatively illiquid and additional flexible generation is expensive. This paper is about how regulation can offer a price signal and a potential remedy to this slice of the wind-integration problem.

In the main, this paper presents a case study of a unique rate design, a zonal wind integration tariff, that was adopted by Montana's regulator in reaction to the particular, though not entirely unique, circumstances a local utility has faced in the past decade.

This paper is divided into four parts. First, it describes the peculiarities of markets, utility scheduling practices, and approaches to flexible generation in both Montana, resulting from a complicated history of the state's energy policy, and in the West generally. Second, it describes the technical work undertaken in Montana to ascertain the regulation requirements of wind resources depending on their location in the utility's transmission service area. The third part of the paper describes how that technical work was translated into a tariff adopted in a contested proceeding of the Montana Public Service Commission. Fourth, and finally, the paper offers observations and caveats about the applicability of the zonal integration tariff concept in the wider region.

The regulation adopted in Montana is novel, as yet untested, and subject to modification in further dockets.[2] Nonetheless, it presents an option that regulators, utilities, and wind developers

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[2] Nothing in this paper is meant to convey a pre-determination of issues that may, in the future, be contested before the Montana PSC.

should consider when trying to decide how to price the "integration" or "balancing" or "regulation" service that wind resources must pay for before accessing the grid.

Part I

NorthWestern Energy, the West, and the Integration Challenge

NorthWestern Energy is Montana's largest electric utility. At least it has been since 2000, when it purchased the transmission and distribution assets of the Montana Power Company. The Montana Power Company, or "the Company," as it was simply known in Montana political circles, had occupied a monolithic position in the state's economic, political, even social framework—right up until the point it went bankrupt. Swept up in the fervor of restructuring, Montana's legislature had permitted and encouraged the spin-off of utilities' generating assets from their transmission and distribution plant. The legislation provided that once a utility elected to spin off generation, it could not renege. It would be obligated to be a provider of last resort for electric supply, but its portfolio would be comprised of market purchases.[3] The Company was the only utility among dozens of electric co-ops and another investor-owned electric utility, Montana-Dakota Utilities operating in eastern Montana and the Dakotas, to "deregulate." It sold off its generation assets to a subsidiary of Pennsylvania Power & Light ("PPL") and invested the proceeds in fiber-optic telecommunications infrastructure. Soon bereft of consumers for the new, state-of-the-art services, and unable to obtain regulatory cost recovery of the assets, the Company filed for bankruptcy in 2003. It was a sudden, dramatic failure for the Company, which had existed practically since Montana had obtained statehood, and it shocked the shareholders, pensioners, and Montanans who had come to view the company as a synonym for trustworthiness and enterprise in the state.

When NorthWestern purchased the Company's transmission and distribution assets, it also bought the obligation to be retail consumers' provider of last resort. Since, NorthWestern has controlled relatively little electric generation capability when compared to its peers in the Western United States. A decade after the Montana State Legislature enacted the restructuring

[3] Senate Bill 390, an act generally establishing restructuring requirements for Montana's electric utility industry, was adopted in 1997.

law, lawmakers passed in 2007 a measure known as "re-regulation."[4] The legislation contained two essential elements. First, it locked in Montana consumers to being supplied by NorthWestern, so long as they previously did not choose a supplier during the deregulation era. Second, it allowed NorthWestern to own generating facilities once more. Regardless, NorthWestern is unlike most other utilities in the West, which command whole fleets of generators in service of regulating the variability of loads and energy resources. NorthWestern owns generation in Montana representing 31 percent of its Montana retail load. This is the lowest among Western electric utilities. PacifiCorp, a six-state utility that is the largest investor-owned utility in the northwest, owns 109 percent of its retail load; Idaho Power, 108 percent.[5] On either extreme, NorthWestern and its highly vertically integrated counterparts find themselves profoundly exposed to a market, for purchases when short and sales when long, in which trades for energy supply and ancillary services are not conducted through a regional automated dispatch, as they are in areas of the country where trades are transacted via a central market operator. Trading energy in most of the West means picking up the phone to a counterparty and arranging for delivery of energy products and, separately, transmission services, sometimes across multiple Balancing Authorities ("BAs").[6]

While a vertically integrated utility may have oversupply difficulties that necessitate unloading a surplus, utilities like NorthWestern have a related but opposite problem. They must build a portfolio of short- and medium-term products to supply their load. Those products often are take-or-pay contracts delivered on an hourly basis. Although NorthWestern offers intra-hourly scheduling like many other transmission operators do, the dominant practice of Western energy supply groups is hourly scheduling. When NorthWestern must shape its generation or load to balance the intermittency of the other within any given hour, there is little in the way of owned or contracted resources to call upon. In areas where organized markets send more frequent energy dispatch signals, the concept of balancing within the dispatch interval if a more discreet, minutely product. For NorthWestern, and others in the West, the regime of hourly scheduling

[4] House Bill 25, an act generally revising the electric utility industry restructuring and customer choice laws, passed the legislature in 2007, almost exactly 10 years after restructuring became law.
[5] NorthWestern Energy's 2011 Resource Procurement Plan, p.12.
[6] Only in California and Alberta does an independent system operator exist. Additionally, a proposal to establish security constrained economic dispatch on a five-minute basis has been floated by PacifiCorp and the California ISO.

has meant balancing is a behemoth. The "regulation and frequency response" capability that transmission operators provide in the West is a product that must balance loads against resources over the course of an hour—and a more substantial possibility for deviation.

NorthWestern has little ability to influence the regional market in which it does business, but it nonetheless remains responsible for providing energy supply and transmission to its regulated retail customers, and for providing transmission service, including ancillary services, to its considerable number of wholesale customers, including electric co-operatives, "choice" customers left over from deregulation and supplied by PPL, and the Bonneville Power Administration. Failure to adequately balance loads and resources is a threat to system reliability, and could result in major penalties for NorthWestern, even if the dysfunction and illiquidity of Western markets were the underlying cause.

NorthWestern had consistently required at least 60 megawatts of regulating capacity from the mid-1980s until 2006.[7] When the Montana Legislature passed the state's Renewable Portfolio Standard in 2005, it was clear that variable energy resources would be added to NorthWestern's system and would significantly complicate a product that had before been needed solely for balancing loads.[8] With the addition of a contract for the output of a 135-megawatt wind facility in central Montana to its supply mix in 2005-2006, NorthWestern added an additional 15 megawatts of contracted regulation resources for a total of 75 megawatts. Shortly thereafter, NorthWestern found itself unable to consistently meet the CPS2 reliability criteria in the summer of 2008. It procured an additional 10 megawatts of contracted regulation supply, resulting in a total of 85 megawatts of regulation contracts.[9] Its counterparties in these transactions were hydro-owning public utility districts and power marketers like Powerex. Ironically, the party that might have been in the best position to provide regulation services, PPL, the owner of the

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[7] *NorthWestern Corporation Revisions to Schedule 3, Regulation and Frequency Response Service, of NorthWestern's Open Access Transmission Tariff*, 121 FERC ¶ 61,204, p. 15 (2007).

[8] The Montana Renewable Power Production and Rural Economic Development Act is codified in Sections 69-3-2001–2010 of the Montana Code Annotated.

[9] *Application for Approval to Construct and Operate the Dave Gates Generating Station to Supply Regulation Service for NWE's Montana Electric Operations and Montana Transmission Control Area*, Docket No. D2008.8.95, Order No. 6943a, ¶ 65 (May 20, 2009). DGGS first came before the MPSC when NorthWestern Energy on August 25, 2008 filed its case in Docket D2008.8.95 for advanced approval to construct and operate the facility. On May 20, 2009, issued its Order No. 6943a providing an advance determination of the prudence of construction of the facility. On March 21, 2012, the MPSC issued its Order No. 6943e in the same Docket, approving the final costs of DGGS as it was constructed.

old Company hydro assets, was precluded from doing so by the so-called *Avista* restriction, which prevents most marketers from providing ancillary service products at market rates.[10]

With its third party contracts for regulation resources expiring, NorthWestern conducted Requests for Proposals in both 2006 for up to 90 megawatts of regulation resources,[11] and repeated the process in 2007.[12] The resulting contracts terminated in December 2010 and early January 2011.[13] The responses reflected diminishing availability of regulation resources in the Pacific Northwest at increasing prices, as the need for regulation throughout the West increased concomitant with the construction of variable energy resources that provided a new demand for a service once needed only to regulate loads' variability. NorthWestern, although able to integrate the Judith Gap facility committed to retail customers, was in a difficult position in terms of integrating other wind projects.

During the same time, wind developers like the established international firms NaturEner, from Spain, and Gaelectric, from Ireland, were showing a keen interest in Montana resources.[14] But NorthWestern felt that it was largely helpless to accommodate them. With an average retail load of about 800 megawatts, balancing a merchant wind farm of hundreds of megawatts was a tall order—an impossible one, in NorthWestern's view. In 2008, the merchant NaturEner, whose 210-megawatt Glacier Wind project in northern Montana whose renewable energy credits were contracted to California counterparties, found NorthWestern unable to cost-effectively fulfill its obligations as the incumbent transmission operator to provide balancing services. NorthWestern offered to make good on its legal obligations under its open access transmission tariff by building a gas generating facility to provide regulation service. The price was, for those large merchants, prohibitively expensive. In a move that proved a crafty solution, even if it increased

[10] *Avista Corp.,* 87 FERC ¶ 61,223, order on reh'g, 89 FERC ¶ 61,136 (1999). The theory behind the ruling is that robust markets do not exist for nuanced products like ancillary services, unlike, say, for firm energy supply. The potential reversal of the holding, at least in part, is the subject of a recent FERC notice of inquiry and proposed rulemaking, which, if adopted, would have the hoped-for effect of increasing liquidity in ancillary-services markets. Docket No. RM11–24–000, 139 FERC ¶ 61,245

[11] MPSC Order No. 694a, ¶67.

[12] Id., ¶72.

[13] Prefiled Direct Testimony of Michael R. Cashell, pp. 7-8. 121 FERC ¶ 61,204

[14] The exuberance to construct remotely located, high-capacity-factor wind farms in Montana and Wyoming has diminished somewhat as a result of a California law that requires, for the most part, the physical delivery of electricity into California to meet the state's renewable portfolio standard.

the balkanization of the region, NaturEner simply started its own balancing authority, the Glacier Wind BA, the first renewable-only BA in the country.[15]

This is the setting in which NorthWestern found itself in 2008, when it chose to build what became known as the David Gates Generating Station (DGGS), a 150 megawatt facility fired by aero derivative gas combustion turbines capable of providing 105 megawatts of regulation service.[16] The Montana Public Service Commission ("Commission") agreed with NorthWestern's observation of a trend toward illiquidity in the regulation market and, in accordance with Montana's "re-regulation" statute, conditionally pre-approved a plant with three Pratt & Whitney simple cycle gas generators. The 2009 order of the commission was premised on the existence of "compelling evidence of the imprudence and risk of continuing to rely exclusively on its longtime practice of contracting with other utilities in the region to meets its need for mandatory regulation service."[17] The Commission approved NorthWestern's regulation requirements as follows, deriving its estimates from the GENIVAR study discussed in Part II:[18]

Allocation of Regulation Costs		
	Capacity (MW)	Allocation %
Traditional/Historic Regulation Requirements	60	
Wholesale Customers Load Ratio Share (35%)	21	20%
Retail Supply Customers Residual Share (65%)	39	
Retail Supply Customers Wind Integration (lower end)	45	
Total Retail Customers Regulation Needs	84	80%
Total Regulation Needs	105	

[15] The BA is operated by Constellation Energy, based in Houston. NaturEner's wind capacity in the area has since grown to 400 Megawatts.
[16] Its regulation capabilities are less than its nameplate capacity because of the need to run the station at a mid-point to provide decremental regulation.
[17] Docket No. D2008.8.95, Order No. 6943a, ¶ 219 (May 20, 2009). During the Montana Public Service Commission's decisionmaking process on the matter, NorthWestern has also sought cost-recovery at the Federal Energy Regulatory Commission ("FERC") for services provided under Schedule 3, Regulation and Frequency of its Open Access Transmission Tariff. In a hotly contested proceeding, the FERC administrative law judge mostly ruled on behalf of intervenors, denying NorthWestern recovery of all but a portion of costs that the Montana commission attributed to wholesale customers. The Montana commission, in its own order and ins appearance before FERC, had argued that it was unreasonable to disallow cost-of-service plant that provided an amount of regulation service that was equal to what it previously had been procuring from third parties. In the Montana commission's view, as expressed in post-hearing briefing, the FERC ALJ's decision would punish a utility that took charge of an untenable situation, and cause a chilling effect on the development of flexible generating resources throughout the Western United States. *See* Brief on Exceptions of the Montana Public Service Commission, , 121 FERC ¶ 61,204 (Oct. 22, 2012). The FERC itself has yet to rule on the exceptions filed by parties to the ALJ proceeding.
[18] Docket D2008.8.95, Ord. 6943e, ¶ 33 (Mont. Pub. Serv. Commn. Mar. 21, 2012).

Part II

Not All Wind is Equal

When wind generation first became part of Montana's energy mix, NorthWestern's energy supply group had little experience scheduling generation resulting from intermittent resources. And, on the other side of the business, NorthWestern's transmission utility had little experience providing the frequency response and regulation service that wind energy's intermittency required. Beyond inexperience, neither of these parts of the utility, as we have seen, had substantial owned generating resources with which to counter-schedule or balance wind. They were reliant almost entirely on the market for such services.

The impetus for renewable development in Montana was, as everywhere, driven to some degree by public policy. But even absent the Montana state mandate to obtain 15 percent of retail supply from renewables by 2015, the wind resource in Montana is robust and, buttressed by federal tax incentives, wind generation can be a least-cost resource in the state—so long as balancing issues can be grappled with in an economic manner.[19]

The DGGS regulating facility was an expensive proposition. NorthWestern assumed an integration factor of 18% for wind facilities.[20] If the DGGS embedded and operating costs were applied on a *pro rata* basis to wind, the cost to integrate wind would be a whopping $14.99 on top of every megawatt-hour of wind generated.[21] That price would go up if NorthWestern's assumed integration factor were too low; it would go down if the assumed integration factor were too high. It was crucial for NorthWestern to explore the impacts of increased wind penetration on regulation service.

NorthWestern contracted with GENIVAR Consultants Limited Partnership, a firm with experience conducting wind integration studies in Alberta and Saskatchewan, to explore the issue. Invenergy's Judith Gap wind farm, under a long-term contract to NorthWestern, and a

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[19] The long-term cost of Judith Gap is between $30 and $40 per megawatt-hour, including an implied integration cost that represents not just the variable costs of operating DGGS but an assignment of fixed costs as well.
[20] That is, a 10 megawatt wind farm would require 1.8 megawatts in regulating reserve. *See* Prefiled Direct Testimony of John B. Bushnell, p. 10, Jan. 17, 2012, Docket D2012.1.3, before the Montana Public Service Commission.
[21] Prefiled Direct Testimony of Todd A. Guldseth, p. 8, May 31, 2011, Docket D2011.5.41, before the Montana Public Service Commission.

small qualifying facility that is seasonally contracted to NorthWestern, provided confidential access to the wind production data to GENIVAR. Eight other high-tower anemometers owned by wind developers also agreed to share their data, and the consulting firm used a multi-turbine power curve approach to simulate time series production data as if a wind generator were located on those sites.

In 2011, the GENIVAR consulting firm released its work, which it described as "an assessment of time-varying characteristics of potential wind power development scenarios and its impact on electric system balancing."[22] The report attempted to isolate the impact of load's impact on regulation needs, and then proceeded to derive the regulation needed for wind regulation in various scenarios, using the installed capacity as a base case upon which to build out 14 scenarios. Three "dispatch sensitivities" were also modeled, assuming a scenario where NorthWestern's installed wind capacity more than doubled, but where the utility used techniques including 30-minute wind forecasting, wind curtailment, and intra-hour supply adjustment to mitigate within-hour transmission balancing needs.

The study found that wind resources located in diverse areas of the NorthWestern BA required fewer regulating reserves for balancing than did wind resources that clustered in a particular area. This was to some degree an intuitive conclusion, albeit helpfully verified by GENIVAR. The GENIVAR study was not so much striking in its comment on this basic proposition of geographic diversity; it was striking in the degree to which the absence of geographic diversity drove regulation needs.

The status quo reflected a need of 96 megawatts of regulation service for both load and 144 megawatts of wind generation, if NorthWestern was to pass its reliability standard.[23] When another 50 megawatt wind project was added nearby the 135 megawatt Judith Gap wind farm,

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[22] GENIVAR Consultants, Ltd., "NorthWestern Energy Montana Wind Integration Study," 2011. Available online at: http://www.northwesternenergy.com/%5CDocuments%5CDefaultSupply%5CMTWindIntegrationStudy.pdf (accessed May 16, 2013).

[23] The relevant reliability standard is the Control Performance Standard 2, or CPS2, which measures the amount of 10-minute periods in which a BA falls outside of its L10, a measure of the deviation of scheduled loads and resources that acts as a proxy for deviations for the 60 Mhz frequency of the interconnection. CPS2 requires a passing score of 90 percent—in other words, in no more than 10% of the 10-minute intervals per month may a BA's deviation be beyond, whether above or below, its L10 value. For GENIVAR, the study assumed a comfort zone of a 92% pass rate, and also ran other scenarios against a 94% pass rate threshold.

the regulation burden increased to 117 megawatts, a 21-megawatt increase, or a regulation burden for the farm of 42% of its nameplate capacity. Meanwhile, a 50-megawatt project added to northern Montana results in a regulation requirements burden of 101 megawatts. This 6-megawatt increase implies a 12% integration factor for the wind farm, 3000 basis points higher than the "co-location" scenario. A location on the western side of the Rocky Mountain Front showed an impact of only a single megawatt for a new 50-megwatt installation—a 2% integration factor.

In one remarkable scenario, four 10-megawatt projects typical of the size of the small wind facilities that take service under NorthWestern's Qualifying Facility tariff and four other 2.5 megawatt installations (a total of 50 megawatts, diverse from each other and from Judith Gap) yielded a small *decrease* in the total number of required regulation reserves. In this scenario, as well as others, wind resources appeared to be balancing themselves.[24]

Part III

NorthWestern Adopts a Zonal Wind Integration Tariff

The GENIVAR study undermined the practice of picking a single "integration factor" to assess wind integration charges. But could it be replaced with something that was equitable and easily understood?

In this context of regulation scarcity and the increasing value of system flexibility and diversity, tariff filings under the Public Utility and Regulatory Policies Act of 1978 ("PURPA") offer one opportunity to encourage new wind farms to geographically balance existing wind farms. As an electric utility subject to PURPA's requirement to purchase energy and capacity made available from qualifying facilities ("QFs"), NorthWestern makes biennial filings to update standard rates available to QFs 10 megawatts or smaller.[25]

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[24] A replication of the GENIVAR study's findings regarding various wind development scenarios is Appendix A.
[25] Federal law requires state regulatory authorities to set "standard rates for purchases from [QFs] with a design capacity of 100 kilowatts or less," and permits standard rates for larger QFs. 18 C.F.R. § 292.304(c). In 1992, the Montana commission adopted an administrative rule setting the eligibility threshold at 3 megawatts. The commission amended its rule to 10 megawatts in 2007.

In response to NorthWestern's standard rate filing in 2008, the Montana Commission asked NorthWestern to provide testimony on the merits of setting standard, long-term wind integration charges. NorthWestern ultimately proposed a rate of $2.35 per kilowatt-month, which the Commission accepted.[26]

In 2010, NorthWestern proposed to retain the existing wind integration tariff under which wind QFs selecting certain standard rate options were required to

> [C]ontractually agree to provision of wind integration services for the term of the Agreement and may either self-supply sufficient within-hour regulating reserves under terms acceptable to NorthWestern or pay the Utility for these services according to the Wind Integration Tariff (WI-I). Payment to the Utility for selection of service through WI-I will result in a deduction from the total monthly payment made to the QF to reflect the provision of integration services.[27]

The commission noted that the rate reflected the price of integration services that NorthWestern purchased from other utilities before it built the DGGS, but preserved the tariffed rate of $2.35 per kilowatt-month.

In its 2012 standard rate proceeding, NorthWestern proposed to update the wind integration rate to $1.48 per kilowatt-month based on the incremental cost of providing integration service using DGGS, its current source of wind integration service. In prefiled testimony, one of NorthWestern's witnesses observed that the results of the GENIVAR Study

> [I]ndicate that the size of wind farm additions and their location relative to existing and other added wind farms impact the amount of regulation that the NWE transmission system requires. The closer the wind farms are to existing wind farms and to each other – and the greater the size of the wind farms – the greater the regulation required for the NWE transmission system.[28]

United Materials of Great Falls, Inc. and Exergy Development Group (collectively, "UMX"), owners of an existing small wind farm who hope to develop other projects, opposed NorthWestern's proposal to set a single wind integration rate, contending that it did not allocate costs equitably, encourage efficient location decisions, or take into account the results of the

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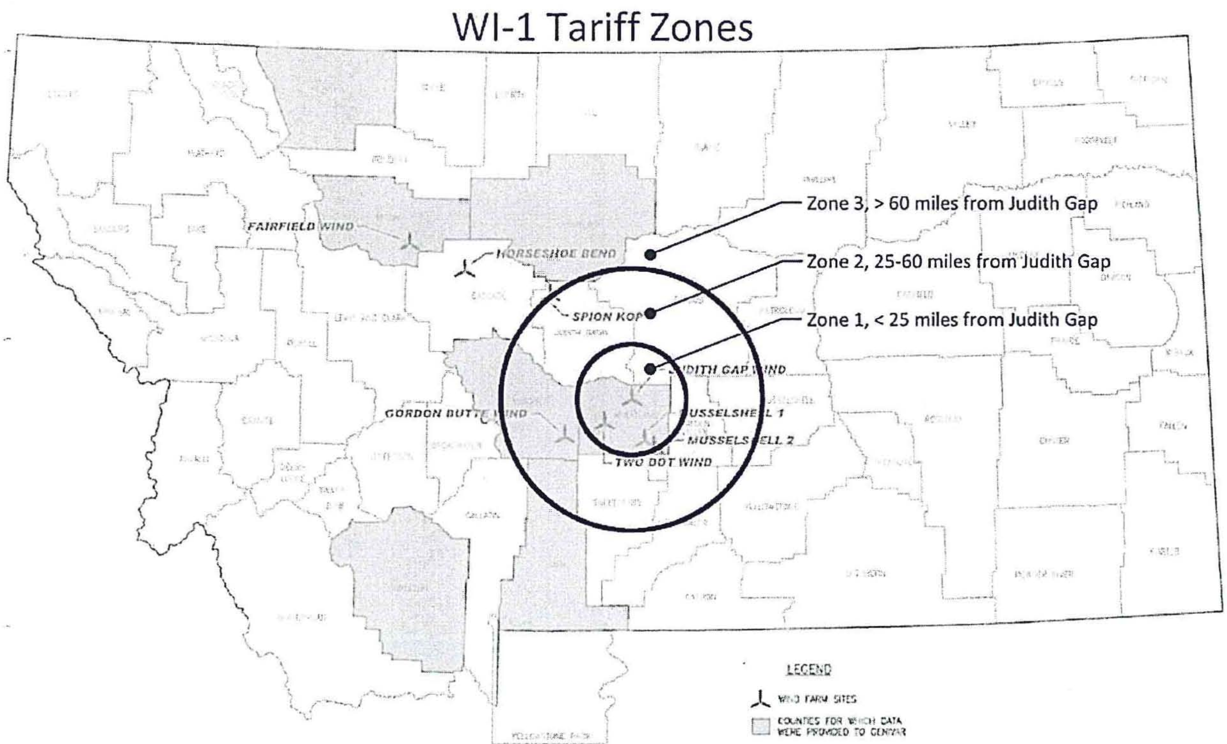
[26] *Application for Tariff Adjustment*, Docket D2008.12.146, Ord. 6973d, ¶¶ 76, 134 (Apr. 13, 2010).
[27] *Application for Approval of Avoided Cost Tariff Sched. QF-1 for New Qualifying Facilities*, Docket D2010.7.77 (July 30, 2010).
[28] *Id.* at Direct Test. of Ray W. Brush, p. 5.

GENIVAR study, which was intended to inform allocation discussions.[29] UMX proposed three wind integration factors based on proximity to the Judith Gap wind farm: An integration factor of almost 26 percent within 25 miles ("Zone 1"), almost 15 percent between 25 and 60 miles away ("Zone 2"), and just over 5 percent for wind QFs more than 60 miles from Judith Gap ("Zone 3").[30]



The Montana commission adopted the zonal pricing approach proposed by UMX. For Zone 1, the Commission established an even stronger zonal signal than that proposed by UMX, establishing a 38% integration factor.[31] Under this approach, the commission set the long-term integration rate at $1.09 per kilowatt-month for wind QFs located within 25 miles of Judith Gap, $0.40 per kilowatt-month for wind QFs located within 25 to 60 miles, and $0.15 per kilowatt-month for those located more than 60 miles away.[32] The costs are based on the marginal cost of

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[29] *Application for Approval of Avoided Cost Tariff Sched. QF-1*, Docket D2012.1.3, Ord. 7199d, ¶ 58 (Nov. 20, 2012).
[30] *Id.* at ¶ 59.
[31] *Id.* at ¶ 66.
[32] *Id.* at ¶ 67.

operating the DGGS; because the WI-1 tariff does not include the costly embedded fixed capital cost of DGGS, the service remains relatively cheap, even in Zone 1. If and when DGGS runs out of capacity, the rates likely would be re-set on the basis of the cost of other regulation resources, but the integration factors under the zones would remain the same, unless further renewable development significantly reconfigured the zonal impacts on regulation needs. The WI-1 rate is deducted from the standard avoided cost rates paid to QFs, which remain free to "self-supply" integration service, and presumably will if they can do so for less per kilowatt-month than the tariffed rate.

Part IV

The Zonal Tariff: A Partial Solution for Inefficient Markets

The lessons from NorthWestern, GENIVAR, and the Montana example suggest that other BAs that experience dramatic ramp events should consider attempting to establish a price signal for future wind development that emphasizes the regional nature of regulation requirements. At present, no other BA appears to have a zonal tariff for renewable integration.[33]

In some circumstances, the impact on a BA's regulating burden caused by a wind farm's siting decision might not be terribly important. If regulation resources are plentiful and low-cost, regulation can be a rounding error; for a long time, hydroelectric resources fit this mold, since they were easy to ramp up and down simply by releasing more or less water through a dam's spillgates, instead of running it through a dam's generator. However, in the northwest, relicensing and environmental regulations that safeguard fish populations have limited most dams' ability to function in that manner, while a surge in renewable development has taxed the operational capabilities of the remaining hydroelectric capacity.[34] Elsewhere, a central market that dispatches energy on more rapid intervals can diminish the need for regulation—it becomes a product that balances only 5- or 15-minute periods, rather than over an entire hour. Or, even if

[33] K. Porter, et. al., "A Review of Variable Generation Integration Charges," National Renewable Energy Laboratory, March 2013.
[34] "Spilling" water results in excessive levels of total dissolved gas which causes gas bubble trauma in fish, including federally protected salmonids. The inability of the Bonneville Power Administration to turn off its hydro facilities, along with low loads and a surge of wind, led the BPA to adopt an oversupply protocol that involuntarily curtails wind assets in the region. *See* Administrator's Final Record of Decision, BPA's Interim Environmental Redispatch and Negative Pricing Policies, May 2011.

a BA mostly balances hourly schedules, a large utility with a sizable generating fleet can re-dispatch its resources within an hour to better meet its schedule by mitigating significant ramping events, while the BA runs a resource equipped with automatic generator control to clear up the less significant frequency deviations.[35] And either a central market or a large BA will have the advantage of aggregating the variability of intermittent resources; deviations from schedules of loads and resources are thus added together, counterbalancing one another and creating a schedule error that is less as a whole than the individual parts.[36]

But there are places where the burden of regulation is highly significant. Montana is one of those places, and NorthWestern is not well-positioned to avail itself of techniques that other utilities have used to make integrating wind a much easier task. It is not part of a central market. Its BA balances small loads and resources. It relies entirely on a gas-fired generator for regulation service. It offers intra-hourly scheduling to transmission customers, but has never scheduled its own loads on anything but an hourly basis. The consequence if that regulation service is scarce and expensive. GENIVAR's work was an indication that while freeing up additional megawatts of regulating reserve might be difficult, making the most out of the megawatts one had was crucial.

Many other Western BAs find themselves in similar, if not identical, situations. While few BAs in the West have the distinct characteristics of NorthWestern, virtually all of them lack access to a centrally dispatching market, and many of them balance considerable intermittent resources against a relatively small native load. Moreover, utilities and regulators alike in the West are concerned that flexible generating capacity is not being properly incented, paid for, and constructed.

The poster child of wind integration difficulties in the Western United States has been the Bonneville Power Administration. In the fall of 2007, the BPA was responsible for using its transmission system to balance less than 1,000 megawatts of wind capacity. Five years later, the

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[35] GENIVAR, pp. 45-46.

[36] This is the premise of many of the benefits derived from an energy imbalance market. See M. Milligan, et. al., *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, National Renewable Energy Laboratory on behalf of the PUC EIM Working Group, March 2013. http://www.nrel.gov/docs/fy13osti/57115.pdf (accessed May 16, 2013).

BPA was responsible for balancing over 4,500 megawatts of intermittent wind energy.[37] The majority of BPA wind has located in the Columbia Gorge, and ramps of 4,000 megawatts over mere hours are common. BPA offers a discounted integration rate for wind that schedules on a committed intra-hourly basis, because it will tend to have fewer balancing needs. At the same time, BPA's wind integration tariff does not have any incentive for diversity of location.[38] In the face of efforts to make integration an easier task through a market that uses a flow-based, security constrained economic dispatch to aggregate variability and signal low-cost generators to fire up when needed, many Bonneville stakeholders have been lukewarm, warning such a market "is not a means by which market participants or system operators can procure the capacity necessary to reliably meet their load and transmission service needs."[39] That is true enough—but underscores the case for preserving scarce flexible capacity assets through ratemaking.

The more diverse the wind regime in a particular BA, or between multiple BAs who share reserves and aggregate variability, the less profound ramping events will tend to be, diminishing the need for excess capacity in the long run. If, for instance, the wind regime in central Montana is aggregated with the BPA wind regime, at least one wind developer has shown wind energy supply becomes more stable and ramping events become less severe.[40] The Northwest Power Pool Member Initiative's recent study of a security-constrained economic dispatch market, meanwhile, suggests that aggregating resources across the diverse northwestern region could yield upwards of $90 million annually because of the decreased use of flexible reserves.[41]

Even without these regional solutions, however, individual BAs should consider the potential for regional diversity within their own footprint. Except for small BAs who do not have the potential for geographic diversity, it seems intuitive that GENIVAR's findings for NorthWestern

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[37] For a visual example of wind generation capacity in the BPA balancing authority, see: http://transmission.bpa.gov/business/operations/wind/WIND_InstalledCapacity_PLOT.pdf (accessed May 16, 2013).

[38] Administrator's Final Record of Decision, 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12), July 2011, pp. 189-470.

[39] Draft Straw Proposal for a Phased Approach to Implementation of a Voluntary Energy Imbalance Market, Northwest Power Pool Members Committee, May 2, 2013, p. 1.

[40] Charles R. Shawley, "The Impacts of Integrating Montana Wind Resource on Transmission System Operators and Utilities in the Pacific Northwest," 2011, pp. 4-5. The document is an internal report for the wind developer Gaelectric. http://www.gaelectric.ie/wp-content/uploads/GaelectricMontanaWind-PNWAnalysis.pdf (accessed May 16, 2013).

[41] NWPP MC May 20, 2013 meeting.

would apply equally to other geographically large BAs. The question, then, becomes one of ratemaking: is it reasonable to establish rates that distinguish between individual renewable generators on the basis of their operating characteristics?[42] Not for nothing do Bonbright's principles of ratemaking include "practical attributes of simplicity . . . and feasibility of application."[43] In a perfectly economic world, every wind farm will have its own regulation burden per megawatt of installed capacity—and its own rate. Clearly, that is impractical. On the other hand, a standard dollars-per-megawatt-month integration tariff can be established, but that incents the clustering effect, even when it has a tendency to exacerbate regulation needs.

For NorthWestern, the context that led to the establishment of a zonal integration tariff was a PURPA proceeding, where a generator gets paid for energy, but also must pay something back for integration service. For other utilities, an implied integration cost is an important part of integrated resource planning that is intended to surface the least-cost resource for the benefit of ratepayers. Transmission utilities, operating within the context of their open access transmission tariffs, have the obligation to charge renewable generators an integration tariff different than the traditional Schedule 3, regulation and frequency response, or Schedule 9, generator imbalance, charges as a result of FERC's 2012 Order 764.[44] These filings, if utilities elect to make them, should at least contemplate proposing a zonal integration tariff in BAs where existing wind demonstrates a problematic clustering.

Each utility's rates are driven by its peculiarities. As explored above, there are many situations when a zonal integration tariff would be needlessly complex given other mechanisms that exist for coping with renewable integration. Such a tariff could seem a pointless bauble in a robust regional market that used security-constrained economic dispatch and locational marginal pricing signals to derive the benefits of diversity across a wide geographic footprint. But for utilities that find themselves isolated from markets and short on flexible capacity, zonal tariffs are an important new tool to consider in encouraging efficient siting of intermittent resources.

[42] FERC, as a policy matter, has seemed to answer "yes" to this question, although in a context different than zonal integration charges. *See Integration of Variable Energy Resources*, 139 F.E.R.C. ¶ 61,246, pp. 222-223 (June 22, 2012)

[43] James Bonbright, *Principles of Public Utility Rates*, (Public Utility Reports: Arlington, 1988), p. 384.

[44] *Integration of Variable Energy Resources*, 139 F.E.R.C. ¶ 61,246, pp. 222-223 (June 22, 2012).

Appendix A: GENIVAR's Assessment of Wind Facilities' Impacts on Balancing Requirements

Scenario Name	Wind Power Capacity (MW)	Scenario Description	Required Regulating Reserve Range for Targeted Performance (MW)	
			of 94% CPS2	of 92% CPS2
A	144	Existing wind resources for the historical study period: 135 MW at Judith Gap and 9 MW at Horseshoe Bend	110	96
B	0	All wind resources removed	69	59
C1	154	Scenario A with one 10 MW project added near Judith Gap in Wheatland County	113.8	97.1
C2	154	Scenario A with one 10 MW project added distant from Judith Gap in Madison County	108.7	92.6
C3	154	Scenario A with one 10 MW project added distant from Judith Gap in Glacier County	109.2	94.6
D1	194	Scenario A with one 50 MW project added near Judith Gap in Wheatland County	136	117
D2	194	Scenario A with one 50 MW project added distant from Judith Gap in Madison County	112	97
D3	194	Scenario A with one 50 MW project added distant from Judith Gap in Glacier County	120	101
D4	194	Scenario A with one 17.5 MW project added in Madison County, one 17.5 MW project added in Wheatland County, and one 15 MW project added in Glacier County	120	101
D5	194	Scenario A with four 10 MW projects and four 2.5 MW projects diversified from each other and from Judith Gap	105	95
E1	294	Scenario A with one 150 MW project added near Judith Gap in Wheatland County	209	181
E2	294	Scenario A with one 150 MW project added distant from Judith Gap in Madison County	149	130
E3	294	Scenario A with one 150 MW project added distant from Judith Gap in Glacier County	163	144
E4	294	Scenario A with a 50 MW project added in each of the following counties: Madison, Wheatland, Glacier	144	126
E5	294	Scenario A with one 50 MW project, two 25 MW projects, and five 10 MW projects diversified from each other and from Judith Gap	132	114
F	594	Scenario A with two 150 MW projects, one 50 MW project, three 25 MW projects, and two 12.5 MW projects diversified from each other and from Judith Gap	223	194
Sensitivity 1	294	Scenario E5 wind with 30-minute wind forecasting	114	98
Sensitivity 2	294	Scenario E5 wind with wind curtailment	114	94
Sensitivity 3	294	Scenario E5 wind with intra-hour supply adjustment	119	100