Wind Power Costs/Benefits

Prepared by Sonja Nowakowski for January 24, 2008 ETIC meeting

The 2007-08 Energy and Telecommunications Interim Committee (ETIC) adopted a work plan that dedicated .15 FTE to a study of the costs and/or benefits ratepayers may see if the state invests in further development of wind power.

Wind's variability can increase the day-to-day operating costs of a utility system. With rising coal and gas prices, however, wind is becoming a competitive player. Concerns abound that large, utility-grade wind turbines can't be installed on the distribution grid without upgrades, resulting in higher costs being passed on to ratepayers. The cost of wind integration also can grow as the percentage of wind increases on the interconnected system. Overall, however, the economics of wind energy are largely a function of a project's size, the wind resource, policy incentives, and financing. Cost recovery can be a threshold issue that varies among areas and utilities.

This information is intended to provide an overview of factors that contribute to the costs of wind energy on a utility-scale size. Wind integration costs are often driven by the need to "secure additional operating flexibility on several time scales to balance fluctuations and uncertainties in wind output."[1] This information aims to summarize some of the most recent studies that include an analysis of wind integration costs and a review of related transmission issues. An upcoming panel discussion and public comment period will allow ETIC committee members to hear the various opinions about the costs of integrating and transmitting wind energy in Montana.

The costs associated with wind can be reviewed in two areas. One is wind integration, or the impacts of adding wind into a utility's operations. A second is the cost of wind as it relates to marketing that product or having adequate transmission to get it to market. From many utility operator's point of view the cost of integration or ancillary costs are critical. From the production perspective, the importance of increasing transmission lines and the ability to get wind power, or any source, to market is key.

Operations Perspectives

Wind Integration Studies

[1] *The Northwest Wind Integration Action Plan*, March 2007, page 27.

Wind brings additional costs related to integration and transmission. A study by the Department of Energy, Energy Efficiency and Renewable Energy division finds that at least two recent studies show wind integration costs are about $5/MWh, or less, for wind capacity penetrations up to 15% of the peak load where the power is delivered.[2] However, there is debate about whether average or "typical" integration costs can truly be determined. Some states and utilities have completed or are in the process of completing wind integration studies to determine individualized costs. About 200 wind integration studies have been completed around the world.[3] Wind integration studies that evaluate these issues, particularly transmission access, have been completed by public and private entities. Findings related to some of those studies are provided below.

Key Results from Major Wind Integration Studies Completed 2003-2006

			Cost ($/MWh)				
Year	**Study**	**Wind Penetration**	**Regulation**	**Load Following**	**Unit Commitment**	**Gas Supply**	**TOTAL**
2003	Xcel - Uwig	3.5%	0	0.41	1.44	na	1.85
2003	We Energies	4%	1.12	0.09	0.69	na	1.90
2003	We Energies	29%	1.02	0.15	1.75	na	2.92
2004	Xcel -- MNDOC	15%	0.23	na	4.37	na	4.60
2005	PacifiCorp	20%	0	1.6	3	na	4.60
2006	CA RPS (multi-year)	4%	0.45	trace	na	na	0.45
2006	Xcel - PSCo	10%	0.2	na	2.26	1.26	3.72
2006	Xcel-PSCo	15%	0.2	na	3.32	1.45	4.97
2006	MN -MISO 20%	31%	na	na	na	na	4.41

Source: National Renewable Energy Laboratory

[2] *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006,* U.S. Department of Energy, Energy Efficiency and Renewable Energy, May 2007, page 20.

[3] "The Costs and Impacts of Intermittence: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity 16network, March 2006.

Integration is a term used in describing the economic impact wind has on a utility because of variability and uncertainty. Wind integration can lead to additional utility costs because additional generation capacity that is controllable is added to manage the incremental variability of wind. The uncertainty is attributed to operations planning required to accommodate wind. Utilities purchase regulatory reserves to balance out the variability of wind. The Federal Energy Regulatory Commission (FERC) sets generation integration rules that require a utility to balance supply and demand.

NorthWestern Energy in a July 2006 presentation to the Northwest Power and Conservation Council identified wind integration issues including: within-hour regulation issues, forecast issues, forced outage notification issues, increased regulation cost, and increased penetration levels for wind generation. Limited resource availability for regulation services and concern that present regulation resources may not be available in the future due to increased penetration of wind in other control areas also were raised.[4] In addition, transmission issues relative to load following services when purchased outside the control area were pointed out by NorthWestern. NorthWestern Energy is involved in a wind integration study now underway that is expected to address these issues in more depth.

To date, NorthWestern Energy has encountered some challenges in integrating the 135-MW Judith Gap Wind farm which came online in late 2005. Judith Gap provides between 7% and 8% of the electricity NorthWestern needs to serve customers. For example, in April 2006, the Western Electricity Coordinating Council notified NorthWestern that its transmission system may have fallen 3% short of minimum control performance standards of 90%.The lapse did not bring sanctions, but is illustrative of some of the difficulty associated with managing the ups and downs of wind -- particularly when it is new to a system. NorthWestern added a seconded regulating resource from Avista to adjust.

NorthWestern Energy has reported a wind integration cost (ancillary) of $6.75 MWh for the Judith Gap project in 2006. The value does not include the cost of operation of a gas-fired plant that is solely attributable to wind integration. The control areas used for its estimate includes wind penetration at 8.7% with purchases made at market-based rates. That contract, however, has expired. Under a new contract, the estimated integration cost for Judith Gap is estimated to more than double.

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[4] NorthWestern Energy Wind Integration, Northwest Power and Conservation Council Meeting, PowerPoint presentation, July 11, 2006.

With the approval of House Bill 25 by the 2007 Montana Legislature, NorthWestern also now has the ability to build or acquire its own generation assets. NorthWestern has discussed building a natural gas plant, which could, in part, provide some firming power for wind projects in NorthWestern's service area.

Northwest Wind Integration Action Plan

The Northwest Wind Integration Action Plan, completed in March 2007, included Montana participants and utilities that provide services in Montana. Bill Drummond with Western Montana Electric Generation & Transmission and Public Service Commission Chairman Greg Jergeson were members of the committee. A technical work group also included Montana participants. The report includes 16 action plan items.

In November, each ETIC member received a copy of the action plan, which outlined five distinct policy findings and conclusions.

1. There are no fundamental technical barriers to operating 6,000 megawatts of wind in the Pacific Northwest. "The cost of wind integration starts low, particularly when integrating with a hydropower system that has substantial flexibility, and then rises as increasing amounts of wind are added."[5]

2. Wind energy is providing value to Northwest electricity consumers, but the Northwest will still need other resources to meet peak loads.

3. In the short term there is available transmission capacity to integrate additional wind resources -- but this is not expected to last for long. The transmission capacity currently available is expected to support development through 2009. "New transmission will be needed to support growing loads and resource additions and can help open up new areas for wind development, helping to diversify wind production. This diversity helps smooth variability and therefore lowers the cost of wind integration."[6]

4. The major portion of wind integration costs are due to the need for additional flexibility resources to balance loads and resources in real time in order to accommodate wind variability. "Control area operators must have sufficient flexible

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[5] "Northwest Wind Integration Action Plan," Policy Steering Committee, letter from Tom Karier and Stephen Wright, co-chairs of the Policy Steering Committee, March 2007.

[6] Ibid.

generating capacity or load management options available to accommodate load and wind variability to ensure that reliable service will be maintained."[7]

5. The report then outlines steps that can be taken to increase integration capability and to lower integration costs:

a. develop more cooperation between regional utilities;

b. develop markets that reward utilities that market surplus flexibility;

c. make more low-cost flexibility available; and

d. develop and apply new flexibility technologies.

Strategies and technology that make better use of existing transmission lines, like voluntary economic redispatch, may enable projects to come on, despite a lack of new transmission. Rate provisions and current tariffs also deserve review, according to the report. "Cost recovery and allocation is a threshold issue for each control area and there are diverse opinions about the point at which these costs warrant developing a new tariff, and how that tariff should be designed and applied."[8]

The report concludes that the cost of wind integration is dependent on (1) the size of the area where services are procured in relation to the amount of wind integrated into a system; (2) changes in wind output at sites and generation; (3) flexibility in the power system; and (4) access to "robust" markets.[9] As noted above, these are all points that NorthWestern Energy has flagged as issues that must be addressed in adding wind to their service area.

Utility Integration Plans

Bonneville Power Administration (BPA), Avista, Puget Sound Energy, PacifiCorp, and Idaho Power have all completed wind integration studies. Some of the studies detailed within-hour and hour-to-hour costs of integrating wind energy. However, the Northwest integration action plan notes that there continues to be debate about cost figures and methodologies that are used in trying to determine cost. Preliminary wind integration costs from the initial utility studies show wind penetration at 10% for Avista resulting in a cost of $6.99 MWh; $9.75 for Idaho Power; and $3.19 for PacifiCorp.

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[7] Ibid.

[8] *Northwest Wind Integration Action Plan,* March 2007, page 12.

[9] *Ibid*, page 10.

NorthWestern Energy is in the process of participating in a wind integration study with the assistance of Phoenix Engineering, a wind engineering firm with offices in Alberta, Canada and Texas. The $110,000 wind integration study currently underway in Montana covers NorthWestern Energy's service area. The Governor's Economic Development Office, NorthWestern Energy, and Montana Alberta Tie Line are contributing about $25,000 each toward the study, which is being completed by Phoenix Engineering as noted above. The Western Area Power Administration and eight wind developers also are contributing to the study.

The study should be complete in the spring, and ETIC members will receive copies as well as a presentation on the findings in that study. The study should include findings related to the most cost effective way to integrate wind specific to Montana's transmission system.

Idaho Power in October 2007 released a report outlining the operational impacts of integrating wind into Idaho Power's existing portfolio. Idaho Power works in a 24,000-square-mile area in southern Idaho and eastern Oregon, providing power to about 440,400 customers. The original report in February 2007 showed an integration cost of $10.72 per MWh, but that was revised based on updated modeling to $7.92 per MWh. After completing the first report in February, the Idaho Public Utilities Commission asked Idaho Power to hold a public workshop and explain its methodology. Following additional workshops, Idaho Power incorporated multiple changes to its approach for calculating regulating reserves for wind. The report concludes, "One thing is for certain -- the cost of wind integration will change over time. Regional wind integration efforts, improvements in wind forecasting, regulatory changes and actual 'hands-on' experience will all have an impact on the cost of integrating wind energy."[10]

In 2005 the Minnesota Legislature passed legislation (S.F. 1368) requiring the Public Utilities Commission order utilities to participate in a wind integration study. All regulated electric utilities jointly contracted with an independent firm selected by the commission to conduct the study. The study outlined the impacts on reliability and costs associated with increasing wind capacity to 20% of Minnesota retail electric energy sales by the year 2020. The study also identified options for utilities to use to manage the intermittent nature of wind energy.

The commission administrator managed the study process and appointed stakeholders charged with reviewing the study's proposed methods and assumptions. With the completion of the study, and a review by the Commerce Commissioner, utilities were required to incorporate the study's findings into their utility resource plans. EnerNex

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[10] *Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio,* October 2007, page 27.

Corporation and WindLogics completed the study and found that the total integration cost for up to 25% wind energy delivered to all Minnesota customers would be less than one-half cent per kWh of wind generation.

Renewable Portfolio Standards

Because these types of polices have been operating for a short time, there is a lack of information on the costs and benefits related to "Renewable Portfolio Standards." In Montana the standards require public utilities and competitive electricity suppliers to procure a minimum of 5% of the retail sales from renewable resources through 2009, 10% between 2010 and 2014, and 15% starting in 2015. Cooperative utilities are responsible for implementing their own renewable standards.

The Energy Analysis Department at the Lawrence Berkeley National Laboratory has conducted some research in this arena. Its findings show that in markets where Renewable Energy Certificates, better known as Green Tags, set above-market cost, 2006 rate impacts were estimated to be at most 0.1% to 1.1%. In contract markets, like Montana, where bundled contracts dominate the market, portfolio standards may be providing savings or "at worst modest rate increase," according to the report.[11] In a presentation to the National Conference of State Legislatures in June 2007, Ryan Wiser with the Lawrence Berkeley National Laboratory provided the following:

Advantages and Disadvantages of a Renewable Portfolio Standard	
Advantages	Disadvantages
Can ensure known quantity of renewable energy	Complexity can make it difficult to design well
Can lower cost of achieving target by giving private market flexibility	Less flexible in offering targeted support to specific sources, or ensuring diversity
Competitively neutral if applied to all load-serving entities	Cost impacts not known with precision in advance
Relatively low administrative costs and burdens	Questions over whether RPS policies will necessarily lead to long-term contracts
Can be applied in restructured and regulated markets	Operating experience is limited

Source: Environmental Energy Technologies Division, Energy Analysis Department

[11] *State Policy Update: A Review of Effective Wind Power Incentives*, Ryan Wiser, Lawrence Berkeley National Laboratory, Midwestern Wind Policy Institute, June 2007.

Wind to market

Transmission issues

In the last 20 years, the cost of wind power has dropped by about 90%, according to the American Wind Energy Association (AWEA). However, the factors that determine the costs of wind power continue to change in a market that is often described as "maturing."

"Although the U.S. is well positioned to become a global leader in wind energy, one of the greatest impediments to wind development in the United States could be transmission policy."[12] FERC has jurisdiction over transmission pricing. They set the rates that transmission owners can charge and pass on to customers. In Montana, the Public Service Commission (PSC) regulates distribution costs for NorthWestern Energy and Montana-Dakota Utilities. Cooperative's elected governing boards set distribution costs for members.

Title 69, chapter 8, part 4, MCA requires nondiscriminatory access to a public utility's transmission and distribution facilities. Public utilities are required to file tariffs for transmission and distribution services regulated by FERC and the PSC.

Transmission policies currently address ramp rates, how quickly a generation facility can increase or decrease energy output, at traditional power plants, like coal operations. However, most transmission policies are based on generators controlling and predicting generation levels. Wind is an intermittent resource, and obviously wind generators can't predict production.

AWEA raises concerns about transmission policies and tariffs that allocate access to transmission lines based on time of market entry or demonstrate a preference for an existing resource. The AWEA sets its five highest transmission policy priorities as:

(1) allocation of embedded costs of transmission facilities;

(2) schedule deviation penalties in the creation of real-time balancing markets;

(3) the elimination of rate pancaking,

(4) the equitable allocation of congested capacity among competing users; and

(5) the nondiscriminatory interconnection of new generation facilities.

FERC's role in transmission also merits additional discussion. FERC asserts control over all new interconnections, the amount of transmission capacity available as a result of transmission planning, and transmission pricing policy. "Transmission scheduling

[12] *Fair Transmission Access For Wind: A Brief Discussion of Priority Issues,* American Wind Energy Association, page 2.

methods have a significant impact on wind integration."[13] In areas that operate under Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), generators are allowed to sell into a large regional pool to serve loads. This makes transmission rights a financial venture, eliminating the need for fixed physical advanced scheduling. Outside of RTOs and ISOs (like NorthWestern Energy's service area), physical transmission rights are guided by FERC. "FERC has encouraged the creation of RTOs to increase scheduling flexibility, eliminate the need to pay multiple or 'pancaked' rates across each service territory, and broaden markets."[14] Five western states, including NorthWestern Energy, are setting up the Northern Tier Transmission Group. It will not be an RTO but is expected to improve transmission planning. BPA is part of the Columbia Grid planning group.

FERC in early 2007 issued Order 890, which furthers the regional approach to transmission planning. The approach requires public utility transmission providers to participate in open transmission planning at the local and regional level. With the order, FERC has said it hopes to see more coordination between neighboring transmission providers and interconnected services, state regulators, and stakeholders. Order 890 also addresses energy and generator imbalances. Prior to the rule, imbalance penalties varied. With the new rule, imbalance penalties must be guided by three principles:

1. Charges must be based on incremental costs or a multiple;
2. Charges must provide an incentive for accurate scheduling; and
3. Provisions must account for the inability of intermittent resources, like wind, to schedule in advance.

Order 890 offers a tiered set of energy imbalances that increase as deviations increase and likewise for decreases. Under 890, however, transmission providers are not required to offer planning redispatch or conditional firm service, if it negatively impacts reliability. Transmission customers that will financially support new transmission facilities can receive conditional firm services and planning redispatch as a short term solution until the new transmission facilities are built. For those who aren't financially involved, planning redispatch and firming can be limited.

[13] "Wind Energy Delivery Issues," by Richard Piwko, Dale Osborn, Robert Gramlich, Gary Jordan, David Hawkins, and Kevin Porter, *IEEE Power & Energy Magazine*, November/December 2005, page 53.

[14] Ibid.

Montana's transmission lines

Montana's strongest interconnections with other regions are two 500 kV lines from Colstrip to Spokane, a 500 kV line and a 230 kV line west of Hot Springs, interconnections from Yellowtail Dam south to Wyoming, ties to the east at Miles City and Fort Peck, and a 161 kV line and a 230 kV line that runs south from Anaconda and Garrison into Idaho.[15]

Montana's transmission system is part of the Western Interconnection Transmission System, and because transmission lines cross state boundaries, the federal government, through FERC, has primary regulatory jurisdiction. That jurisdiction centers around wholesale rate setting and siting issues if state efforts at interstate transmission siting are not complete within a year. Other federal agencies, such as the Bureau of Land Management and the U.S. Forest Service, have a role if transmission lines cross those federal lands. The Department of Energy plays a role in coordinating and reviewing projects. Montana regulates transmission siting through the Montana Major Facility Siting Act, and that requires certain proposed transmission projects to go through a review before construction.

While utilities like NorthWestern Energy and BPA continue to build and upgrade transmission, publicly traded private companies also are entering the mix. Companies are considering constructing new independent, nonutility transmission lines in Montana. When these "merchant lines" are built, the company building the line does not generate its own electricity but sells contracts or rights to transport electricity on the lines. Utilities that own transmission lines also can propose projects in response to requests for new services from power marketers and independent generation developers. A mix of these "merchant lines," federal projects, and utility-driven efforts are underway throughout Montana.

Montana Transmission projects

❶ Montana Alberta Tie Ltd.

Calgary-based Montana Alberta Tie Ltd. is proposing a 203-mile-long transmission line that ties into the Canadian grid at Lethbridge, Alberta, and the U.S. grid at Great Falls. Three wind power developers have signed up to use the line, and the overhead line could bring 600 megawatts of wind online.

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[15] *Understanding Energy in Montana: A Guide to Electricity, Natural Gas, Coal, and Petroleum Produced in Montana,* DEQ report to the Environmental Quality Council, October 2004.

❷ Mountain States Transmission Intertie

NorthWestern Energy intends to build and operate a new 350- to 390-mile, 500kV line between southwestern Montana and southeastern Idaho. The line will relieve congestion on the existing line, which was identified as a problem in a 2006 study conducted by the Department of Energy and in an earlier Rocky Mountain Area Transmission Study. It also will assist in meeting the growing demand for electricity in the region and strengthen the integrated network, according to NorthWestern.

❸ Northern Lights

TransCanada's Northern Lights Transmission Co. has said it intends to build a 1,100-mile, 500 kV transmission line from Townsend to Idaho to Nevada and on to the Southwest. The line could be capable of moving as much as 3,500 megawatts of power.[16]

❹ WAPA Havre to Rainbow Upgrade

The Western Area Power Administration plans to rebuild its Havre to Rainbow Dam 161 kV transmission line between the Havre substation and the Rainbow Great Falls substation.

❺ BPA Libby to Troy Upgrade

BPA has proposed a rebuild of a 17-mile stretch of its 115-kV line that runs between Libby and Bonners Ferry. The Libby (Flathead Electric Cooperative's substation) to Troy section of the line is in declining condition, with many of the wood poles in need of immediate replacement.

❻ Increases from Montana to the Northwest

BPA, NorthWestern Energy, and Avista are conducting detailed engineering studies to confirm a transmission plan to integrate about 1,000 megawatts of new energy to be transferred from Montana to the Northwest. Those detailed studies are nearly complete and could outline a plan of service to potentially build a transmission line.

[16] Montana Gov. Brian Schweitzer, comments before the U.S. Senate Committee on Finance, February 2007.

Completion of the studies enables the transmission owners to offer agreements that allow environmental work and preliminary design elements to proceed. While the full capability of the line may not need to be subscribed to up-front, anchor tenants would be needed to provide sufficient revenues to enable such a project to move forward.

Tax incentives and additional services

A federal production tax credit for wind energy, first adopted in 1992 has been a driver for a number of wind developments. The tax credit, which has sunset several times and been reestablished, is a key financial incentive, and because of what is termed its "on-again, off-again" status, wind developers are often left to deal with an uncertain future, according to the AWEA. The tax credit is set to expire again in December 2008. It currently provides a 1.9-cents/kWh benefit for the first 10 years of a renewable energy facility's operation.

Montana has implemented tax incentives for renewable energy projects, including wind. A property tax abatement of 50% of the taxable value during the first 5 years after a construction permit is issued is allowed under Title 15, chapter 24, part 14, MCA.

House Bill 3, approved during the May 2007 Special Session, also includes incentives for transmission lines -- particularly lines that tie into renewable projects, like wind. The "Jobs and Energy Development Incentives Act," provides the following tax incentives for transmission lines:

❶ High-voltage direct-current converter stations that direct power to two different regional power grids are taxed at 2.25% and considered class sixteen property.

❷ Land that is within 660 feet on either side of the midpoint of a transmission line right-of-way or easement beginning after December 31, 2007 is exempt from property taxes. An owner or operation of the line must apply for the exemption, and there are limits on where the exemption is allowed.

❸ High-voltage direct-current transmission lines and associated equipment and structures, other than those that direct power to two different regional grids, that are certified under the Montana Major Facility Siting Act are class fourteen property taxed at 3% of market value. The converter station must be located in Montana east of the continental divide and be constructed after June 1, 2007. Those lines also must provide access to energy markets for Montana generation facilities constructed after June 1, 2007. The facilities include wind, biodiesel, biomass, coal gasification, ethanol, geothermal, integrated gasification combined cycle, renewable energy manufacturing, and natural gas combined cycle. The portion of an alternating current transmission line and associated equipment and structures that contract for electricity generated by the above facilities built after June 1, 2007 also is considered class fourteen. All property of electric transmission lines that originate at the above listed facilities, with at least 90% of the electricity carried by the line originating at the facilities and terminating at an existing line also qualify.

During the 2007 May Special Session, legislators also approved House Bill 2 that included funding for the recently created Energy Infrastructure Promotion and Development Division within the Department of Commerce. The division is working with wind developers as well as transmission developers.

Conclusions

Wind integration costs can be driven by the market and flexibility available to a utility. Utilities operating in control areas with limited flexibility for managing loads face wind integration costs that are largely a function of market prices. Another factor that merits consideration is the role of FERC, which has primary regulatory jurisdiction over transmission. FERC has made regulatory developments, such as a proposal to change energy imbalance penalties, to better accommodate wind.

Wind integration and the necessity of additional transmission for future wind generation are both worthy of discussion. This information is provided to assist the ETIC in contemplating both the technical issues and commercial implications of integrating wind into Montana's electricity supply system. When the integration study underway in NorthWestern Energy's service area is completed, additional information on the costs/benefits of wind power will be available on a more local level. The findings of that report will be attached to this summary and provided to the ETIC for additional discussion.

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