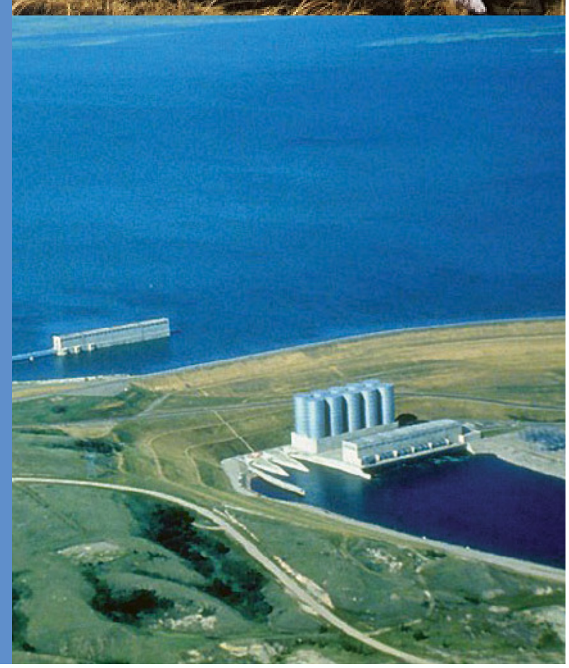
FINAL REPORT

June 2, 2009

WIND *and* HYDROPOWER

FEASIBILITY STUDY

For Section 2606 of the
Energy Policy Act of 1992,
as amended by Section 503(a)
of the Energy Policy Act of 2005



Stanley Consultants INC.

Western AREA POWER ADMINISTRATION

DEPARTMENT OF ENERGY UNITED STATES OF AMERICA

Section 2606 of the Energy Policy Act of 1992, as amended by Section 503(a) of the Energy Policy Act of 2005**. Wind and Hydropower Feasibility Study**

(a) STUDY--The Secretary of Energy, in coordination with the Secretary of the Army and the Secretary (of the Interior), shall conduct a study of the cost and feasibility of developing a demonstration project that uses wind energy generated by Indian tribes and hydropower generated by the Army Corps of Engineers on the Missouri River to supply firming power to the Western Area Power Administration.

(b) SCOPE OF STUDY--The study shall--

(1) determine the economic and engineering feasibility of blending wind energy and hydropower generated from the Missouri River dams operated by the Army Corps of Engineers, including an assessment of the costs and benefits of blending wind energy and hydropower compared to current sources used for firming power to the Western Area Power Administration;

(2) review historical and projected requirements for, patterns of availability and use of, and reasons for historical patterns concerning the availability of firming power;

(3) assess the wind energy resource potential on tribal land and projected cost savings through a blend of wind and hydropower over a 30-year period;

(4) determine the seasonal capacity needs and associated transmission upgrades for integration of tribal wind generation and identify costs associated with these activities;

(5) include an independent tribal engineer and a Western Area Power Administration customer representative as study team members; and

(6) incorporate, to the extent appropriate, the results of the Dakotas Wind Transmission study prepared by the Western Area Power Administration.

(c) REPORT--Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Secretary of Energy, the Secretary (of the Interior) and the Secretary of the Army shall submit to Congress a report that describes the results of the study, including--

(1) an analysis and comparison of the potential energy cost or benefits to the customers of the Western Area Power Administration through the use of combined wind and hydropower

(2) an economic and engineering evaluation of whether a combined wind and hydropower system can reduce reservoir fluctuation, enhance efficient and reliable energy production, and provide Missouri River management flexibility

(3) if found feasible, recommendations for a demonstration project to be carried out by the Western Area Power Administration, in partnership with an Indian tribal government or tribal energy resource development organization, and Western Area Power Administration customers to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to the Western Area Power Administration

(4) an identification of--

A) the economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership

B) the manner in which a Federal-tribal-customer partnership could contribute to the energy security of the United States

Preface

The purpose of this report is to address the mandates outlined by Section 2606 of the Energy Policy Act of 1992, as amended by Section 503(a) of the Energy Policy Act of 2005 for the Department of Energy. The report was conducted under the direction of Stanley Consultants, Inc., under contract with Western Area Power Administration. Ventyx Energy, 3TIER and EnerNex Corporation provided important contributions to this document.

The Project Team contributed significant direction to the study efforts through team meetings, sub-team review sessions and review of technical components during the course of the project. Their participation in the project is appreciated.

Mr. James L. Haigh
Western Area Power Administration
Watertown Operations Office

Ms. Jody Farhat, P.E.
Power Production Team Leader
Missouri River Basin Water
Management Division
Northwestern Division, Corps of
Engineers

Mr. Trevor McDonald, E.E
U.S. Army Corps of Engineers
Big Bend Project Office

Mr. Karl A. Wunderlich, Ph.D.
U.S. Bureau of Reclamation
Power Resources Office

Ms. Paulette Schaeffer
Power Operations
U.S. Bureau of Reclamation
Great Plains Regional Office

Mr. Darin Larson
Regional Hydrologist
BIA Office of Natural Resources

Mr. Scott Doig
BIA Environmental Services
Mid-West Regional Office

Mr. Brian Parsons
Project Manager, Wind Applications
National Renewable Energy Laboratory

Mr. Mike Costanti
Blackfeet Nation Representative
Principal Engineer
Matney Frantz Engineering

Mr. Thomas L. Weaver
Fort Peck Tribes Representative

Mr. Warren Mackey
Santee Sioux Nation
Santee Sioux Tribal Housing

Mr. Patrick Spears
President
Intertribal Council on Utility Policy

Mr. Vic Simmons
General Manager
Rushmore Electric Power Cooperative, Inc.

Executive Summary

This Executive Summary, and the report it references, was produced by Western Area Power Administration (Western) for the Department of Energy, as required by Section 2606 of the Energy Policy Act of 1992, as amended by Section 503(a) of the Energy Policy Act of 2005. Stanley Consultants was selected as lead consultant. Sub-consultants working on the project included Ventyx Energy, 3TIER and EnerNex Corporation. The report is the result of eighteen months of study to address the mandate set out in Section 2606. The primary directive was for the Secretary of Energy, in coordination with the Secretary of the Army and the Secretary of the Interior, to conduct a study to determine the cost and feasibility to develop a demonstration project that uses wind energy generated on Indian Tribal lands and Federal hydroelectric power generated on the Missouri River to supply firming power to Western to meet its contractual obligations.

A Project Team was formed to provide technical review on the Wind Hydro Feasibility Study. Project Team members provided the link between the project and each participating agency/member organization. Project Team members were tasked with keeping their respective groups informed as to progress and/or needs of the project. Meetings with the Project Team were held at critical points to discuss study progress and direction.

Background on Western

Western is one of four Federal power marketing administrations directed by law to market and transmit Federal power at cost-based rates to preference customers, including Federal and state agencies, rural electric cooperatives, public power districts, Native American Tribes, and municipal utilities. Power Marketing Plans, established through a public process, ensure a fair and equitable assignment of power from the project generation resources to preference customers in the marketing area. Generally, the amount of power and energy available for Western to Market is the amount of power remaining after meeting the power and energy needs of the authorized project purposes, e.g., irrigation pumping. Firm Power contracts set forth the contract rate of delivery (CROD) for each customer—the maximum amount of capacity made available to that customer. Because the amount of power available to allocate is limited and Western does not have load growth responsibility, Western's firm power customers must acquire other power resources to meet their total load obligations. The Upper Great Plains Region (UGPR) of Western markets and transmits power and energy from the Federal dams on the Missouri River under the Pick-Sloan Missouri River Program – Eastern Division Marketing Plan.   The Pick-Sloan Eastern Division Marketing Plan markets approximately 2,000 MW of power to over 250 firm power customers. The existing marketing plan markets firm power through the year 2020.

Study Design

Western's historical data was analyzed, and operations personnel interviewed, to establish realistic scenarios that would identify significant variables within the system to develop three hydro generation scenarios to characterize Western's operations in the context of costs to the system. LowHydro generation runs short of Western's firm power customers' energy allocations and requires up to 40 percent purchases, thus increasing costs to Western's customers. BaseHydro generation covers most of Western's firm power customers' energy allocations, but requires some purchases and allows some excess (surplus) sales. HighHydro generation covers Western's firm power customers' energy allocations and allows for excess (surplus) generation to be sold on the market for very favorable terms, thus minimizing Western's customers' costs.

The hydro-generation scenarios developed for this study compared favorably to the statistical approach utilized by the Army Corps of Engineers under the "Missouri River Mainstem Reservoir System Master Water Control Manual: Missouri River Basin, March 2006. The LowHydro scenario falls below the lower quartile, and the HighHydro scenario falls above the upper quartile projections for the Missouri river system's 40-year history. While the probability of occurrence for either of these scenarios is extremely low, they provide value as points of reference in estimating the cost benefit of tribal wind integration to serve Western load.

Using these hydro scenarios, a Purchase Capacity Bandwidth was established by analyzing load and generation data from Western's Data Historian. This bandwidth provides a maximum range for supplemental capacity, based on Western's historical purchases, of 0 – 333 MW. The range within the bandwidth was driven primarily by hydro generation variation experienced due to reservoir levels. Western's load allocation is consistent over time, so variation in load does not significantly impact the Purchase Capacity Bandwidth. Maximum value of the Purchase Capacity Bandwidth provided an estimate for capacity that could be purchased by Western over periods of both drought and excess runoff, without changing Western from a generation provider for load obligations to a net seller of energy. [Note, Purchase Capacity Bandwidth is not equivalent to a Wind nameplate value.] The Purchase Capacity Bandwidth was refined for use in evaluating a Tribal Wind Demonstration Project in two steps.

First, an estimate of potential tribal wind energy in Western's Upper Great Plains Region (UGPR) was developed. A Wind Demonstration Questionnaire was distributed to all 25 Native American Tribal customers in Western's UGPR. Six tribes responded indicating plans for wind plant projects and the Intertribal Council on Utility Policy provided information on eight projects; a total of 14 tribal questionnaires were received for use in the estimate. The 14 tribal projects identified in the completed questionnaires, indicated a total of 748 MW projected nameplate capacity through 2010, and more than twice that, 1748 MW, for future build-out capacity. Including wind potential for the tribes that did not meet the original deadline for completed questionnaires (assuming an average of 50 MW for those sites), the total build-out tribal nameplate wind projection for the UGPR could exceed 2600 MW nameplate, or approximately 1040 MW capacity (using a 40 percent capacity factor). This estimated wind energy capacity would be about 40 percent of the installed hydro capability for the Pick-Sloan Eastern Division in FY2005 of 2610 MW (Western Statistical Appendix System Data September 03, 2005).

Second, existing and future wind projects expected in Western's Balancing Area (Balancing Area), near term, had to be determined. Currently 158 MW of wind power exists in Western's Balancing Area, with another 265 MW of mature wind projects expected by 2011. (All wind project sizes are provided as nameplate values unless specifically indicated otherwise.) Generation from Western hydro assets is already moderated in response to large-scale wind power in the balancing area. These existing and expected wind projects not serving Western load within the balancing area are a key component of the operational impact analysis. They were a consideration in the total wind penetration analysis and ultimately will impact how much wind Western will allow in its balancing area.

Western is currently negotiating wind resources for a 5-year contract to replace lost hydro generation from the current drought. Three hundred (300) MW from this 5-year contract was assumed for this study, for a total of 723 MW of wind expected in Western's Balancing Area through 2015. Tribal wind could potentially replace the 5-year contract wind in 2015, and for purposes of the market simulation, tribal wind profiles were used to replace the 300 MW of contracted wind once that 5-year contract expired in 2016.

Third the maximum wind generating capacity Western could utilize had to be estimated based on the difference between generating capacity already engaged through 2015 and its contracted level of load, which is approximately 2,000 MW. Western operates with a legal charter that obligates it only to provide power to its contracted load, and does not authorize it to amass additional generating capacity that would make it a net seller of electricity. Taking into account the wind and hydro assets already expected in the Balancing Area as well as the maximum amount of load to serve, the maximum capacity for a Tribal Wind Demonstration Project in the near term was judged to be 50 MW. The primary factors that constrained the maximum project size reflect legal considerations of Western related to its charter and pre-existing business commitments. The technical feasibility of integrating wind with hydro in the Western Balancing Area is demonstrably higher than 50 MW given the 723 MW of wind expected in the system between 2011-2015.

Based on conditions described above, Western used a 50 MW Tribal Wind Demonstration Project to conduct the feasibility assessment for this study. This demonstration project was added to the 723 MW of wind expected to be in Western's Balancing Area in 2011, for a total of 773 MW of wind in the Balancing Area. This represents 423 MW of wind in the Balancing Area that is not being used to cover Western's load and 350 MW in the Balancing Area of wind that is being used to serve Western's load.

Total nameplate capacity for wind in Western's Balancing Area of 773 MW is a 25 percent wind capacity penetration on Western's Balancing Area (given Western's Balancing Area peak load of

3090 MW). To compare this nameplate capacity to the Purchase Capacity Bandwidth identified through analysis of historical data, maximum value of the Purchase Capacity Bandwidth had to be converted to wind nameplate capacity. Assuming a wind capacity factor in the UGPR of 40.8 percent, 333 MW would convert to 816 MW of nameplate wind. Although the 773 MW is slightly less than the wind nameplate equivalent for the Purchase Capacity Bandwidth (if all of the wind were being used to serve Western's load), for purposes near term, a 25 percent wind penetration level on the Balancing Area (773 MW of wind) was considered an optimistic goal, given operational adjustments that will be required initially. Further, these estimates do not consider wind generation facilities constructed within Western's service territory that are not serving Western load or non-Western load within Western's balancing area. Approximately 180 MW are electronically metered out of Western's balancing area thus this wind energy does not impact the operational considerations evaluated in this study.

Research Findings

Two wind scenarios were developed to test feasibility of a 50 MW Tribal Wind Demonstration Project in Western's Balancing Area. The BaseWind scenario included 723 MW of non-tribal wind expected to be in Western's Balancing Area by 2011, a wind penetration of 23 percent. The TribalWind scenario included all of the wind in the base case plus 50 MW for a Tribal Wind Demonstration Project, for a total of 773 MW or a 25 percent wind penetration.

These two wind scenarios were examined to determine constraints on the UGPR Balancing Area transmission system through load flow analysis and nodal market simulations (using PROMOD IV). Results from each of these studies revealed no significant transmission constraints as a result of the additional tribal wind.

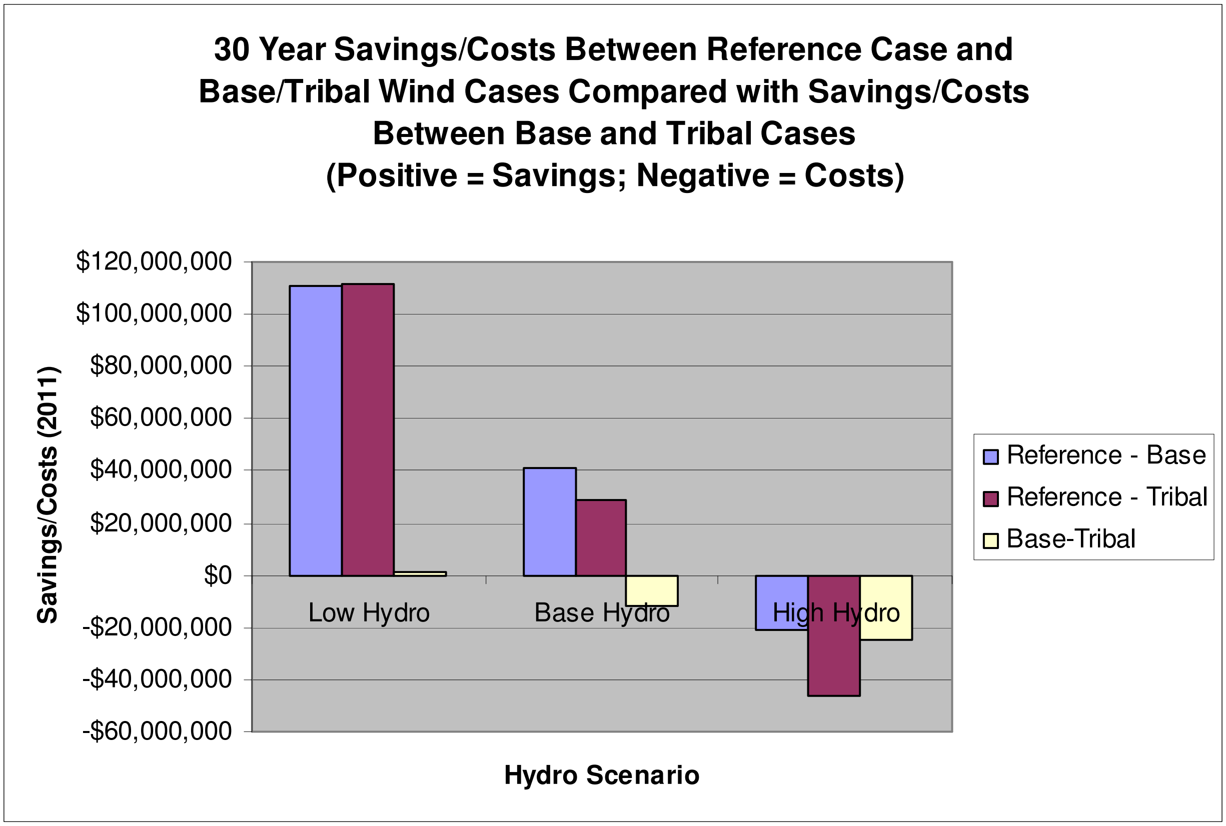
The economic impact of additional tribal wind in the Balancing Area was also analyzed. Zonal market simulations (using PROMOD IV) generated costs to Western's customers of the wind used to meet Western's load over 30 years for the six scenarios (two wind scenarios for each of the three hydro scenarios). These costs are a function of assumptions embedded in the PROMOD IV model about both technology development and market conditions outside the Western Balancing Area. A formal sensitivity analysis of those assumptions is outside the scope of this study. These market simulations included an assumption that a carbon penalty would be incurred starting in 2012 and run through the 30 years.

Net Present Values for Renewable Energy Credits (RECs) and Operation & Maintenance (O&M) expenses for transmission interconnection costs for the 50 MW of tribal wind revealed that the net value of REC and transmission O&M costs was $3.7 million in savings for Western's ratepayers over the 30-year period ($123,000 average annually) for the TribalWind case in all three hydro scenarios. This net savings depends on the assumptions used for the RECs and the cost expected for the interconnection. Since this calculation did not vary with simulated generation levels, these values provide a reference amount for consideration in the final cost evaluation.

A ReferenceWind case was included in the zonal market simulations to provide a baseline cost for current Western operations. This case included 158 MW of wind currently in the UGPR Balancing Area. Reviewing the operating costs for the ReferenceWind cases—costs Western's customers would currently experience in *PROMOD dollars*—shows a range from a low of $116 million average annual operating costs for a high hydro generating year ($3.5 billion for 30-year total) to a high of $203 million average annual operating costs for a low hydro generating year ($6.1 billion for a 30-year total, see Table 2-15). The deviation around the base hydro generating case indicates that operating costs for a low generation year are an average of $49 million annually more than a base generation year ($203 million - $154 million); a high generation year is around $38 million less annually than a base generation year ($154 million – $116 million). (All costs used in comparing cases are net present value in 2011 dollars.)

Comparing this ReferenceWind case (158 MW of wind in Balancing Area) with the BaseWind (723 MW of wind in Balancing Area) and TribalWind cases (773 MW of wind in Balancing Area) over the three hydro scenarios provides an indication of the relative costs/savings to Western customers when adding 300 MW and 350 MW of wind to cover Western load. The BaseWind (300 MW of wind serving Western load) and TribalWind cases (350 MW of wind serving Western load) saves Western's customers approximately $3.7 million dollars annually in the low hydro generation scenario ($110 million for 30 year total, see Table 2-15), and approximately $1.3 million and $1 million on average annually for the BaseWind and TribalWind cases in the BaseHydro scenario ($41 million and $29 million for 30 year totals). Cost comparison for the high generating year indicates that both the BaseWind (300 MW of wind serving Western load) and TribalWind cases (350 MW of wind serving Western load) cost Western's customers an average $706,000 and $1.5 million annually, respectively ($21 million and $46 million for 30- year total). These values suggest that adding wind up to 350 MW to serve Western load during low generation and base generation years saves Western's customers money. It also indicates that adding this amount of wind generation to Western's generation portfolio during a high hydro generation year, costs Western's customers money.. Because the probability of either the low or high hydro generation case is extremely low, these cases serve as analytic markers that indicate the cost/savings impact is non-linear across the threshold at which Western becomes a net seller.

Comparing costs between the BaseWind and TribalWind cases for the three hydro scenarios gives an indication of relative costs/savings when adding the incremental 50 MW of tribal wind to serve Western's load. These differentials show that only the low hydro generating case saves Western's customers money when adding 50 MW of tribal wind to the 300 MW already serving Western's load. Figure i shows the BaseWind minus TribalWind savings/costs compared to savings/costs incurred with each of these cases in the ReferenceWind case.



NPV Total 30 Year Costs Between Reference Case and Base/Tribal Wind Cases Compared with Savings/Costs Between Base and Tribal Cases
Figure i

These findings suggest that there may be an *economic saturation for wind energy* at 300 MW or less when this wind energy is used to meet Western's load (using the pricing assumptions in these marketing simulations). Considering this theoretical saturation point may produce an optimal economic wind integration level to meet Western's load obligations that balances the savings during a low hydro generation year with the costs incurred during a high hydro generation year. Findings also indicate that the cost of a 50 MW Tribal Wind Demonstration Project may depend on how much wind is already being used to serve Western's load when the 50 MW is added. For example, the conclusion of the anticipated 5-year 300 MW contract through 2015 would present an opportunity to add up to 350 MW of Tribal wind, with an undetermined economic saturation point between 300 MW and 350 MW based on the assumptions in this study. Further work will be needed that focuses on determining conditions that influence economic saturation of wind integration.

Members of the Project Team also requested a case with zero carbon penalties, BaseHydro/BaseWind with Zero Carbon. This case was compared with the BaseHydro/ BaseWind case (all other cases were run with carbon penalties assumptions). The simulated results showed a cost savings to Western's ratepayers of $40 million annually ($1.2 billion for

30-year total see Table 2-18) when CO2 legislation is assumed. The cost savings related to the carbon penalty assumption is expected since Western's hydro generation does not have a carbon penalty. Selling hydro generation into a carbon-penalized market would be advantageous to Western's costs, and save Western's customers when carbon-penalized resources become more expensive. This expected savings may provide some relief to Western's customers as the impacts of a carbon-penalized market are realized.

Impact of Wind Energy on Reservoir Fluctuations

In summarizing impact of wind energy on reservoir fluctuation, the Corps of Engineers (Corps) indicated in a qualitative assessment, that addition of wind generation to the hydropower system may result in changes to the pattern of generation from the Corps's projects on a real-time basis over a period of several hours to as much as several days. However, this addition is not expected to impact generation at the hydropower facilities over longer time-frames. This is due to the Corps's requirements to move water for other project purposes. Addition of wind generation is also not expected to result in reduced reservoir fluctuations or provide additional flexibility in the management of the reservoir system under the current Master Manual. In fact, addition of wind generation could complicate the management of the Missouri River Mainstem Reservoir System.

Evaluation of Joining a Nearby Independent System Operator

Concurrent with the Wind and Hydropower Feasibility Study (WHFS), Western is engaged in evaluating the possibility of joining one of the nearby Independent System Operators (ISO)—MidWest ISO or Southwest Power Pool. Although results of that study have not yet been released, generally the increased load in a larger balancing area could reduce the impact of the wind variability on operations, thus requiring less incremental operating reserves. [Note: Results from that study will be released in a separate document. None of the quantitative results from that study have been incorporated into this report.]

Recommendations

The initial Purchase Capacity Bandwidth projected from Western's historical data suggested that up to 333 MW (816 MW wind nameplate) of capacity could be used to meet Western's long term load obligations. However, findings from the market simulations indicate that wind energy with nameplate capacity of 350 MW as compared to a wind energy nameplate capacity of 300 MW shows a net increase in expense to Western's ratepayers over a 30 year period under the assumptions and scenarios that were identified as the scope of the study effort.

The economic analysis conducted for this study revealed the need for additional refinement of the MW bandwidth at which wind energy is most beneficial to Western's ratepayers. Further, since no studies were run between zero and 300MW to determine an ideal name plate capacity of wind to serve Western load obligations, no blanket economic assumptions can be made below the 300 MW level. Only by running additional studies can Western fully assess the size, benefits, and risks associated with integration of wind to serve Western load obligations on a long term basis below the 300 MW level.

In summary, further refinement of this economic saturation point for wind must be performed prior to determining an ideal nameplate capacity of wind to serve Western load obligations. Therefore, Western recommends conducting additional incremental studies between the 0 to

300 MW range including an assessment of carbon legislation impacts and updating the studies for actual wind development that will have occurred within Western's Balancing Area. Western recommends non-reimbursable funds be made available to complete the refinement of the economic saturation point for wind.

The WHFS workplan was developed under the premise that a Tribal wind energy demonstration project could be integrated into UGPR under existing generating agency operating authorities and operational practices. Additional study needs to be conducted to determine the point at which existing limitations are exceeded due to integrating larger amounts of variable wind energy. Additional study is also necessary to quantitatively assess the costs of increased wind integration on Corps and Reclamation facilities, including the 723 MW of wind already anticipated by 2011 irregardless of a Tribal Wind Demonstration Project.

These costs may include, but are not limited to:

- Increased unit cycling (stops and starts),
- Increased range and variation in the output of generators,
- Increased wear on electrical and mechanical equipment,
- More frequent replacement of capital equipment and attendant costs,
- Increased plant operation and maintenance (O&M) costs.

As Western considered the recommendation for a demonstration project, several key influences were assumed:

- The specified objectives contained in the Section 2606 legislation.
- Western's legislated role as a supplemental energy provider with no load growth responsibility.
- The impact to hydro-generation resource regulation capacity resulting from development of wind energy generation facilities within Western's control area serving non-Western load.
- The physical impacts to hydro-generation plant facilities resulting from fast regulation imposed by all wind generation facilities in the balancing area,
- The conclusions reached in this study do not limit wind development in the region constructed to serve load outside of Western's balancing area.

As discussed above, additional study work is needed. However, Western believes a demonstration project recommendation can be made under certain limitations. Western's primary concern with a demonstration project is the economic risk to its ratepayers indicated by costs calculated in extremely unlikely High Hydro case. Western believes the following limitations are necessary to mitigate this economic risk:

1. A demonstration project be of no more than 50 MW nameplate capacity in size if authorized and funded prior to 2015, and less than 350 MW in size if authorized and funded after 2015; and

2. Any costs of the demonstration project beyond what Western would have normally paid for like energy should not be borne by Western's ratepayers.

Public Comment Period

A draft of the WHFS was released on December 15, 2008 for a 60 day public comment period closing February 13, 2009. A public meeting on the study and report was held in Rapid City, South Dakota on January 13, 2009. A transcript of the public comment meeting is available in Appendix K. Written comments on the study and report were received from:

- Yankton Sioux Tribe General Council Resolution No. 2009-008
- Harvest Initiative, Inc.
- Missouri River Energy Services
- Fort Peck Tribes Assiniboine & Sioux
- Xtreme Power Solutions
- Mid-West Electric Consumers Association
- Intertribal Council on Utility Policy

These comments and Western's response are also in Appendix K. There were no substantive changes made to the report due to the comments submitted during the public comment period.

Table of Contents

TABLES

FIGURES

APPENDICES

Please be advised that Appendix F: Transmission Planning Documents may contain information that is for the exclusive use of the named recipient(s). No personnel whose primary job function is in a Power Merchant organization may view or have access to such information as required by FERC Standards and Codes of Conduct, Critical Energy Infrastructure Information (CEII), and/or state Codes of Conduct. In addition, persons authorized to receive this information shall take precautions not to disclose or be conduits of any non-public transmission information to any party's marketing and Sales or Energy Affiliate personnel. If you have received this appendix in error, please notify the sender immediately, and destroy this appendix and any attachments.

Section 1

Introduction and Background

Introduction

The Energy Policy Act of 2005, Section 2606, required a Wind and Hydropower Feasibility Study (WHFS). The primary directive was for the Secretary of Energy, in coordination with the Secretary of the Army and the Secretary of the Interior, to conduct a study to determine the "cost and feasibility to develop a demonstration project that uses wind energy generated on Indian Tribal lands and Federal hydroelectric power generated on the Missouri River to supply firming power to Western to meet its contractual obligations."

As of 2007, the Missouri River Mainstem, which is the portion of the river basin associated with the Pick-Sloan Missouri Basin Program—Eastern Division (P-SMBP-ED), was in its eighth year of drought. Periods of low water runoff trigger periods of low hydro generation, which in turn, require power purchases by Western Area Power Administration's (Western) Upper Great Plains Region (UGPR) to supply energy obligations to its customers. These market purchases almost always occur at rates higher than Western's established composite hydro rates. Although Western purchases up to 40 percent of its energy needs in a low generation year, up to 5 percent of Western's UGPR energy is also purchased in a high hydro-generation year.

Historically, cost-based rates of hydro-generated power have been very low. However, as the quantity of power purchases at market rates increase, rates paid by Western's customers have also increased. Composite rates for the Eastern Division have more than doubled since 1992 from 11.56 mills/kWh to 24.78 mills/kWh in 2008 (Pick-Sloan Missouri Basin Program Firm Power Rate History 7/22/08). This study looks to "supplement" the hydro generation shortfall with tribal wind energy, and determine whether integrating this tribal wind energy creates cost advantages over current market purchases. [The word "blend" is used in the legislation, but in the context of this study it is understood to mean "provide energy to supplement."]

Western's UGPR sells power in Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota. Within this region, Western has 25 Native American Tribal customers. Tribal lands are geographically dispersed throughout the region. This region is recognized as having one of the most promising wind resource potentials in the United States (US DOE, 2008). Potential for this wind energy generation has spawned several wind integration studies to begin the process of harnessing this Upper Great Plains wind energy (e.g., ABB, 2005; EnerNex, 2006).

Native American Tribes within the UGPR have also begun developing wind production on their lands. The Intertribal Council on Utility Policy (ICOUP) was formed in 1994 with a goal of building out wind power potential of the Great Plains. With assistance of ICOUP, the Rosebud Tribe installed the first Native American utility-scale wind turbine on the Rosebud Sioux Indian Reservation in South Dakota. Similarly, in 2006, the Mandan, Hidatsa and Arikara Nations commissioned their first 66 kW wind turbine on the Fort Berthold Indian Reservation in North Dakota. This project received a grant from the Department of Energy's Tribal Energy Program, which is designed to support renewable energy development on tribal lands. These projects have started with single turbine projects to develop experience for larger-scale projects. The Wind Hydro Feasibility Study (WHFS) is designed to test the feasibility of a Tribal Wind Demonstration Project that might lead to a Federal-Tribal-Customer partnership to supply wind energy to Western.

Objectives of the WHFS are outlined in Section 2606 of the EPAct 2005. Legislation is outlined in Table 1-1.

Table 1-1

EPAct 2005 Section 2606. Wind and Hydropower Feasibility Study

(a) *STUDY--The Secretary of Energy, in coordination with the Secretary of the Army and the Secretary (of the Interior), shall conduct a study of the cost and feasibility of developing a demonstration project that uses wind energy generated by Indian tribes and hydropower generated by the Army Corps of Engineers on the Missouri River to supply firming power to the Western Area Power Administration.*
(b) *SCOPE OF STUDY--The study shall--*
(1) *determine the economic and engineering feasibility of blending wind energy and hydropower generated from the Missouri River dams operated by the Army Corps of Engineers, including an assessment of the costs and benefits of blending wind energy and hydropower compared to current sources used for firming power to the Western Area Power Administration;*
(2) *review historical and projected requirements for, patterns of availability and use of, and reasons for historical patterns concerning the availability of firming power;*
(3) *assess the wind energy resource potential on tribal land and projected cost savings through a blend of wind and hydropower over a 30-year period;*
(4) *determine the seasonal capacity needs and associated transmission upgrades for integration of tribal wind generation and identify costs associated with these activities;*
(5) *include an independent tribal engineer and a Western Area Power Administration customer representative as study team members; and*
(6) *incorporate, to the extent appropriate, the results of the Dakotas Wind Transmission study prepared by the Western Area Power Administration.*
(c) *REPORT--Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Secretary of Energy, the Secretary (of the Interior) and the Secretary of the Army shall submit to Congress a report that describes the results of the study, including--*
(1) *an analysis and comparison of the potential energy cost or benefits to the customers of the Western Area Power Administration through the use of combined wind and hydropower*
(2) *an economic and engineering evaluation of whether a combined wind and hydropower system can reduce reservoir fluctuation, enhance efficient and reliable energy production, and provide Missouri River management flexibility*
(3) *if found feasible, recommendations for a demonstration project to be carried out by the Western Area Power Administration, in partnership with an Indian tribal government or tribal energy resource development organization, and Western Area Power Administration customers to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to the Western Area Power Administration*
(4) an identification of--
A) *the economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership*
B) *the manner in which a Federal-tribal-customer partnership could contribute to the energy security of the United States*

This feasibility study is very similar to many of the recent wind integration studies that have been conducted on the fertile wind regions of the country. As with other integration studies, the results obtained are highly dependent on the input assumptions and analysis methods used in the study. The research design determines these important guidelines. The research design adopted for the WHFS was to determine a reasonable range of historical energy purchases that Western has experienced over the last ten years, and from that range, allocate a nameplate capacity for a demonstration project for tribal wind energy. Using that demonstration project as the TribalWind test case, the research design then compared that TribalWind case with a BaseWind case to consider impacts on the transmission system ("engineering feasibility") , as well as potential costs and benefits to Western's firm power customers ("economic feasibility") over 30 years.

The study process was designed to produce results through a realistic characterization of Western's current system, and a set of reasonable assumptions that considered the uncertainties ahead in the electric utility industry. The study did not consider issues of policy, regulation, or law in the context of integrating tribal wind into Western's Balancing Area. Tribal wind energy was not given any preferential treatment, but used and valued like any other wind resource available to Western.

Stanley Consultants, Inc., was retained by Western as the lead consultant for the project. Stanley Consultants was responsible for managing the project, analyzing the historical data, conducting the transmission load flow studies, performing the economic analysis, and writing the report.

Several sub-consultants to Stanley Consultants assisted in the technical requirements to complete components required for production modeling. Ventyx was responsible for developing market simulations in their PROMOD IV (PROMOD) software package. 3TIER provided simulated wind energy data for the wind projections assumed in the scenarios. EnerNex analyzed the operating reserve requirements for the wind penetration levels outlined in the scenarios.

A Project Team was formed to provide technical review on the WHFS project. Project Team members provided the link between the project and each participating agency/member organization. Project Team members were responsible for keeping their respective groups informed as to progress and/or needs of the project. Meetings with the Project Team were held at critical points to discuss study progress and direction. Sub-team meetings were held with appropriate Project Team technical experts, as needed, to discuss specific technical aspects of the study. The Project Team also helped to incorporate the industry knowledge accumulated through traditional wind development and integration studies.

Western provided historical data and interviews with operations personnel to create realistic system characteristics. Ventyx, 3TIER and EnerNex contributed expertise to develop reasonable assumptions for market simulations. Ventyx relied on its standard, industry-accepted, set of input assumptions for base case development used in other market simulation consulting projects. Carbon penalty legislation enacted in 2012 was part of the basic assumptions. The Project Team also reviewed assumptions for market simulations. This effort culminated in a combination of factual historical information and projections drawn from marketing simulations. Pooling these findings, this report offers recommendations that address the legislative mandate outlined in Section 2606.

Marketing simulation projections, however, must be interpreted within the context of the assumptions from which they were formed. Assumptions around fuel price escalations and carbon penalty legislation, for example, are critical variables in determining projected economic results. For example, after the Project Team reviewed the assumptions, an additional case was added to look at the impact of the carbon penalty legislation. The additional case assumed no carbon legislation was enacted. Comparing the results from the cases run with no carbon penalty legislation (ZeroCarbon) with the cases assuming carbon penalty legislation was in place (WithCarbon), show the ZeroCarbon cases costs more than the WithCarbon cases (see Table 2-18). Similarly, if carbon penalties were assumed to be higher than those used in this study, the costs would change again. Recommendations in this report are based on the set of conditions outlined by the input assumptions. Therefore, findings from the market simulations must be interpreted within the framework of assumptions outlined.

To minimize misinterpretation of results, this research design relies on comparing cases with the same assumptions that change one variable (e.g., with tribal wind, without tribal wind). Given this *comparative* research design, the WHFS is not like the other wind integration studies currently being conducted. Many other wind integration studies look to define parameters of wind integration, primarily the cost of integrating wind onto the grid or the maximum wind penetration a balancing area can integrate, through a single market simulation. The WHFS uses many of the same techniques relied on in these integration studies (e.g., sub-hourly analysis, production costing simulations), but the research objective is not to determine a specific number associated with tribal wind integration.

The research objective for the WHFS is to determine whether or not to recommend a Tribal Wind Demonstration Project. This study relies on a matrix of market simulations that allows comparisons between the variables of interest to the study—specifically the amount of hydro-generation in the Balancing Area and the amount of tribal wind in the Balancing Area. The determination is based first on engineering feasibility (i.e., transmission constraints), and if feasible, the economic feasibility (i.e., costs as determined from the comparisons described above) to Western's customers. The study will provide recommendations related to a Tribal Wind Demonstration Project.

The report is divided into six sections:

- Section 1—Introduction and Background, provides an overview of the research design for the study and a basic summary of Western's system;
- Section 2—WHFS Work Plan Results, documents the analysis performed as outlined in the Work Plan;
- Section 3—Combined Wind and Hydro Impact on Reservoir Fluctuation, summarizes the Corps of Engineers' opinion on wind energy's impact on reservoir operations;
- Section 4—Benefits of Federal-Tribal-Customer Partnership identifies the impacts of a partnership for Western, Western's firm power customers, and the tribes;
- Section 5—Recommendations for a Tribal Wind Demonstration Project, outlines the recommendations drawn from the analysis; and
- Section 6—Conclusions, capstones all of the components of the report.

Background on Western Balancing Area Operations

Western is one of four Federal power marketing administrations directed by law to market and transmit Federal power at cost-based rates to preference customers, including Federal and state agencies, rural electric cooperatives, public power districts, Native American Tribes, and municipal utilities. Power Marketing Plans, established through a public process, ensure a fair and equitable assignment of power from the project generation resources to preference customers in the marketing area. Firm Power contracts set forth the contract rate of delivery (CROD) for each customer—the maximum amount of capacity made available to that customer. Some of these Firm Power contracts include a provision for returning peaking energy during off-peak periods. There are three peaking contracts currently in place with Western customers. In accordance with Pick-Sloan Eastern Division Marketing Plan, all firm Power contracts in UGPR expire in 2020.

History of Pick-Sloan Missouri Basin Program and Integrated System Partners

The Pick-Sloan Missouri Basin Program (P-SMBP) was authorized by Congress in Section 9 of the Flood Control Act of December 22, 1944, commonly referred to as the Flood Control Act of 1944. This multipurpose program provides flood control, irrigation, navigation, recreation, preservation, and enhancement of fish and wildlife, and power generation.

Power generated by the P-SMBP is administered by two regions. The Rocky Mountain Region, with a regional office in Loveland, Colorado, markets the Western Division of P-SMBP-WD. Markets include Wyoming, Western Nebraska, Colorado, and portions of Kansas. The Upper Great Plains Region (UGPR) with a regional office in Billings, Montana, markets the Eastern Division of P-SMBP-ED. The Eastern Division UGPR markets power in western Iowa, Montana east of the Continental Divide, North Dakota, South Dakota, western Minnesota, and the eastern two-thirds of Nebraska. The P-SMBP-ED power is marketed to approximately 300 firm power customers in the UGPR.

Prior to 1959, the Bureau of Reclamation (Reclamation) provided the total power supply needs to preference customers in the Pick-Sloan Missouri Basin Program—Eastern Division (P-SMBP--ED) Marketing Area from power generated at Reclamation's multi-purpose facilities and Corps projects in the region. Reclamation constructed a federal transmission system to supply power to those preference customers. Until 1964, Reclamation could meet the total projected power needs for the preference customers. After the year 1964, supplemental power suppliers began supplying power to many preference customers.

As new generation was added to the system to provide this supplemental power, transmission additions were needed. In 1963, the Joint Transmission System (JTS) was created when Reclamation and Basin Electric Power Cooperative (Basin) entered into the Missouri Basin Systems Group (MBSG) Pooling Agreement (Agreement). In 1977, Western was established and assumed the responsibility for the Reclamation-owned federal transmission system and existing contacts pursuant to Department of Energy Organizational Act. Heartland Consumers Power District (Heartland) and Missouri Basin Municipal Power Agency (MBMPA) organized in the mid-1970s, and subsequently signed the MBSG Agreement. Basin, Heartland, and MBMPA all supply supplemental power to certain preference customers, and are commonly referred to as supplemental power suppliers. The MBSG Agreement provided for joint planning and operation of some, but not all, of the transmission facilities for Western, Basin, Heartland, and MBMPA (Participants).

In the 1990s, the JTS had to be modified to recognize changes in the utility industry for deregulation and open access transmission. Those modifications resulted in formation of the Integrated System (IS) which combined the transmission facilities of Western, Basin, and Heartland. Similar to the JTS, Western was designated as the operator of the IS by Basin and Heartland, and, as such, contracts for service, bills for service, collects payments, and distributes revenues to each participant of the IS.

History of the Missouri River Basin Water Management Division

The Missouri River Basin Water Management Division (MRBWMD) of the Corps of Engineers (Corps) directs the regulation of the Missouri River Mainstem Reservoir System (System) to serve the Congressionally-authorized project purposes of flood control, navigation, hydropower generation, irrigation, water supply, water quality control, recreation, and fish and wildlife. The Missouri River Mainstem Reservoir System Master Water Control Manual (Master Manual) provides guidelines for operating the System. The Master Manual was first published in 1960 and has been revised periodically since. The most recent revision was in 2006 (http://www.nwd-mr.usace.army.mil/rcc/reports/mmanual/MasterManual.pdf). The Corps develops an Annual Operating Plan (AOP), available in January of each year, to forecast the System regulation to serve the authorized purposes under varying hydrologic conditions (http://www.nwd-mr.usace.army.mil/rcc/aop.html). Spring updates are also made to the AOP, as well as other adjustments as needed throughout the year to respond to substantial departures from expected runoff forecasts

Delivering Western's Hydro Power

The UGPR carries out Western's mission in Montana, North Dakota, South Dakota, Nebraska, Iowa, and Minnesota, delivering approximately 2000 MW of firm capacity from 8 dams (6 Corps dams and 2 Reclamation dams) and power plants of the Pick-Sloan Missouri Basin Program-Eastern Division. This power is enough to serve more than 3 million households. This hydro power is delivered through nearly 100 substations, across nearly 7,800 miles of Federal transmission lines. These lines are connected with other regional transmission systems and groups.

To keep power moving through the UGPR Balancing Area, operations in Watertown, South Dakota, determine where to deliver power based on demand in the six-state area (http://www.wapa.gov/ugp/aboutus/default.htm). The UGPR Balancing Area includes not only Western operations, but several other generators and transmission owners. The UGPR Balancing Area has recently recorded system peaks of:

- Summer-3,088 MW on July 23, 2007,
- Winter -3,090 MW on January 29, 2008.

Section 2

WHFS Work Plan Results

After the contract for the WHFS was awarded to Stanley Consultants in May 2007, the study team met in Rapid City, South Dakota, to determine how to proceed with the work. The group reviewed the key areas of the enabling legislation, the Dakotas Wind Transmission Study, other wind integration studies, the constraints on the Missouri River System, and Western's current operating conditions. The key issues for the study work plan were discussed, and Stanley Consultants was given the charge to develop a WHFS Work Plan (Work Plan) based on these discussions. The team reviewed the Work Plan, which was presented for Public Comment at a meeting in Bismark, North Dakota, on September 27, 2007. The Work Plan was finalized based on comments received during the public comment period.

Following Work Plan finalization, Stanley Consultants began work on Work Elements 1 through 5. The result from efforts on these work elements is contained in this section. Work Element 6 specified the draft and final report outline. The draft report was presented at a Public Comment meeting in Rapid City, South Dakota, on January 13, 2009. The WHFS report was finalized based on comments received during the public comment period.

Work Element 1- WHFS Work Plan

Legislative Objective: Section 2606 (b) (5) include an independent tribal engineer and a Western Area Power Administration customer representative as study team members;

Project Team

The legislation mandated that an independent tribal engineer and a Western customer representative participate on the study team. In March 2007, Western initiated contact with potential tribal, customer, and other interested parties to identify study team members. In response to these requests, three tribes and one inter-tribal organization submitted nominations for project team membership. Representatives from three UGPR customer utilities were nominated as potential study team members. In an effort to encourage project ownership, and to ensure representation of the diverse interests of the UGPR customer base, four tribal and three customer members were selected as study team members.

The Project Team was formed from the study team to provide review of the WHFS project. Project Team members provided the link between the project and each participating agency/member organization. Project Team members were responsible for keeping their respective groups informed as to progress and/or needs of the project. The Project Team members coordinated within their organizations to ensure appropriate review by various disciplines. Meetings with the Project Team were held at critical points of the study. The composition of the Project Team remained fairly constant throughout the project, although tribal participation increased late in the process as a result of growing interest in this study. At critical junctions in the project, a sub-team was called on to provide specialized technical advice - for example, to determine the need for meso-scale modeling and sub-hourly analysis. The members of the Project Team are listed in Appendix A.

Work Plan Development

The WHFS Project Team met starting in May 2007 to discuss and guide development of study scope for the WHFS project. Three primary components of the project included: 1) the physical integration of wind; 2) the operational integration of wind into Western's system; and 3) economics associated with wind integration. "Economics" was defined to include costs incurred by the project developer, Western, and its rate payers.

Legislation mandated that results from the Dakotas Wind Transmission Study (ABB, 2005) be incorporated into the project. The National Renewable Energy Laboratory (NREL) and Project Team members also provided background on how wind study methodologies and findings from other relevant studies could add value to this study.

While Section 2606 legislation provided macro objectives for this study, it was necessary to establish a consistent understanding of how the existing hydropower system and integrated transmission system operate. Initial Project Team meetings/conference calls focused on the relevant background necessary to develop Work Plan tasks suited to meeting Section 2606 objectives. The Work Plan provided sufficient structure to guide overall project execution, yet contained sufficient flexibility to ensure course corrections could be made without need for formal work plan rewrites.

The Work Plan consisted of five Work Elements representing distinct tasks that build on each other to address study requirements laid out by legislation (see Table 2-1). A full copy of the final Work Plan is included in Appendix B. Table 2-2 depicts critical questions to be answered by work elements outlined in the Work Plan. Discussions in the next sections provide a summary of work performed to address critical questions for each work element.

Table 2-1 Legislative Reference to Work Elements and Report Sections

Sec. 2606. Wind and Hydropower Feasibility Study

(a) *STUDY—The Secretary of Energy, in coordination with the Secretary of the Army and the Secretary, shall conduct a study of the cost and feasibility of developing a demonstration project that uses wind energy generated by Indian tribes and hydropower generated by the Army Corps of Engineers on the Missouri River to supply firming power to the Western Area Power Administration.*	
(b) *SCOPE OF STUDY—The study shall--*	**Work Element:**
(1) *determine the economic and engineering feasibility of blending wind energy and hydropower generated from the Missouri River dams operated by the Army Corps of Engineers, including an assessment of the costs and benefits of blending wind energy and hydropower compared to current sources used for firming power to the Western Area Power Administration;*	**WE 5**
(2) *review historical and projected requirements for, patterns of availability and use of, and reasons for historical patterns concerning the availability of firming power;*	**WE 2**
(3) *assess the wind energy resource potential on tribal land and projected cost savings through a blend of wind and hydropower over a 30-year period;*	**WE 3 and 5**
(4) *determine the seasonal capacity needs and associated transmission upgrades for integration of tribal wind generation and identify costs associated with these activities;*	**WE 2 and 4**
(5) *include an independent tribal engineer and a Western Area Power Administration customer representative as study team members; and*	**WE 1**
(6) *incorporate, to the extent appropriate, the results of the Dakotas Wind Transmission study prepared by the Western Area Power Administration.*	**WE 4**
(*c)--Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Secretary of Energy, the Secretary (of the Interior) and the Secretary of the Army shall submit to Congress a report that describes the results of the study, including--*	**Report Section:**
(1) *an analysis and comparison of the potential energy cost or benefits to the customers of the Western Area Power Administration through the use of combined wind and hydropower*	**2**
(2) *an economic and engineering evaluation of whether a combined wind and hydropower system can reduce reservoir fluctuation, enhance efficient and reliable energy production, and provide Missouri River management flexibility*	**3**
(3) *if found feasible, recommendations for a demonstration project to be carried out by the Western Area Power Administration, in partnership with an Indian tribal government or tribal energy resource development organization, and Western Area Power Administration customers to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to the Western Area Power Administration*	**5**
(4) *an identification of--*	**4**
A) *the economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership*	
B) *the manner in which a Federal-tribal-customer partnership could contribute to the energy security of the United States*	

Table 2-2 Critical Questions to be Answered in the Work Plan Elements

	Work Element 1	Work Element 2	Work Element 3	Work Element 4	Work Element 5
	WHFS Work Plan	**Analysis of Historical Western Purchase Requirements**	**Wind Project Identification**	**Transmission System Evaluation**	**Assessment of UPGR Impacts**
Critical Question:	What is the road map to answer the question?	How much average hourly MW could Western contract annually, given the variation in historical sales/purchase patterns over low, medium and high hydro generation years?	» Of this number, how much could tribal wind energy replace: • How much tribal wind energy is available? What sites would be available at the time of this study? • What is the maximum installed capacity of wind plants in terms of the effects in Western Balancing Area operations? • How much other wind is in Western's Balancing Area? • What sample tribal wind energy projects could be used to run a tribal wind scenario?	» If injecting this scenario on the existing transmission system, are there any transmission constraints that would prohibit Western from purchasing this wind energy? If so, how much would it cost to upgrade the transmission system to allow purchase?	» What are the economic impacts of this tribal wind energy scenario compared to a base case scenario for varying hydro generation conditions?

Work Element 2 – Analysis of Historical Western Purchase Requirements

Legislation Objective – Section 2606 (b) (1) The study shall review historical and projected requirements for, patterns of availability and use of, and reasons for historical patterns concerning the availability of firming power.

Western's gross power purchase requirement or excess (surplus) generation is the net of available hydro generation as compared to actual load obligation. There are several factors that impact Western's need to purchase power. Unlike most systems, Western's UGPR load pattern is fairly stable and predictable due to marketing plan characteristics. Energy generated from the hydro plants, however, shows wide variation due to availability of fuel (water) in the system. This variation is most significantly driven by the amount of water available in reservoirs for a given year—high reservoir levels allow high hydro generation, low reservoir levels limit hydro generation. Although capacity of the units does not change significantly with varying water levels, the amount of time the units can run at high outputs is determined by reservoir levels and targeted releases set by the Corps.

Typically, reservoir levels are influenced by annual runoff. Annual Missouri River Operating objectives (river traffic, environmental, flood control, etc) impose constraints as outlined in the Master Manual (http://www.nwd-mr.usace.army.mil/rcc/reports/mmanual/MasterManual.pdf). The AOPs provide yearly projections for the available energy from hydro generation (http://www.nwd-mr.usace.army.mil/rcc/aop.html). Unpredictable variability to these projections also occurs during the year. A relevant example is the reduced generation experienced through much of June and July 2008 as a result of significant flooding downstream of the upper Missouri River basin. The Corps estimates that actual generation during June and July (605,000 MWh) was about half of what was forecast on May 1, 2008 (1,233,000 MWh). Thus, approximately 600,000 MWh were not generated during this period to reduce the impacts of that flood event. (This energy shortfall had to be supplemented by market purchases.) Lack of river traffic and nesting Least Terns and Piping Plovers also played a role in this reduction once the major flooding event had passed in mid-July. Constraints on generation due to water availability and excess can be forecast in annual reports, but other factors can create unexpected variations in these forecasts.

When purchases are required, Western must purchase power on the open market at rates typically higher than Western's established composite hydro rate. If Western can acquire energy at below-market rates to supplement hydro generation resources, while not increasing costs associated with marketing excess, this would help Western meet its contractual power commitments at lower costs to its ratepayers.

The objective of this historical analysis is to estimate potential new wind energy resource capacity Western could consider adding to its hydro-generation based on historical purchase patterns. Discussion of costs and issues specific to integrating wind as this additional energy resource will be handled in subsequent Work Element summaries.

Data Gathering

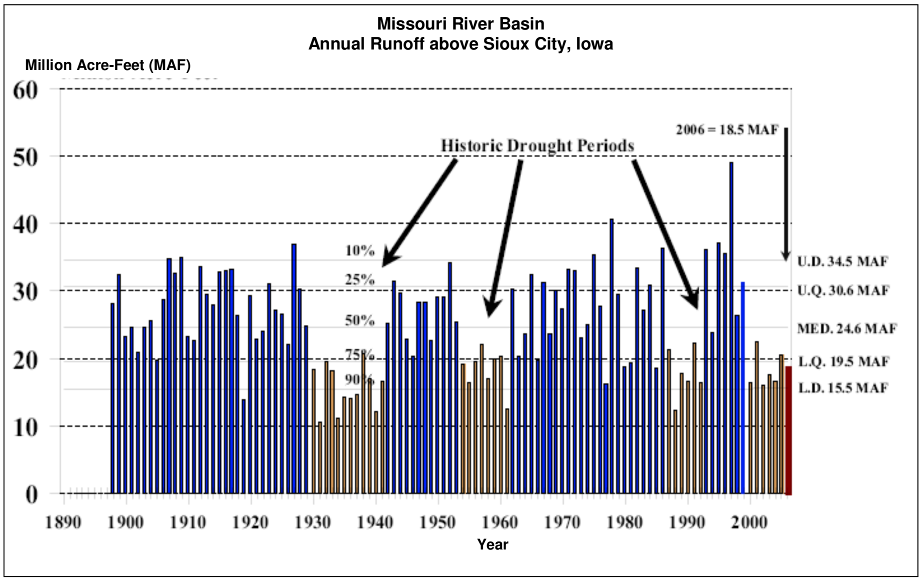
A minimum and maximum potential for energy that could be used to replace existing purchases was developed from Western's historical generation and load data. Minimum potential should be characterized in a high generation year when very few purchases are required; maximum purchase potential occurs in a low generation year. This gross capacity range was then further refined to identify a sample tribal wind scenario. Considerations, such as wind penetration levels (Work Element 2) and transmission constraints (Work Element 4), were used to refine the gross capacity range.

Western provided data that describes actual historical requirements and costs for Western's energy obligations not covered with available hydro generation. Since available fuel (water) for hydro-generation (and not load variability) is the significant factor impacting Western's purchases, three years were selected to represent high, medium, and low hydro generation production levels—1997, 2000, and 2005, respectively. Data provided by Western included allocation summary of firm electric and firm peaking service to Western's customers using seasonal contract rate of delivery (CROD). Other information included operational contracts as appropriate, and average hourly data for P-SMBP—ED from the Data Historian, including load and generation by plant for 1997, 2000, and 2005. This historical data formed the basis for a multi-year operational model that reflects Western's historical operations for low, medium, and high hydro generation years.

Initially, data requests were limited to years after 1999, since data prior to 1999 was not comprehensively available from Western's Data Historian. The years 2000 and 2005 were selected to represent high and low hydro generation years, respectively. Within the post-1999 timeframe, these two years recorded maximum and minimum hydro generation. However, upon comparison with Western's 40-year history, the 2000 generation production was closer to the historical median than the historical high generation year. After discussions with the Project Team, it was decided that 1997 would be used for the high hydro generation year, even if comprehensive data was not available. Upon receipt of the data set, it was determined that missing data from the 1997 generation and load totals was less than 2 percent of the total load and generation. Hourly estimates, scaled from the other two data sets, were used to complete the data set.

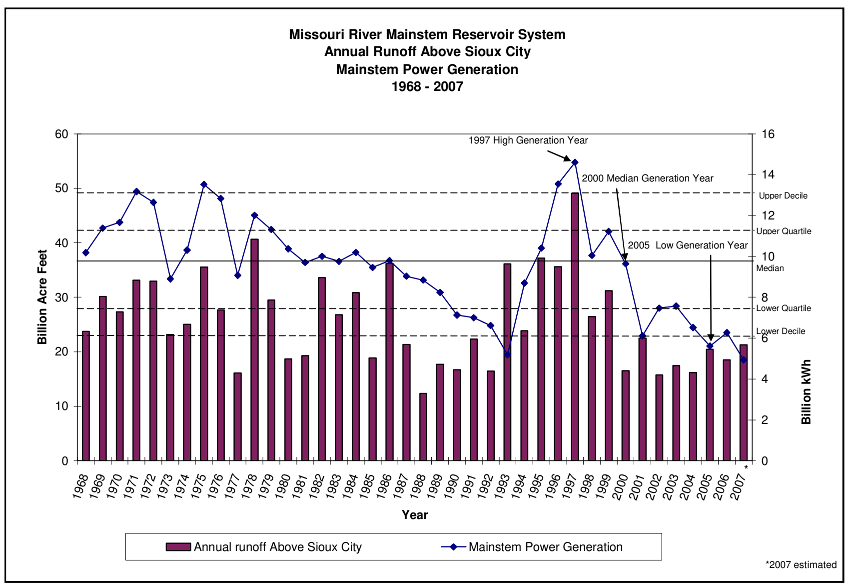
Western Historical Data

Total hydro-generation capacity allocated for the UGPR was determined during the early years after the System first filled. Since that time, the System has experienced both periods of drought and high water runoff. As of 2007, the Missouri River Mainstem, which is the portion of the river basin associated with the P-SMBP-ED, was in its eighth year of drought. The result is a reduction of hydro-power generation that caused purchase power expense to increase and revenue from non-firm energy sales to decrease. This variation in water level is the primary factor that determines hydro power generation on Western's system. Figure 2-1 shows the Missouri Mainstem Runoff above Sioux City, Iowa, including historic drought periods. Figure 2-2 shows the Missouri River Mainstem Runoff at Sioux City, Iowa, with Mainstem Power Generation overlaid to compare water runoff with hydro generation. Note that P-SMBP-ED also markets power from Reclamation's Canyon Ferry and one-half of the Yellowtail dams. It is not shown in Figures 2-1 and 2-2, but it is included in the analysis.



Missouri River Basin: Annual Runoff above Sioux City, Iowa, 1900-Present (Corps of Engineers)

Figure 2-1



Missouri River Basin: Annual Runoff above Sioux City, Iowa, & Mainstem Power Generation, 1968-2007 (Corps of Engineers)

Figure 2-2

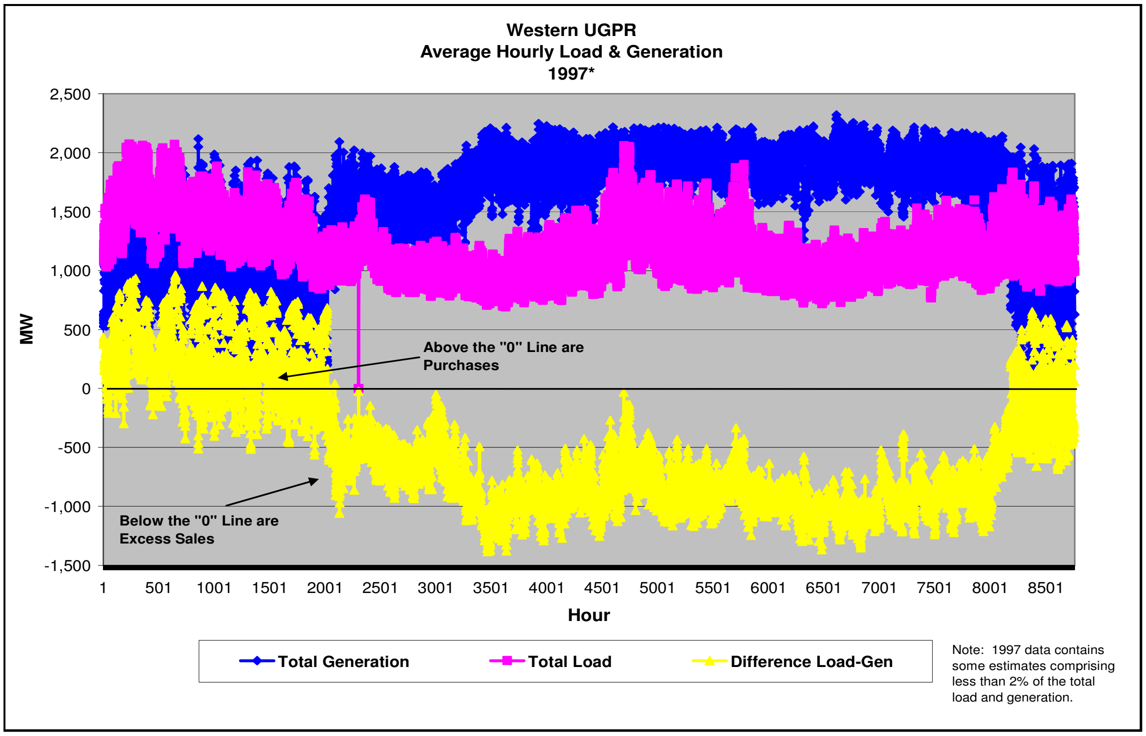
As documented in Figure 2-2, although the annual runoff and power generation do not always align, system storage and refilling requirements can create either a high water runoff year that is also a low generation year (i.e., 1993) or a low water runoff year that is a high generation year (i.e., 1998). Even though there are some deviations, generally periods of drought produce low hydro-generation and high water runoff years yield high generation. During periods of drought, or more specifically, years of low hydro generation, Western must purchase more power on the open market at rates much higher than Western's established composite firm power rate. In a low generation year, Western has purchased as much as 40 percent of its energy obligation. Even during high generation years, Western purchases about 5 percent of its energy obligation due to periodic hourly shortages.

Years selected to represent hydro generation scenarios were 1997 for the high generation year, 2000 for the base (or average) generation year, and 2005 for the low generation year. As seen in Figure 2-2, 1997 hydro-generation, at 15.27 billion kWh, was the maximum hydro generation documented over the System's 40-year history, and at the top of the upper decile of 13.2 billion kWh and upper quartile of 11.3 billion kWh. Hydro-generation produced in the year 2000, at 10.21 billion kWh, is very close to the system median of 9.8 billion kWh. The lowest hydro-generation years could be 1993 at 5.5 billion kWh or 2005 at 5.6 billion kWh. Data from 2005 was used due to historian data difficulties pre-1999. This is below the lower decile of 6.1 billion kWh and lower quartile of 7.5 billion kWh. [Since the analysis was in process late in 2007, 2007 data represented in Figures 2-1 and 2-2 is projected for the year. Corps's data was used to determine hydro generation scenarios; Western's historical data used in the marketing simulations includes both Corps generation data, and Reclamation data for slightly higher annual averages.]

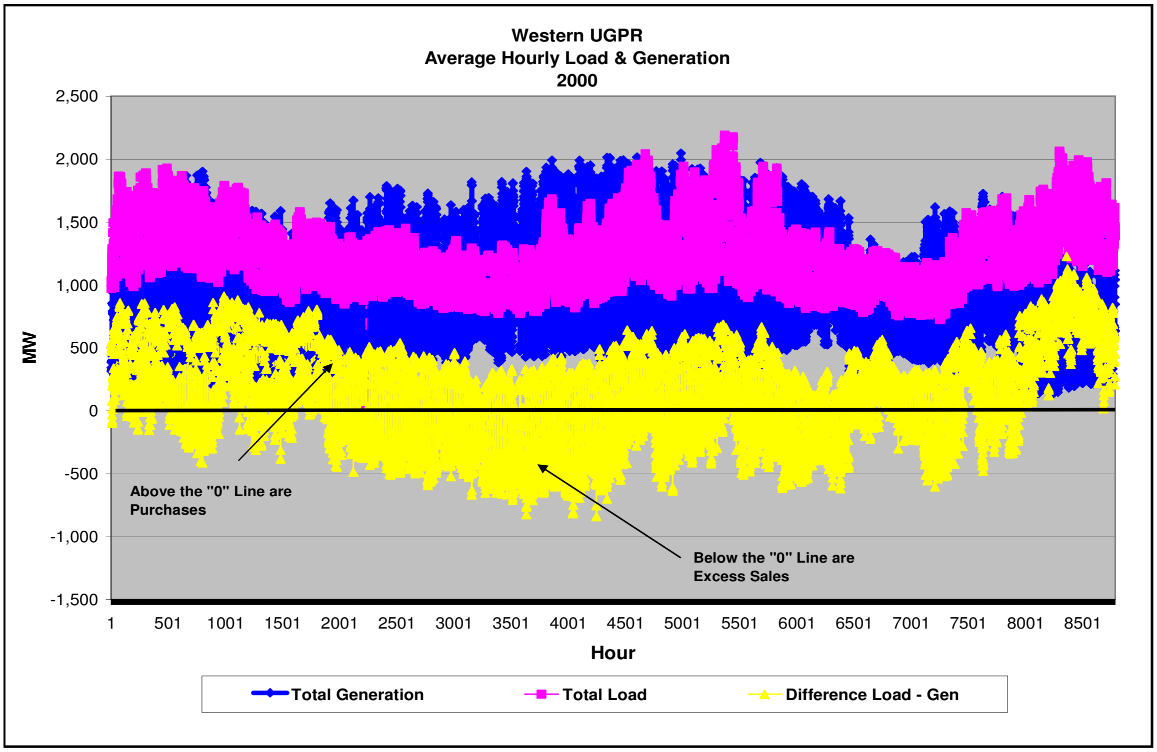
Western Purchases

The amount of energy Western has to purchase or sell in the market significantly impacts cost to Western's customers. Figures 2-3 through 2-5 overlay hourly generation with hourly loads for the three hydro generation scenarios, and show the difference between load and generation (if positive this difference represents purchases required to meet CROD allocations; if negative this number represents excess generation or surplus sales). As expected, 1997, the high generation year, shows substantial excess generation (most of the difference between load and generation are negative)—there are some purchases required during winter months (positive difference between load and generation), but excess generation is available for sale during most of the year. The base year, 2000, shows a more moderate pattern with some purchases and sales throughout the year (the difference between load and generation fluctuate between positive and negative). For 2005, the low generation year, purchases far exceed sales (most of the difference between load and generation are positive).

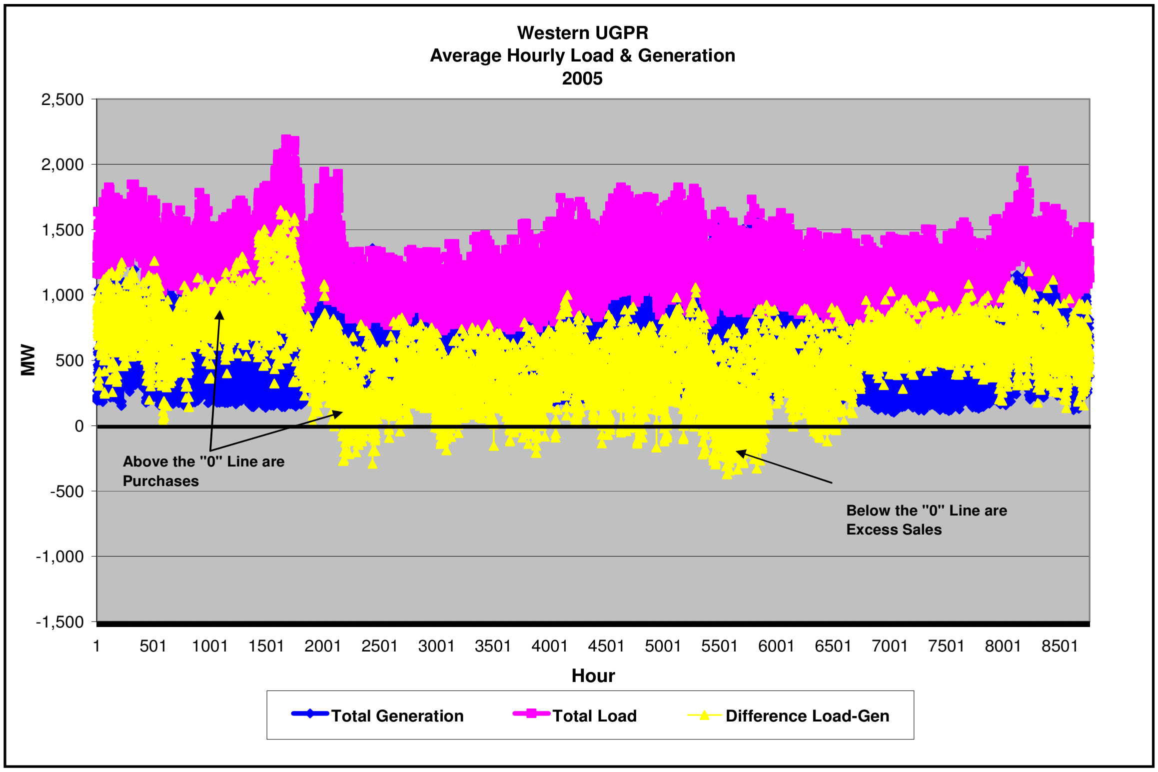
HIGH HYDRO Hourly Load, Generation, & Purchases, 1997
Figure 2-3



BASE HYDRO Hourly Load, Generation, & Purchases, 2000
Figure 2-4



LOW HYDRO Hourly Load, Generation, & Purchases, 2005
Figure 2-5

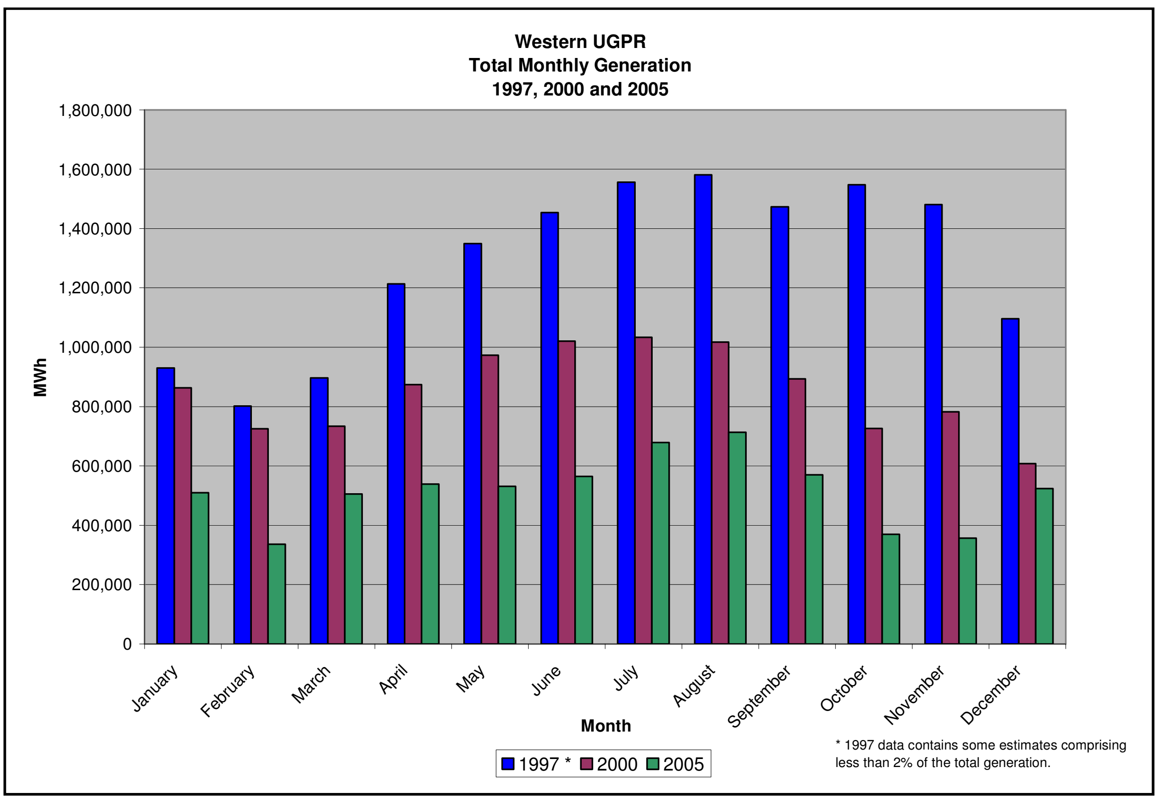


Seasonal/On and Off Peak Variation

Although the amount of water in the System is the primary factor determining costs to Western's customers, seasonal variation also influences purchase/sale balance. As illustrated in the previous figures (2-3 through 2-5), there are more sales during the summer than the winter (negative difference between load and generation). Even in the low hydro year, there are some summer sales. Conversely, in the high generation year, some purchases occur during winter (positive difference between load and generation).

Generation

The seasonal variation identified in Figures 2-3 through 2-5 is further understood by reviewing Figure 2-6. Hydro generation has a definite seasonal pattern. Weather (e.g., icing in winter) and regulation objectives outlined in the Master Manual (e.g., Navigation) influence seasonal hydro generation pattern. Figure 2-6 illustrates monthly energy generation for each of the three years analyzed. This graph shows that the seasonal pattern for hydro generation is consistent across the three hydro generation scenarios, with peak energy generation in summer months and lower levels of generation during winter months for all three years. Here, quantity of generation production is representative for each of the scenarios, but the seasonal pattern is also evident for all three scenarios.

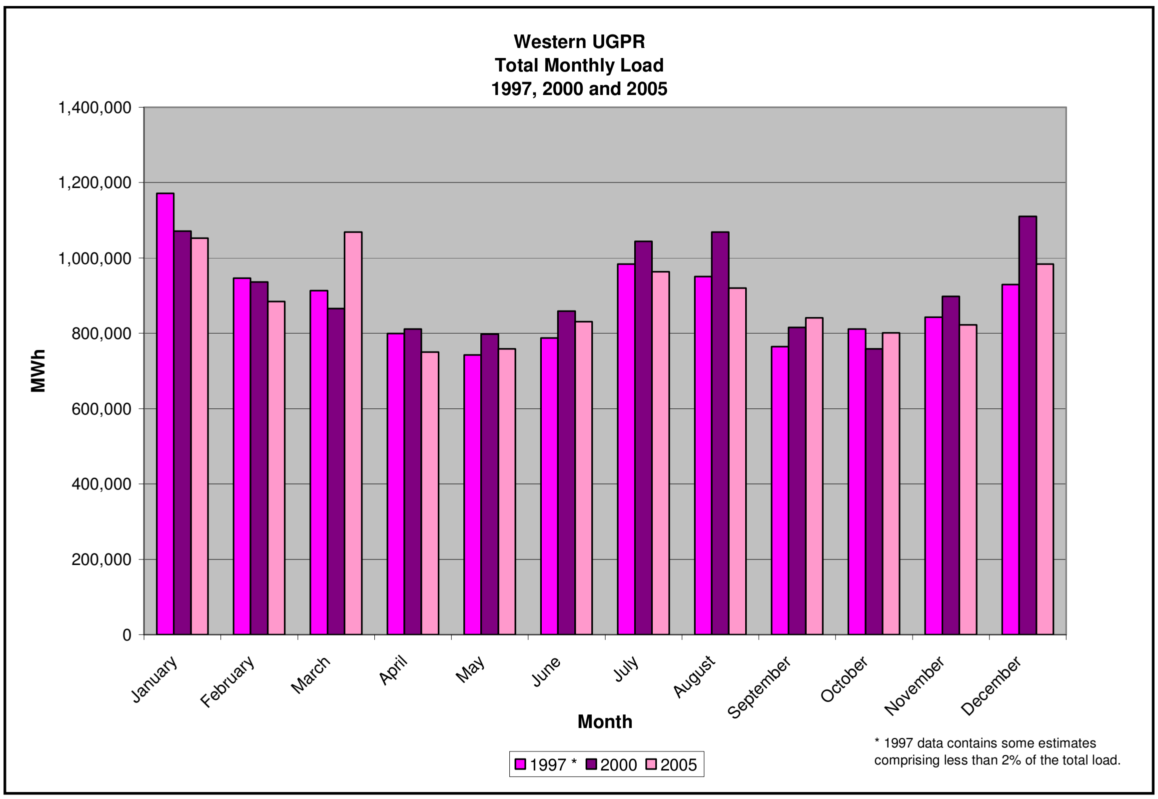


Total Monthly Generation: 1997, 2000, & 2005
Figure 2-6

Load

A similar graph of total monthly load energy requirements is shown in Figure 2-7. Note that seasonal variation is less pronounced, with peaks in both winter and summer. This pattern is consistent with traditional winter peaking nature of the Western UGPR load energy requirements that has recently begun to show some summer peaking characteristics. This graph also demonstrates a small variation of load energy requirements between varying hydro generation years. The graph does not show a bias for any of the hydro scenarios; maximums and minimums vary between years.

This load pattern is predictable, given the UGPR Marketing Plan CROD allocation used to determine Western's UGPR load. Therefore, Western's load patterns do not show the same variation that other system's load patterns show. A slight increase occurs during the heat of peak summer months (July and August) and the cold temperature experienced during winter months (December and January). CROD maximum capacity allocation for summer (post 2005) load is 2,077,617 kW and for winter is 1,987,440 kW. These customer allocations are not expected to change over the next several years. Hence, load pattern for energy delivered throughout the year can be reasonably represented by any of the three years analyzed.



Total Monthly Load Energy Requirements: 1997, 2000, & 2005
Figure 2-7

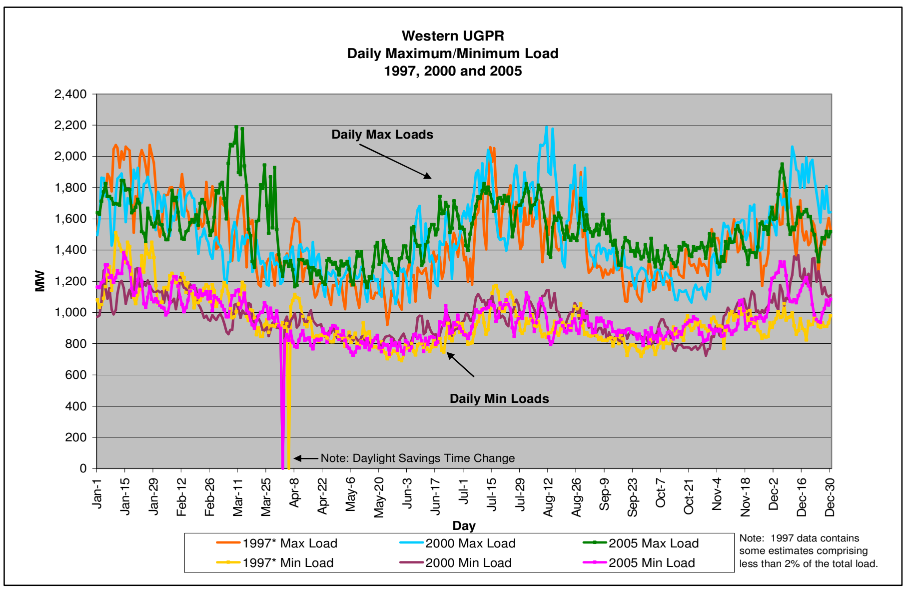
As seen in Table 2-3, total load energy requirements for each of the three years varies less than 4 percent, but does not track with water/generation level.

Table 2-3 Total Load For Each Year

	Total Load (Annual billion kWh)
1997 High Generation Year	10.64
2000 Average Generation Year	11.03
2005 Low Generation Year	10.68

Low variation in load energy requirements is also evident in Figure 2-8 where daily minimum and maximum MW demanded for loads for each year show very similar patterns with no bias due to hydro scenario. Although load patterns typically vary with weather, the load pattern for Western UGPR is relatively constant since Western's customers' allocations are determined by the UGPR Marketing Plan. In addition, 74 percent of UGPR's customers have chosen to receive fixed monthly power and energy deliveries from Western which further increases predictability.

Given the consistent nature of Western's load pattern and high variation in hydro-generation, the primary driver for Western purchases will be differences in hydro generation, not load pattern.



Daily Maximum and Minimum Load: 1997, 2000, and 2005
Figure 2-8

On/Off Peak Variations

Figures 2-9 through 2-20 depict one-week samples of hourly generation plus or minus purchases, or excess generation to total Western's load. The high hydro generation year (Figures 2-9 through 2-12) show primarily excess generation or sales throughout the year, with the exception of a few weeks in winter. The low generation year (Figure 2-17 through 2-20) exhibits purchases throughout the year except for a few on-peak hours during the summer. These figures reinforce seasonal patterns already identified—

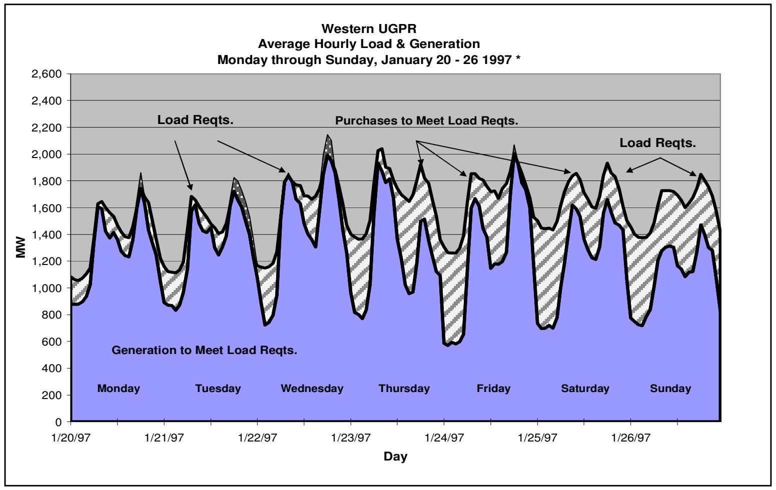
purchases occur during winter months even during a high generation year (1997), while a small amount of sales occur during on-peak summer hours even in a low generation year (2005).

In the base hydro year (2000 shown in Figures 2-13 through 2-16), the pattern of purchases and sales tends to be determined by on-peak or off-peak hours. Excess generation is available during on-peak hours, while purchases occur primarily during off-peak for both summer and winter. This pattern reflects hourly dispatch decisions made by Western's operations to purchase energy during low-cost, off-peak hours (minimize costs), and sell excess (surplus) generation during higher priced on-peak hours (maximize sales revenue), while maintaining the daily requirements set forth through Corps's Standing Orders and Master Manual constraints. This generation schedule allows Western to take advantage of off-peak returns during winter and maximize sales revenue in summer.

These weekly snapshots help to illustrate the different purchase patterns for the three hydro scenarios and can be used to visually estimate hourly average MW to offset purchases. In a high hydro year, all additional generation will be sold except for a few months during winter. In a low hydro year, 200 – 400 MW could be purchased almost every hour except during some on-peak periods during summer. In a base hydro year, off-peak purchases up to 800 MW occur throughout the year except during summer, when very little purchase occurs. Hence, when estimating a minimum and maximum potential for tribal wind energy that could be used to replace existing purchases, seasonal variation and on/off peak hours will be significant factors.

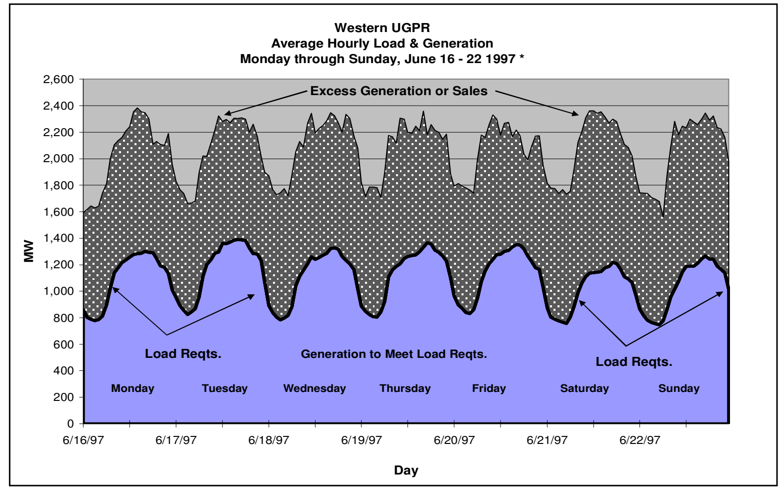
HIGH HYDRO SCENARIO

Winter

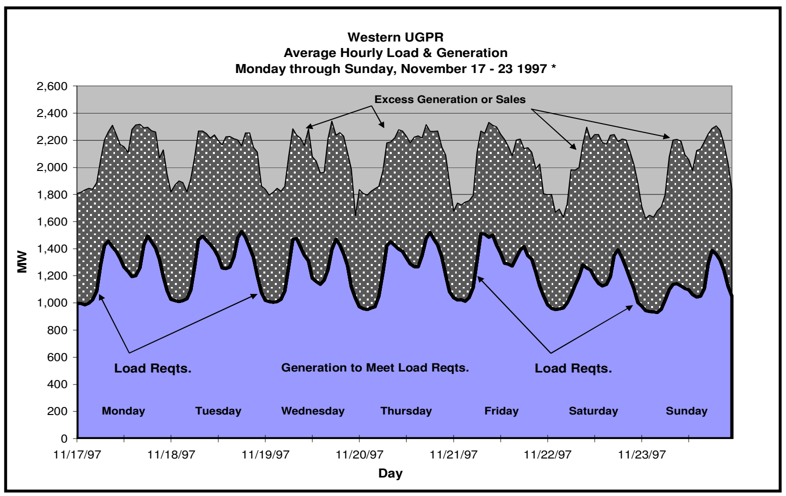


Hourly Load & Generation, January 20-26, 1997
Figure 2-9

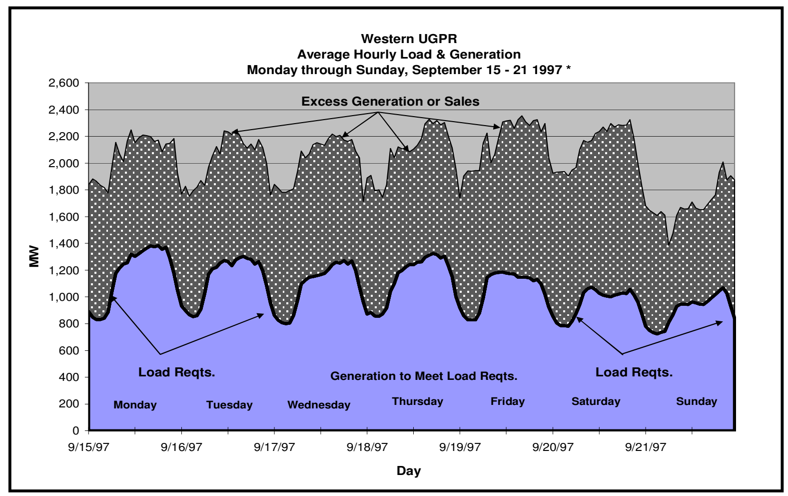
Summer



Hourly Load & Generation, June 16-22. 1997
Figure 2-10



Hourly Load & Generation, November 17-23, 1997
Figure 2-11



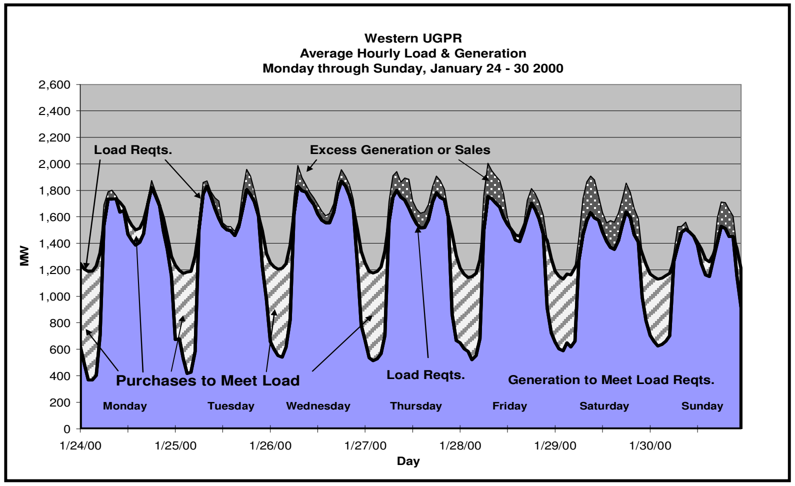
Hourly Load & Generation, September 15-21, 1997
Figure 2-12

Generation for Load | Purchases for Load | Excess Gen or Sales

Note: 1997 data contains some estimates comprising less than 2% of the total load and generation.

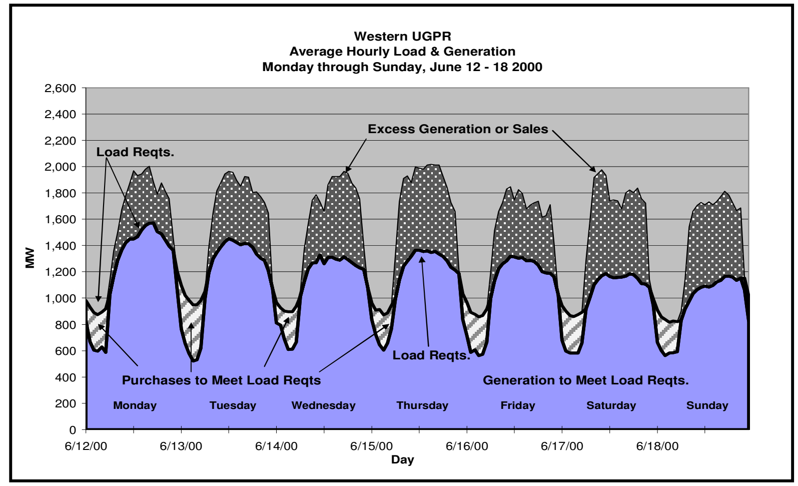
BASE HYDRO SCENARIO

Winter

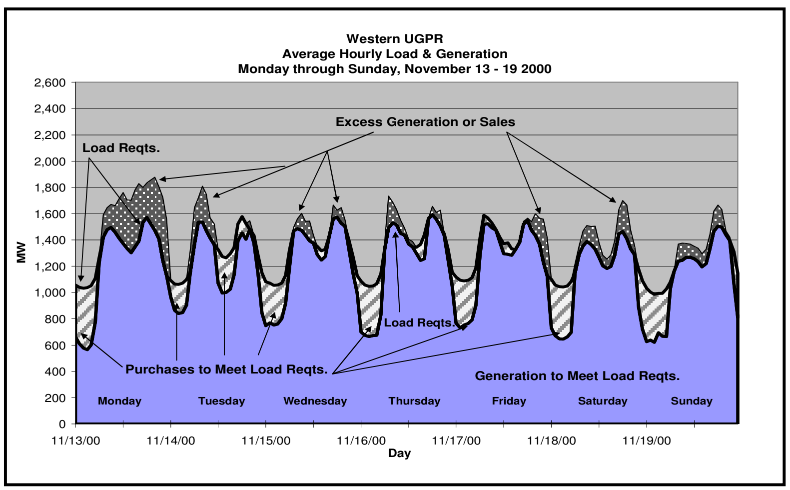


Hourly Load & Generation, January 24-30, 2000
Figure 2-13

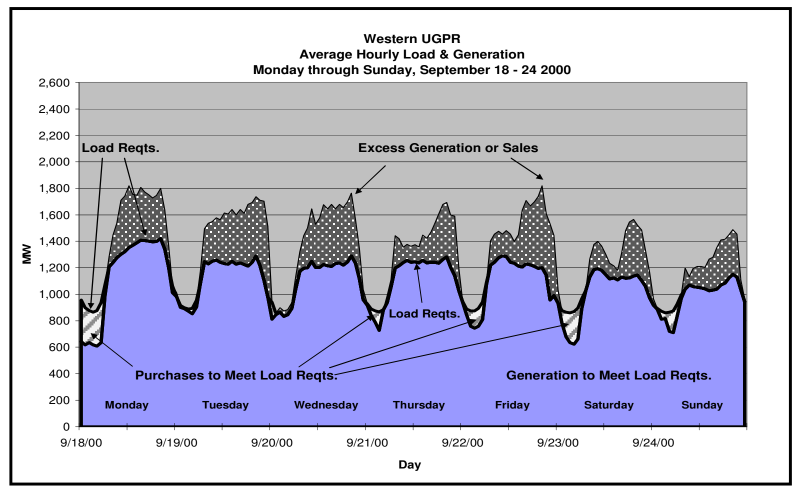
Summer



Hourly Load & Generation, June 12-18, 2000
Figure 2-14



Hourly Load & Generation, November 13-19, 2000
Figure 2-15

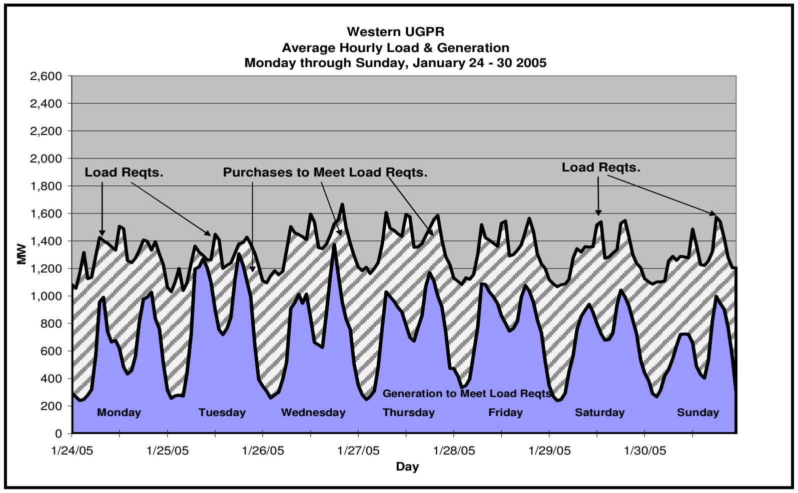


Hourly Load & Generation, September 18-24, 2000
Figure 2-16

Generation for Load | Purchases for Load | Excess Gen or Sales

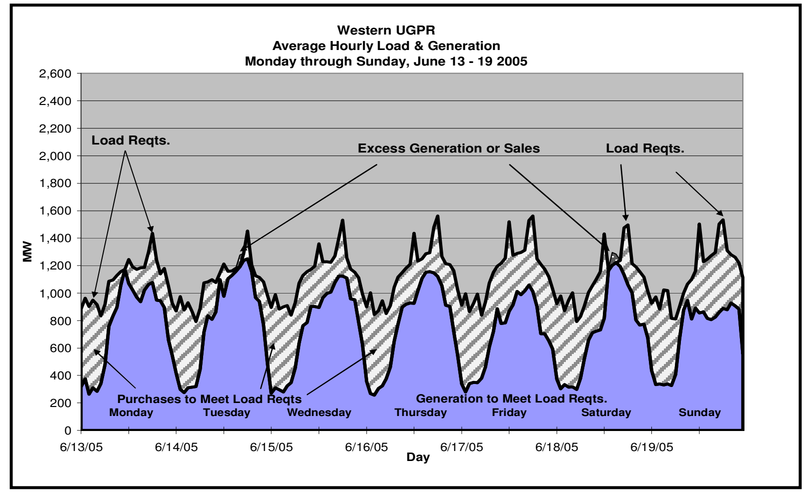
LOW HYDRO SCENARIO

Winter

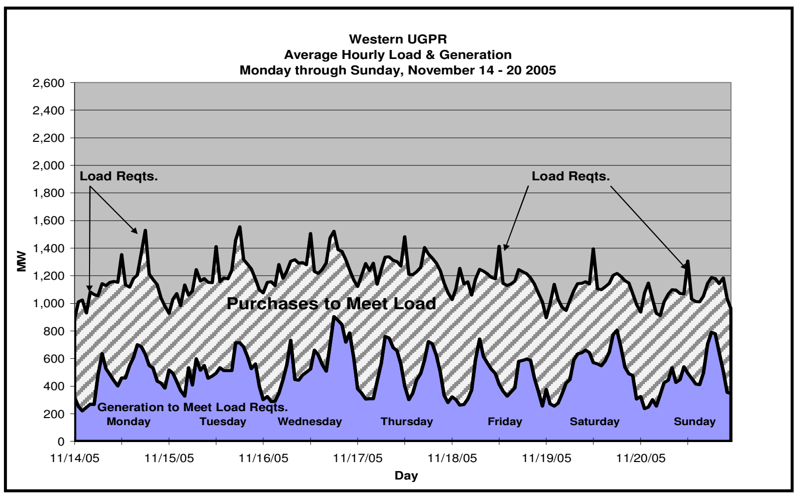


Hourly Load & Generation, January 24-30, 2005
Figure 2-17

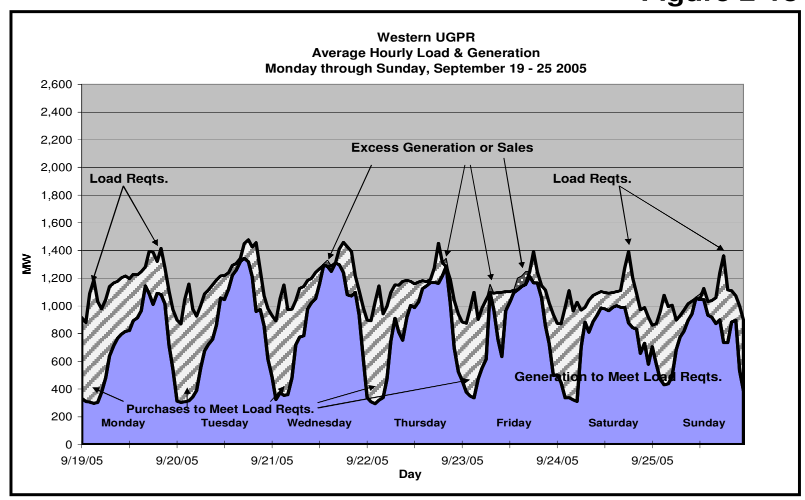
Summer



Hourly Load & Generation, June 13-19, 2005
Figure 2-18



Hourly Load & Generation, November 14-20, 2005
Figure 2-19



Hourly Load & Generation, September 19-25, 2005
Figure 2-20

Generation for Load | Purchases for Load | Excess Gen or Sales

Minimum and Maximum Potential for Capacity to Replace Western Purchases

As seen in Figures 2-9 through 2-20, purchases of 0 MW to 800 MW occur over the three hydro scenarios analyzed. The wide variation between years makes it difficult to identify a reasonable range for purchases that cover all three scenarios. Table 2-4 shows the annual three-year composite average of hourly MW purchases/sales, as well as On-Peak and Off-Peak averages. As discussed in the previous section, a composite average can not represent seasonal and on/off-peak influences that strongly impact purchase pattern. As shown in Table 2-4, the composite average of 20 MW is deceptive since the summer three-year average hourly MW is actually 192 MW of excess (surplus), while the winter three-year average hourly MW purchased is 236 MW. These numbers do not help to identify a meaningful range for substituting tribal energy for Western purchases.

Similarly, in Table 2-5, extreme years do not provide a meaningful bandwidth. The high generation year (1997) shows all on and off peak, summer and winter hourly averages as excess (surplus) sales, while the low generation year (2005) shows all on- and off-peak, summer and winter hourly averages as purchases. It has already been shown that some purchases occur during high generation years (in winter, see Figure 2-9) and some sales occur during a low generation year (on-peak summer, see Figure 2-20).

The base generation year (2000) shows both purchases and sales with similar hourly patterns to the two extreme hydro generation years—on-peak excess generation/sales in the summer (see Figures 2-14 and 2-16) with an average in Table 2-5 of 224 MW for the base hydro year and off-peak purchases in winter (see Figures 2-13 and 2-15) with an average in Table 2-5 of 444 MW for the base hydro year. Although the patterns are similar, the quantity is substantially different. When the base year averages 224 MW sales on-peak summer, the high hydro year shows an average of 862 MW sales on peak summer. Although the low hydro year shows 299 MW of purchases for this category, it is the lowest average purchase recorded for the four categories. When the base year averages 444 MW purchases off-peak winter, the low hydro year shows an average of 705 MW off-peak winter. The high hydro year shows an average of 47 MW of sales for this category, but again, it is the lowest average sale of the four categories for the year. Given the representative patterns in the base year, it provides the most logical representation for identifying a range or bandwidth that Western could consider to balance its variable hydro-generation. As the median scenario, it also represents 19 of the last 40 years (see Figure 2-2).

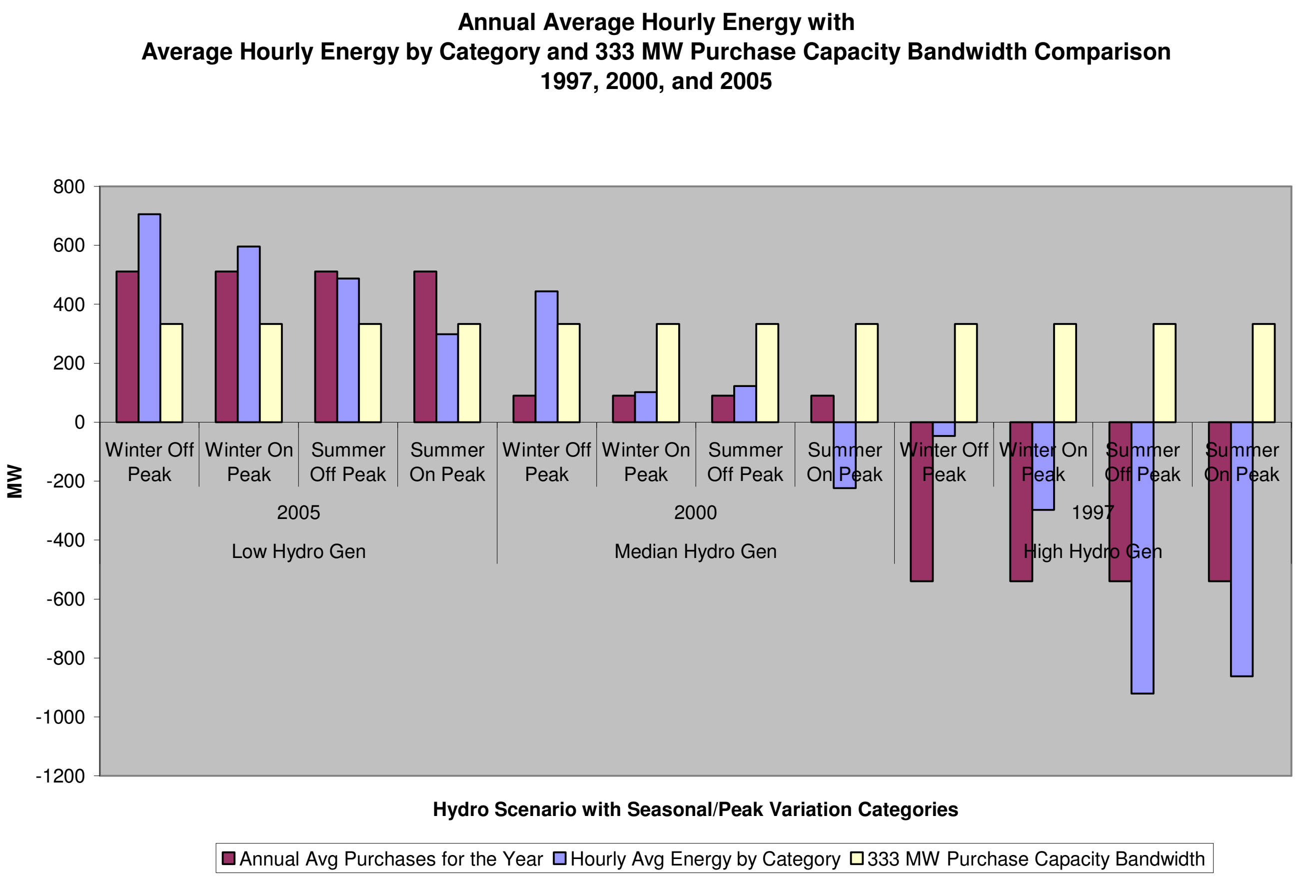
Table 2-4 Average Three Year Hourly MW Purchases/Sales
(Positive = Purchases; Negative = Sales)

	Composite On/Off	On-Peak	Off-Peak
Annual 3 Year Hourly Average (MW)	20	-66	130
Summer 3 Year Hourly Average (MW)	-192	-264	-102
Winter 3 Year Hourly Average (MW)	236	135	366

Table 2-5 Average Hourly MW Purchases/Sales (Positive = Purchases; Negative = Sales)

	1997		2000		2005	
Annual Hourly (MW)	-540		90		511	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Annual Hourly (MW)	-583	-486	-63	283	447	594
Summer Hourly (MW)	-862	-920	-224	122	299	488
Winter Hourly (MW)	-298	-47	102	444	595	705

Since on-peak generation results in excess (surplus) in summer, the minimum of the range would be zero. Establishing the maximum of the range would suggest 444 MW (winter hourly average for off-peak in 2000). However, off-peak short falls are offset by peaking return contracts with Western's customers supplying thermal generation. There are three peaking contracts currently in place with Western customers. These contracts account for approximately 111 MW of winter off-peak purchases. Hence, a range or bandwidth for the capacity that could be used to offset historical energy purchases, or a Purchase Capacity Bandwidth, is 0 to 333 MW. (Note: This does not represent wind nameplate capacity.) Figure 2-21 compares the average hourly MW for the year with the average hourly MW by category and proposed Purchase Capacity Bandwidth of 333 MW.



Annual Average Hourly MW with Average Hourly MW by Category and 333 MW Purchase Capacity Bandwidth Comparison Figure 2-21

Purchase Capacity Bandwidth represents the capacity that could be used for tribal wind energy, given energy purchases that Western has made historically. The focus when determining this bandwidth is based on balancing purchases/sales required during high, medium, and low hydro generation years. The range is moderated on the high side by potential impacts of having excess generation due to adding tribal wind to Western's resource—the risk of having to sell any excess tribal wind energy at a price that is less than the cost of that energy. If there are a high number of years that provide high hydro generation over a projected time period, and the market for that excess tribal wind generation is not sufficient to cover its cost (e.g., off - peak), the energy surplus will likely result in a cost to Western's firm power customers.

This historical analysis simply looks at the quantity of energy from historical purchase data, in grossly averaged form. Purchase Capacity Bandwidth provides starting boundaries in development of the tribal wind scenario for the production costing model to be performed in Work Element 5. This historical analysis of purchases and sales has to be further refined by current operational and business forces that shape the feasibility of integrating tribal wind onto Western's system.

Refining Purchase Capacity Bandwidth for a Tribal Demonstration Project

Purchase Capacity Bandwidth for tribal wind to offset historical energy purchases has been identified at 0 – 333 MW. Further refinement of this range is needed, due to issues relevant to adding any new generation to Western's UGPR system. Transmission congestion resulting from new generation injections may limit the amount of energy that can be added to the transmission system. As additional generation is placed on the system, upgrades necessary to address power flows may be necessary before generation can be added. Any transmission constraints identified as a result of adding tribal wind would either limit the amount of tribal wind that could be added to the system, or increase cost of adding tribal wind to the system by the costs associated with required upgrades. The power flow analysis is discussed in Work Element 4. Nodal market simulations were completed to identify potential transmission bottlenecks for tribal wind energy delivery, and to measure if there are likely curtailment hours when tribal wind energy might not be deliverable due to transmission constraints. Results of the nodal analysis are discussed in Work Element 5.

Issues specific to using wind as the energy source are also important to consider when refining Purchase Capacity Bandwidth. Using tribal wind to supplement purchases requires examination of operational considerations unique to wind as an intermittent energy source, as well as specific tribal wind energy resources available. Since wind is not a capacity resource or dispatchable, operational considerations unique to wind include increase in operating reserve requirements necessary to maintain power system reliability and security. Given variability in wind generation, system operators must ensure that enough generation capacity is operating on the grid at all times, even when wind generation is low. Operators deal with load variability in systems without wind. Adding wind generation to a system may require operators to carry additional operating reserves to accommodate added variation of the wind generation. It is the load net wind generation variability that operators must manage. Regulation and load-following reserves may need to be added to maintain system balance and security.

At small penetration levels (less than 15 percent) studies indicate that this regulation and load following reserve requirement may not be a significant factor. However, at wind penetrations in the 20 percent range, this reserve requirement may become a more important consideration. Hence, using wind as the energy resource to replace Western's purchases requires a full accounting for all wind expected to be in Western's Balancing Area during the study time frame. Tribal wind resources are evaluated in terms of providing this energy to Western. Work Element 3 discusses this assessment.

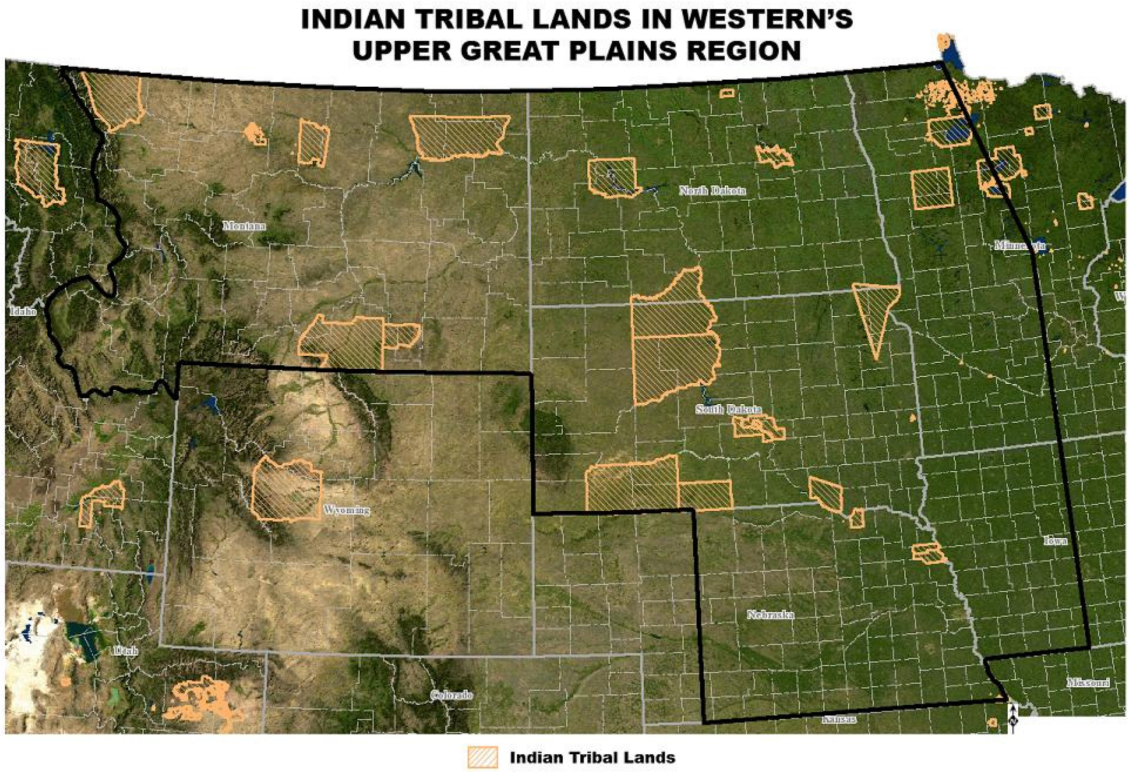
Work Element 3 – Wind Project Identification

Legislation Objective - Section 2606 (b)(3) assess the wind energy resource potential on tribal land.

The UGPR sells power in Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota. Within this region, Western has 25 Native American Tribal customers (see Figure 2-22):

- Blackfeet Nation
- Cheyenne River Sioux
- Chippewa Cree-Rocky Boy
- Crow Creek
- Crow
- Flandreau Santee Sioux
- Fort Belknap Indian Community
- Fort Peck Indian Tribes
- Lower Brule Sioux
- Lower Sioux
- Northern Cheyenne
- Oglala Sioux-Pine Ridge
- Omaha Tribe of Nebraska
- Ponca Tribe of Nebraska
- Rosebud Sioux
- Santee Sioux Tribe of Nebraska
- Sisseton-Wahpeton Sioux
- Spirit Lake Sioux
- Standing Rock Sioux
- Three Affiliated Tribes
- Turtle Mountain Chippewa
- Upper Sioux
- White Earth Indian Reservation
- Winnebago Tribe of Nebraska
- Yankton Sioux

The tribal lands are geographically dispersed throughout the region. This region is recognized as having one of the most promising wind resource potentials in the United States (US DOE, 2008). Several wind integration studies have been conducted to begin the process of harnessing this wind into energy exported to the grid. Some of the tribes within the UGPR have already begun wind production on their lands.



Indian Tribal Lands in Western's UGPR
Figure 2-22

Since one of the WHFS objectives is to determine feasibility of integrating tribal wind onto Western's system, this work element analyzed how much of the Purchase Capacity Bandwidth identified in Work Element 2 (0 - 333 MW) could be supplied by tribal wind energy. This Work Element also established initial parameters for identifying a demonstration project size. To make this determination, several steps were necessary: 1) Identify tribal wind project development currently underway within the UGPR, and where and when that development is occurring; 2) Determine wind (intermittent) energy potential on Western's system from an operations standpoint; and 3) Evaluate existing and future non-tribal wind energy that is expected to be in Western's Balancing Area. Once these parameters were outlined, the final objective of this work element was to identify assumptions to be used in the Tribal Wind scenario for transmission analysis (Work Element 4), as well as production and operational modeling simulations in Work Element 5.

Questionnaire Development

To gauge potential and actual progress for Tribal wind project development in the region, a questionnaire was developed to collect information on proposed tribal wind. The draft questionnaire was reviewed by the Project Team, before being finalized. The Wind Demonstration Questionnaire was distributed to all 25 Native American Tribes in Western's UGPR. The questionnaire requested information from tribes interested in participating in a potential demonstration project as part of the EPA 2005, Section 2606 study. Six tribes responded, indicating plans for wind plant projects, and the ICOUP responded representing eight tribal projects. A total of 14 tribal questionnaires were received by the deadline. One tribe provided a response after the deadline. Informal discussions with some of the tribes that did not respond revealed concerns over the proprietary nature of their wind development plans, or the lack of formal plans as the rationale for not responding to the questionnaire.

In completing the questionnaire, tribes were asked to outline near-term plans for wind plants (through 2010), and plans for projects beyond 2010, to gauge a total long-term projection. Information regarding siting, turbine selection, and development details were also requested, but kept confidential when provided.

The questionnaire was designed to provide an assessment of wind plant development plans. This information was used to identify project assumptions (e.g., turbine model for power curve) necessary for other parts of the study. Siting information was also requested to assist in selecting points for wind data collection, to develop a typical interconnection design for cost estimates, and to compare pro forma costs to calculate a proposed cost of energy for tribal wind. The Wind Demonstration Questionnaire is provided in Appendix C.

For purposes of this study, the tribal wind assessment was limited to those tribes responding to the questionnaire, which signifies an interest in developing wind in the near future. Although tribes not responding still have the potential to develop wind, the likelihood of near-term development is unknown. Only tribal projects outlined in the questionnaire were used for the tribal wind energy assessment documented in this section.

Results from this questionnaire were not used to prioritize projects or qualify projects for selection as a demonstration project. Next steps for demonstration projects and suggested requirements for demonstration project(s) are outlined in Section 4.

Wind Project Review and Identification

The 14 tribal projects identified in the completed questionnaires indicated a total of 748 MW projected nameplate capacity through 2010, and more than twice that, 1,748 MW, for future build-out capacity. If wind potential for the tribes that did not meet the original deadline for completed questionnaires is included, assuming an average of 50 MW for those sites, total build-out tribal nameplate wind projection for the UGPR could exceed 2600 MW.

Projects represented in the 14 tribal responses were included in this assessment. Five tribes proposed multiple sites for a total of 22 tribal wind project sites. These sites were split into West, Omaha, and East regions. These sub-regions correspond to the physical configuration/ boundaries of the transmission system in the UGPR. West region consists of sites in Montana, including the Blackfeet Community Wind Project and the three sites in the Fort Peck Assiniboine & Sioux Tribes Wind Project. These sites would interconnect on the Western grid. Omaha region includes Four Winds and ICOUP Omaha; the Omaha region is not in the UGPR Balancing Area. East region includes the other 16 sites: ICOUP sites of Ft. Berthold, Spirit Lake, Lower Brule, Pine Ridge, Yankton, Flandreau (2 sites) and Rosebud, Rosebud Sioux Tribe-St. Francis sites (2 locations), Cheyenne Wind (3 locations), and Standing Rock Sioux (3 locations).

As part of the wind data requirement for sub-hourly analysis, 3TIER was retained by Stanley Consultants to provide wind energy profiles for wind injections planned within the UGPR Balancing Area for the period of the study. 3TIER provided data for tribal projects, based on locations indicated in the tribal questionnaire responses. Stanley Consultants provided location maps to the tribes for review prior to sending location information to 3TIER. No attempt was made to optimize (mirco-siting) site wind speed potential. It is assumed that the tribes will make this effort as part of their specific development efforts. The Inception Report completed by 3TIER is provided in Appendix D.

The 3TIER data consisted of hourly averaged wind speed and resulting wind energy production by site, based on nameplate projection for each site indicated in the questionnaire response, The GE 1.5 SLE power curve was used. Given the differences in maturity of various tribal wind projects, some tribal projects had not yet identified a preference in specific wind turbine manufacturers. Therefore, the GE 1.5 SLE wind turbine and power curve was used as typical in this work element as well as in remaining work elements. Use of this specific wind turbine is not an endorsement by Western, nor does it indicate Western's preference for a particular turbine.

Hourly average wind speed is determined from a numerical weather simulation at an 80-meter turbine height. This data was part of the overall data request for a wind integration study. Data was not collected to be used in a production or performance application. It provides general wind energy potential and profiles for this study. As indicated above, data is not presented to suggest maximum wind energy potential; it provides a representative profile for each tribal project site, but is not intended to establish a generic wind profile for the region. Energy totals listed in Table 2-6 provide only a general estimate for tribal wind energy development near term. As stated earlier, since some tribes did not respond to the Wind Demonstration Questionnaire, this energy estimate does not include all tribal wind energy potential in the UGPR.

Table 2-6 2010 Total Annual Wind Energy for all Tribes (Year 2000)

Region		East (MWh)	West (MWh)	Omaha (MWh)
East	Rosebud-St. Francis	110,062		
	ICOUP-Lower Brule	143,093		
	ICOUP-Ft. Berthold	153,442		
	ICOUP-Pine Ridge	156,297		
	ICOUP-Spirit Lake	160,153		
	ICOUP-Yankton	164,490		
	ICOUP-Flandreau	166,110		
	ICOUP-Rosebud	181,585		
	Cheyenne Wind	316,871		
	Standing Rock	381,392		
West	Ft. Peck		107,966	
	Blackfeet		117,942	
Omaha	Four Winds			34,200
	ICOUP-Omaha			170,060
Total		1,933,495	225,908	204,260

Wind Energy Potential in Western's Balancing Area

Wind energy is an intermittent resource requiring an increase in regulation and load following reserve requirements necessary to maintain power system reliability and security. Wind integration studies conducted in the United States have considered impacts that wind has on transmission systems, both in terms of congestion and costs of integration. The concept of wind penetration has become a central consideration when integrating wind onto a transmission system.

Capacity penetration, the ratio of the nameplate rating of wind plant capacity to peak load of the balancing area, has become a point of reference to help determine potential impact that wind energy might have on a system. As an example of this calculation, given the peak load for Western's Balancing Area was 3090 MW in 2008, a 15 percent capacity penetration on Western's Balancing Area would integrate **464 MW** nameplate of wind; a 25 percent capacity penetration would integrate **773 MW** nameplate of wind

Previous wind integration studies indicate that incremental reserve requirements increase with wind penetration level. Most studies suggest that penetrations above 20-25 percent require reserve requirements that become noticeable in the balancing area. A summary of wind integration studies conducted in the United States recently published by Utility Wind Integration Group provided this finding related to impact of wind capacity penetrations:

"On the cost side, at wind penetrations of up to 20% of system peak demand, system operating cost increases arising from wind variability and uncertainty amounted to about 10% or less of the wholesale value of the wind energy. These conclusions will need to be reexamined as results of higher-wind-penetration studies-in the range of 25%-30% of peak balancing-area load—become available. However, achieving such penetrations is likely to require one or two decades." (UWIG, 2006)

The Wind Integration Study conducted by EnerNex for Western in 2006 came to a similar conclusion for Western's Balancing Area, "…it can be concluded that wind has little impact on the various metrics at 100 MW or 200 MW penetration levels. At 500 MW, some of these impacts became noticeably larger in magnitude, and were further magnified at the 1,000 MW penetration level" (Zavadil, 2006). The range of regulation capacity required to compensate for additional fluctuations in the balancing area demand due to wind generation for this study ranged from 1.2 MW for 250 MW of wind generation to 15.9 MW for 1,000 MW of wind generation.

As wind penetration levels increase, reserve requirements also increase. Penetration levels above 25 percent have not been considered in depth in previous studies. Typically, costs associated with integrating wind results from these additional reserve requirements. Additionally, operational complexities to handle wind in a balancing area increase with higher levels of wind penetration. Considering the findings from previous wind integration studies, and that the goal of the WHFS is to look at economic feasibility of a Tribal Wind Demonstration Project, a maximum wind penetration of 25 percent for Western's Balancing Area was used for this study. This maximum penetration level was used to minimize costs in the economic analysis for additional wind in Western's Balancing Area. It was also considered a prudent maximum, given operational considerations near term. This maximum penetration was used for purposes of studying this Tribal Wind Demonstration Project only, and does not suggest a maximum penetration for Western's Balancing Area in the long run.

To compare this maximum penetration of 25 percent, or 773 MW of wind nameplate capacity on Western's Balancing Area, with the Purchase Capacity Bandwidth, a wind plant capacity factor must be assumed. A plant capacity factor measures actual energy production of a plant relative to its potential production at full utilization over a given time period (US DOE, 2008). The Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007, uses data provided from actual projects to provide statistics for wind projects in different areas of the country. This report documents average capacity factors for wind plants in the Heartland area (Midwest states) during 2006 at 40.8 percent (US DOE, 2008). Using this capacity factor to calculate wind nameplate capacity for maximum value (333 MW) of the Purchase Capacity Bandwidth, will yield 816 MW or a 26 percent capacity penetration. Since this is greater than a 25 percent capacity penetration, maximum wind in Western's Balancing Area considered for this study will be 773 MW nameplate capacity.

Assessment of Existing Wind in Western's Balancing Area

Existing and future wind projects expected in Western's Balancing Area near term had to be assessed to determine the amount of tribal wind to incorporate into production modeling scenarios. Currently, there are 158 MW of wind in Western's Balancing Area, with another 265 MW nameplate capacity planned for integration in the Balancing Area by 2011. Generation from Western hydro assets is already moderated in response to large-scale wind power in the balancing area. These existing and expected non-Western load serving wind projects within the balancing area are a key component of the operational impact analysis. They were a consideration in the total wind penetration analysis and ultimately will impact how much wind Western will allow in its balancing area.

Western is negotiating wind resources to supply a 5-year contract that would provide up to 600 MW nameplate capacity starting in 2011 and continuing through 2015. For purposes of this study, only 300 MW from the 5-year contract was assumed. The 158 MW existing and 265 MW projected wind, plus 300 MW from a 5-year contract equates to 723 MW of wind nameplate capacity in Western's Balancing Area through 2015, or 23 percent wind penetration. Concurrent to this study, other wind projects under development may not have been included since maturity of those projects was not clear. Further, these estimates do not consider wind generation facilities constructed within Western's service territory but are not serving Western load or non-Western load within Western's balancing area. Approximately 180 MW are electronically metered out of Western's balancing area thus this wind energy does not impact the operational considerations evaluated in this study.

Although tribal wind could potentially replace the 5-year contract wind in 2015, the 2606 legislation is looking to test feasibility of a Tribal Wind Demonstration Project in the near term, around 2011. To conduct the feasibility assessment, a 50 MW Tribal Wind Demonstration Project was used. This brings total nameplate capacity to 773 MW with a wind penetration up to 25 percent--the maximum identified above. For purposes of the 30-year market simulations, 300 MW of tribal wind profiles were used to replace the 5-year contract wind, post 2015.

The maximum generating capacity Western could utilize had to be estimated based on the difference between generating capacity already engaged through 2015 and its contracted level of load, which is approximately 2,000 MW. Western operates with a legal charter that obligates it only to provide power to its contracted load, and does not authorize it to amass additional generating capacity that would make it a net seller of electricity. Taking into account the wind and hydro assets already expected in the Balancing Area as well as the maximum amount of load to serve, the maximum capacity for a Tribal Wind Demonstration Project in the near term was judged to be 50 MW. The primary factors that constrained the maximum project size reflect legal considerations of Western related to its charter and pre-existing business commitments. The technical feasibility of integrating wind with hydro in the Western Balancing Area is demonstrably higher than 50 MW given the 723 MW of wind expected in the system between 2011-2015

As indicated earlier in results from the Western Wind Integration Study, impacts (incremental regulation and load following requirements) became noticeably larger in magnitude at 500 MW wind nameplate (or just over 15 percent penetration on Western's Balancing Area) (Zavadil, 2006). To assess these impacts, EnerNex conducted a sub-hourly analysis to determine how Western's operating reserve requirements would be affected by addition of wind penetration levels up to 25 percent to Western's Balancing Area. The sub-hourly analysis is discussed in more detail in Work Element 5.

Work Element 4 – Transmission System Evaluation

Legislation Objective - Section 2606 (b)(4) Determine seasonal capacity needs and associated transmission upgrades for integration of tribal wind generation and identify costs associated with these activities.

The above legislative objective is also addressed in Work Element 5 of the WHFS Work Plan. Work Element 5 describes the Operational Nodal Study and discusses potential seasonal constrained transmission capacity hours.

Work Element 4 discusses the transmission analysis for summer peak conditions. Details of this transmission study are included in Appendix F.

Introduction

The intent of the transmission analysis is to identify overall transmission system improvements required to support tribal wind development in Western's UGPR. Tribal energy projects identified in Work Element 3 were used to evaluate these potential transmission impacts. Regardless of the analysis outlined herein, tribal wind project(s) will likely be subject to the Western Open Access Transmission Tariff (OATT) process, and therefore, will likely require formal Feasibility, System Impact and Facility Studies be performed at a later date for actual Interconnection and Network Service, as with any other generation project.

Base transmission systems reflect transmission improvements in the grid as identified by Western for the study period.

Estimates of required sample wind project physical interconnection requirements will be determined, based on similar wind projects and transmission reliability standards.

Previous wind-transmission system network studies, specifically the Dakota Wind Transmission Study (DWTS) (ABB, 2005), provided significant background data in support of the analysis. The DWTS reviewed impacts of insertion of 500MW of wind turbines into the electric transmission grid at various locations throughout North and South Dakota. The studies provided a detailed analysis of transmission grid impacts including power flows, short circuit, and transient stability considerations. The report provides a significant data resource for quantifying transmission response to wind energy operations on the transmission grid.

Transmission Analysis Approach

Two PSS/E power flow computer models were developed; one for the Eastern Interconnection (East Grid) and one for the Western Interconnection (West Grid). Both models concentrated on the Western Balancing Area. As discussed in the WHFS Work Plan (see Work Element 1), the transmission analysis concentrates on load flow analysis.

Background

The Western transmission grid was designed to collect and transmit electrical energy from Reclamation and Corps hydroelectric dams in the Missouri River watershed to preference customers throughout the upper Midwest and West.

Western has the responsibility to meet capacity and energy requirements in contracted amounts in six (6) UGPR states - Montana, North Dakota, South Dakota, Nebraska, Iowa, and Minnesota. Western also provides reserve/regulation for its Balancing Area in specific contracted amounts. Operational dispatching functions are performed by Western's Watertown, SD, Operations Center.

Western's electric transmission facilities were analyzed to identify major issues associated with summer peak conditions for addition of tribal wind to the system. The ability of the Western Balancing Area to transmit the tribal wind energy to Western's customers was explored.

For the East Grid, this analysis concentrated on impacts to the Western Balancing Area transmission and potential flow constraints on the same transmission interfaces as the DWTS. For the West Grid, the study concentrated on the Montana transmission grid and flow interchanges to the south and west through flowgates of common concern to this area. The East and West flow interchanges through the DC interties were set to the same values and were based on historical Western schedules and the Western Area Coordinating Council's (WECC) 2007 Series base cases for the 2011 summer period.

The purpose of this summary is to briefly identify additions to the Western transmission system that may be necessary due to addition of the tribal wind projects based on power flow analysis.

Tribal Wind Project Transmission Interconnections

Candidate tribal wind projects are those projects identified by the Wind Demonstration Project Questionnaire (Questionnaire) completed by tribes interested in participating in the WHFS project (see Work Element 3).

Conceptual physical interconnections were developed for each site identified in the Questionnaire. Due to tribal-requested confidentiality, each tribe was supplied with individual specific site data documented on a map and sent to each tribe for verification. Results here provide no specific details. It is expected that specific tribal interconnection costs will be determined as part of development of specific site details and the interconnection application.

The following principles formed the basis for assumed transmission interconnections:

- Western transmission facilities physically available close to each site. All sites were assumed 115 kV interconnections where possible, with some connected at 161 kV and 345 kV.
- The Interconnection substation was configured to interface with available transmission voltage with a high-voltage substation configuration appropriate for available high-voltage network reliability.

To support the economic analysis, the following conceptual interconnection was developed as the basis for cost estimating.

A 115 kV interconnection as follows:

- 34.5 kV Collection Facility:
  - Radial feed substation and supporting equipment;
  - 50 MW wind generation plant with four 34.5 kV feeders entering from the wind turbines; and
  - One 115-34.5 kV transformer.
- 115 kV Transmission Line:
  - Line Length – Based on the individual site conceptual interconnections, a length of five and one-third (5.33) miles was used.
  - Single circuit 397.5 or 477 kcmil ACSR (Ibis) conductor per phase.
  - H-frame structures to match existing Western infrastructure in UGPR;
- 115 kV Interconnection:
  - An existing Western 115 kV main-transfer substation.
  - One 115 kV breaker and supporting equipment.

Table 2-7 summarizes the conceptual cost estimate for a typical tribal wind plant interconnection.

Table 2-7 Conceptual Cost Estimate
Typical Tribal Wind Plant Interconnection

Voltage	Average Length (Miles)	Transmission Line Cost* (397.5kcmil Ibis)	Typical Collector Sub Cost (34.5kV)	Typical Interconnection Cost (115 kV)	Total Interconnection Cost
115kV	5.33	$2,290,000	$4,450,000	$1,652,000	$8,392,000
* Transmission line cost does not include land, right-of-way, or tax costs					

East Grid

The PASS3 MRO 2008 Series 2010 Summer Peak Case, used in this study, was conditioned to reflect existing and proposed generation in Western's Balancing Area. DC ties were also adjusted to reflect high-load, high-transfer west-to-east condition. As this was a 2008 Series case, no transmission additions were included over and above those already identified by participating utilities.

Base Case

The new East Grid Base Case (BaseCaseEast) included the PASS3 MRO 2008 Series 2010 Summer Peak Case along with proposed 265 MW of Basin-owned and 300 MW of 5-year Western wind generation. The basic PASS3 interchanges were not adjusted except to reflect modifications in Western's Balancing Area. As Western generation was adequate to supply its modeled load requirements, the 300 MW of Western area wind projects were assumed to be sold to PJM East (Excelon). This serves to increase NDEX flows, which creates potential for highly-constrained flows, and serves as a worst case scenario. The Basin wind projects' outputs were supported by Basin generation requirements.

Tribal Wind Case

BaseCaseEast was modified with addition of a representative 50 MW tribal wind project at Yankton, South Dakota. Note that this project was selected as being representative only, and not as the project that may be selected for demonstration at a later date. The transmission study objective was to identify potential system constraints rather than specific multiple site requirements. Yankton was selected due to:

- **Location** – Central location within the proposed tribal sites.
- **Transmission Capabilities -** The Questionnaire listed Fort Randall as the proposed interconnection point for Yankton. The Fort Randall area has substantial existing transmission facilities which would minimize additional project-oriented transmission issues, so the conceptual interconnection approach could be used.

Analysis

Base case and tribal case load flows were executed including both base flows and N-1 contingency flows.

Contingency Analysis

Over 500 contingencies were reviewed. All facilities in the 14 adjacent areas were monitored in this study. Line Overloads were flagged as greater than 95 percent loading. The following was noted:

- Overloads:
  - Lines – One less in the Tribal Case versus the Base Case.
  - Transformers – One additional overload in Tribal Case.
- Voltages:
  - Undervoltages – Three additional in the Tribal Case versus the Base Case.

- Overvoltages – No changes.

The Base Case system overloads and voltage violations would have been addressed as part of the normal transmission analysis associated with wind generation projects that would be operational prior to any tribal project. No "new" overloads in the Tribal Wind Case exceeded 105 percent. Voltage Violations were flagged as below .95 pu or greater than 1.05 pu. No new violations were less than 94 percent or greater than 106 percent. All system violations flagged were found to be existing problems or minor system issues which were within MRO/NERC reliability criteria single contingency ratings.

The addition of 50 MW of wind to tribal lands at Yankton did not create new concerns in the system over those identified in the Base Case. Note that a violation was counted only once regardless of number of contingencies in which it occurred as it would need to be addressed in its entirety with any system changes.

Transmission Interfaces

Flows were monitored on the same three transmission interfaces as the DWTS (ABB, 2005):

- The North Dakota Export (NDEX) Interface.
- Each of the two 230 kV line from Watertown to Granite Falls.
- The 7 transmission lines from Ft. Thompson going east and southeast plus the 115 kV line from Bonesteel to Ft. Randall..

Flows on each of these interfaces are listed in Table 2-8. None of the interface ratings were exceeded.

Table 2-8 East Grid Transmission Interfaces

Interface	Rating (MW)	Base Case Flow (MW)	Tribal Case Flow (MW)
NDEX	1950	733.4	731.3
Watertown	850	308.2	311.8
Ft. Randall	1500	877.1	871.5

Source: Stanley Consultants Inc.

As no new issues that required modification were identified above those that would have to be addressed in the Base Case associated with the generation expansion, no additional East Grid facilities or modifications are required under study parameters.

West Grid

The West Grid UGPR base model used a base transmission load flow model developed by Western's transmission planning staff based on the 2007 WECC Series and modified by NorthWestern Energy.

Base Case

The new West Grid Base Case (BaseCaseWest) included Western's 2011 high summer transmission model. No additional facilities were included. Interchanges remained the same except scheduled interchange with BPA was used to support Miles City DC flows.

Tribal Wind Case

BaseCaseWest, was modified with addition of tribal wind projects. Two tribal wind projects totaling 89MW were proposed in the Questionnaire. Both were included due to:

- **Location –** One in eastern and one in western Montana, and both generally impacting the northern Montana transmission system.
- **Transmission Capabilities**
  - Fort Peck - The Questionnaire listed Wolf Point Substation as the proposed interconnection point for Fort Peck. Due to its physical location, the project could be connected to either the East or the West Grid. The West Grid was selected to more severely stress the West Grid and increase the potential of identifying overall grid issues.
  - Blackfeet - The 34.5 kV distribution line between Browning and Cut Bank as the proposed interconnection point for Blackfeet.
- **Interchange -** Similar to the Base Case, the BPA scheduled interchange was used to balance out the Montana UGPR system

Analysis

The base case and tribal case load flows were executed including both base flows and N-1 contingency flows.

Contingency Analysis

Over 500 contingencies were reviewed. All facilities in the following areas and zones were monitored in this study: MONTANA, WAPA U.M., WESTERN MONT, WY NO EA, and ZONEBH. Violation flags were set as in the East Grid. The addition of the tribal wind at Fort Peck and Blackfeet reveals similar N-1 contingency results.

- Overloads:
  - Lines – One additional in the Tribal Case versus the Base Case
  - Transformers – No change
- Voltages:
  - Undervoltages – Ten fewer in the Tribal Case versus the Base Case
  - Overvoltages – No changes.

The Base Case system overloads and voltage violations would have been addressed as part of the normal transmission analysis associated with wind generation projects that would be operational prior to any tribal project.

As in the East Grid, a violation was counted only once regardless of number of contingencies in which it occurred as it would need to be addressed in its entirety with any system changes.

West Grid performance is similar to the East Grid:

- **Voltage Violations –** No additional Tribal Case violations were below 94 percent or exceed 106 percent of nominal voltage.
- **Overloads -** Line and transformer overloads found in the Tribal Case versus the Base Case did not exceed 105 percent of rated capacity.

All West Grid Tribal case violations were found to be well within reliability criteria for single contingencies.

The addition of Blackfeet lowered under voltages existing in the system by supporting voltage around Cut Bank in northern Montana. As in the East Grid, no new issues that required modification were identified above those that would have to be addressed in the BaseCaseWest associated with the other generation expansion or load growth. No additional West Grid facilities or modifications are required.

Transmission Interfaces

The WECC 2008 Path Rating Catalog lists six (6) transmission interfaces in Montana. Each interface monitored in this study is listed as follows:

- Montana to Northwest.
- West of Broadview.
- West of Colstrip.
- West of Crossover.
- Montana-Idaho.
- Montana-Southeast.

None of the interface ratings were exceeded in either case.

As no new issues that required modification were identified above those that would have to be addressed in the Base Case associated with the generation expansion, no additional West Grid facilities or modifications are required.

Conceptual Transmission Investment

As described above, Table 2-7 provides the estimated conceptual transmission cost estimate for connection of each tribal wind site. As there are no transmission grid additions, the estimated East Grid transmission interconnection cost to be included in the WHFS analysis is $8,392,000.

Conclusions

The following conclusions are drawn:

- Analysis of the Western UGPR transmission grid required analysis of both the West and East Grid Western Balancing Areas.
- Power flow case analysis indicates that, although there are potentially significant numbers of overload and voltage issues associated with the added wind projects operational before the tribal projects are presumed to be energized, tribal project additions do not require overall grid additions over and above

those that would be needed for previous expansions. Tribal wind project overloads and voltage violations affect the same buses and branches as previous projects would.

- Transmission grid impacts are similar to those observed in the DWTS (ABB, 2005).
- This analysis does not take the place of Western Open Access transmission studies for tribal wind projects.

Work Element 5 – Assessment of UGPR Impacts

Legislation Objective – Section 2606 (b)(1) determine the economic and engineering feasibility of blending wind energy and hydropower generated from the Missouri River dams operated by the Army Corps of Engineers, including an assessment of the costs and benefits of blending wind energy and hydropower compared to current sources used for firming power to the Western Area Power Administration; and 3) … projected cost savings through a blend of wind and hydropower over a 30-year period.

The historical analysis (Work Element 2) and tribal wind assessment (Work Element 3) documented steps taken to develop definitions of the two wind scenarios: BaseWind (723 MW of existing and projected non-tribal wind in Western's Balancing Area), and TribalWind (Base plus a 50 MW tribal wind project for a total of 773 MW in Western's Balancing Area). These two scenarios were used in the transmission analysis (Work Element 4) to determine whether addition of the 50 MW of tribal wind projects created any transmission constraints that were not already on the system. [Note: Post 2015, the wind profiles for the 300 MW of 5-year contract wind were replaced by wind profiles for the tribal wind projects.]

These two wind scenarios were used in a series of power market simulations to evaluate economic and operational impacts of adding tribal wind energy to Western's system. Ventyx was retained to use its PROMOD IV simulation model to project Western's system operations over a 30-year period, starting in 2011. Ventyx used two distinct sets of power marketing simulations: 1) Zonal transmission modeling to evaluate the long-term economics of tribal wind integration, and 2) Nodal transmission modeling with more detailed representation included to evaluate how integrating tribal wind impacts the overall system operations and transmission constraints. The zonal modeling includes Western's generation from both Eastern and Western Interconnects, whereas nodal modeling only includes representation of the Eastern Interconnect, based on conclusions reached in Work Element 4.

Results from the nodal market simulation supplemented findings from Work Element 4 transmission system evaluation. Results from the zonal market simulation provided 30 years of energy costs for the two wind scenarios—BaseWind and TribalWind. These energy costs were used as inputs to an economic analysis to compare net present value of the two wind scenarios.

Case design for comparison was to create three hydro generation system levels for representative base, low, and high hydro generation years, and to provide the two wind scenarios described above within those hydro system levels. Table 2-9 shows the case design.

Table 2-9 Case Design for Economic Comparative Analysis

	LowHydro	**BaseHydro**	**HighHydro**
BaseWind (723 MW with 300 MW to serve Western load)	LowHydro with BaseWind	BaseHydro with BaseWind	HighHydro with BaseWind
TribalWind (773 MW with 350 MW to serve Western load)	LowHydro with TribalWind	BaseHydro with TribalWind	HighHydro with TribalWind

Representative hydro system levels follow criteria similar to that used in Work Element 2, when analyzing Western's historical data. The process used to determine single-year and 30-year data for the hydro generation levels is described later in this Work Element. Representative wind data for the BaseWind Case used a single year of wind power simulated data synchronized with a time-series of historical load data to represent the proposed generation mix for the UGPR through 2011. Since Western's load is not subject to growth projections, the same load/wind pattern was used for nodal simulations and each of the 30 years in the zonal simulations. The representative wind data for the TribalWind case used the same wind/load pattern, but included 50 MW of tribal wind in addition to the 723 MW that is expected by 2011. The process used to develop this single year wind/load pattern is described later in this work element.

Focus of the economic analysis was to determine how integrating tribal wind energy in Western's Balancing Area instead of historical power purchase practices (i.e., purchasing energy at market prices), would impact overall costs to Western's customers. Estimated values for Renewable Energy Credits (RECs) and Operation and Maintenance (O&M) expenses related to transmission interconnections for the tribal wind energy were added to system costs calculated through the zonal market simulations to provide net present value of Western costs for the Base and Tribal Wind cases. These net present value comparisons were calculated for the three hydro generation scenarios already described.

Total costs for the 30-year simulations, as well as average annual costs for the six cases outlined in the case design in Table 2-9, were analyzed to identify cost of a 50 MW Tribal Wind Demonstration Project to Western's customers. This comparison assumed 300 MW of the wind in the BaseWind case was serving Western load, and the additional 50 MW of tribal wind would create a total of 350 MW of wind serving Western load. An additional three cases for a ReferenceWind case were also used for comparison The ReferenceWind case was created to simulate the 158 MW of wind currently in Western's UGPR Balancing Area and provides a baseline for the PROMOD costs generated in the simulations.

Assumptions for PROMOD IV Power Market Simulations

In developing the power market simulations, Ventyx relied on its standard set of input assumptions for most of the data. See Appendix G for an outline of these assumptions. Data describing Western's system over the 30 year simulation period were customized including hydro generation and load patterns, as well as data describing projected wind resources and energy costs. These customized assumptions are described below.

Hydro-Generation Forecasts

As in the analysis of Western's historical load and generation data described in Work Element 2, three hydro generation scenarios were run for each wind scenario. Water forecasts were developed with the Corps for the three hydro-generation scenarios for both the zonal, 30-year simulation, and the nodal, single-year, 2011 simulation. Forty years of Upper Missouri River system historical generation data was used to simulate three periods that represented 30 years of high hydro generation (i.e., 30-year average generation between the upper quartile and decile for the last 40 years), 30 years of base hydro generation (i.e., 30-year average at the median), and 30 years of low hydro-generation (i.e., 30-year average between the lower quartile and decile). These hydro scenarios were discussed and finalized with the Project Team. A summary of the data used for the models is indicated below. It was assumed that all available hydro generation was dispatched to meet load prior to using wind energy.

Zonal-30-Year Hydro-Generation Scenarios

Low Hydro Generation-Years 1998-2007 repeated 3 times. Average annual generation = 7.838 billion KWh

Base Hydro Generation-First 30 years (1967-1996) from the last 40 (1967-2006) years of operational data available from the Corps. This includes 6 drought years and the 2 wettest years on record, 1978 and

1993. Average annual generation = 10.265 billion KWh. Note that generation from Reclamation dams are added to the Corps's data in all three hydro simulations for a slightly higher generation total.

High Hydro Generation-Years 1967-1976 repeated 3 times = Average annual generation = 12. 068 billion KWh

Nodal Single-Year 2011-Generation Scenarios

The Corps used a process similar to the statistical assessment for the Annual Operating Plans to determine hydro generation years that would be appropriate for use in the nodal market simulations.

Base Hydro Generation -The Corps currently has median, lower decile, and lower quartile projections through 2011. This 2011 median number was used to identify a year with comparable total year hydropower generation for use as the 2011 base case. The representative year chosen was 2000, with 10.211 billion kWh from Corps projects. [Note: Once the representative years were identified, generation from the Reclamation dams were included in all three hydro scenarios as part of the 30 year market simulation data.]

High Hydro Generation -The Corps generated an upper decile simulation that was used for the 2011 high hydro generation year. A year with a comparable total year hydropower generation was used for the high hydro generation run. The representative year chosen was 1997 with 15.267 billion kWh from Corps projects.

Low Hydro Generation –The Corps modified the lower decile projection currently run for 2011, by adding a low decile year (15.5 MAF) in at 2010 to minimize the "trend back to normal" typically encountered in five year runs. A year with comparable total year hydropower generation was used for the low hydro generation run. The representative year chosen was 2007 with 5.744 billion kWh from Corps projects.

Peaking Returns

As discussed in Work Element 2, peaking return contracts allow the contract holder to return on-peak energy used during off-peak hours. There are three peaking contracts currently in place with Western's customers. Actual returns from these contracts were analyzed to determine a monthly average off-peak hourly return MW value to include in the PROMOD simulations. Peaking return energy used for market simulations were a constant 9,747,000 MWh for a 30-year total or an average of 324,900 MWh annually. Note these returns do not occur every month.

30-Year Load and Wind Forecasts

Typically, in wind integration studies, wind energy is considered an energy resource instead of a capacity resource. Wind energy is subtracted from the load pattern, not added to the generation capacity pool. Therefore, matching load and wind generation patterns is critical.

To populate the PROMOD IV cases, a single-year wind/load pattern was repeated for 30 years for the BaseWind case; the TribalWind case utilized the same wind profile, but added 50 MW of tribal wind. As indicated in Work Element 2, Western's load pattern shows very little variation over time. In addition, the Wind Integration Study performed for Western indicated that there was no correlation between water runoff years and wind data (Zavadil, 2006). Hence, a representative load/wind year using Western historical load data and 3TIER simulated wind energy for the year 2000 was used.

As described in Work Element 3, 3TIER provided wind data for calendar year 2000 for all proposed WHFS wind sites (non-tribal and tribal). Locations for the non-tribal proposed sites were provided by Western from the site developers. Stanley Consultants provided latitude and longitude for all wind sites to 3TIER. No attempt was made to optimize (micro-siting) site wind speed potential. The GE1.5 SLE power curve was used for all wind energy production estimates. As with the tribal data, the non-tribal wind data provided by 3TIER establishes a representative profile for the proposed sites to be used in PROMOD IV market simulations. It is not intended for use as a metric for energy potential in the region. The 3TIER Inception Report is in Appendix D.

Wind data for the existing sites was available starting in fall of 2006; calendar year 2007 data was used for existing wind sites. Although mixed wind data is not ideal for the analysis, all scenarios used the same wind/load combinations and hence, were comparative. No findings from simulations were used to calculate a definitive number. Findings were used to compare costs identified between the BaseWind, TribalWind and ReferenceWind cases within one of the three hydro generation scenarios.

Reserve Requirements for Wind Penetration Levels

Since both BaseWind and TribalWind scenarios are relying on wind penetration levels greater than 20 percent, EnerNex was retained to perform a sub-hourly analysis to determine how Western's regulation and load following reserve requirements would be affected by these wind penetration levels. Results from this analysis were used to account for additional reserve requirements in the market simulations The analysis used high resolution (30 second and 10 minute) load and (existing) wind energy production data provided by Western. Synthesized wind energy production data at 10 minute intervals for the same historical year as the archived Western data was developed by 3TIER. The full sub-hourly report, "Description of Regulating Reserve Estimation Methodology" can be found in Appendix E.

In most wind integration studies, this sub-hourly analysis is central to the conclusions regarding costs of integrating wind. However, regulation and load following reserve requirements for this study simply provided a proxy for accounting in the market simulations. Costs related to reserve requirements are not directly called out in the market simulation results, but incorporated in overall costs of simulated values.

The analysis looked at reserve requirements for regulation (i.e., short time scales measured in seconds), load following with perfect knowledge of the next hour requirements (10 minutes to several hours), and additional reserves required to cover incremental forecast errors. The load following requirement with forecast error assumed a "persistence" forecast for wind generation—the forecast for the next hour is simply what was delivered in the current hour.

Wind configurations used for the analysis included:

- Existing Wind incorporating 158 MW of wind currently in the Balancing Area,
- Base Wind adding 265 MW of additional wind and 300 MW of five-year, non-tribal wind for a total of 723 MW or 23 percent penetration on the Balancing Area, and
- Tribal Wind which adds 50 MW of tribal wind for a total of 773 MW or 25 percent penetration on Western's Balancing Area.

Conclusions from this sub-hourly analysis were similar to other studies. The fast regulation capacity necessary for Western's Balancing Area was not appreciably influenced by amounts of wind generation in the range of penetration levels considered (23 percent and 25 percent). Similarly, the load following requirements, if system operators had perfect knowledge of the next hour average load and wind generation, does not represent large additional requirements. Average hourly values for these additional operating reserves are included in Table 2-10.

Table 2-10 Estimated Load Following Requirements for Western Load and Wind Scenarios 98 Percent CPS2 Performance—Perfect Short-Term (Hour Ahead) Forecasting

Scenario	Average	Maximum	Standard Deviation
Load Only	0.0 MW	0.0 MW	0.0 MW
Existing Wind (158 MW of wind)	18.5 MW	36.0 MW	9.7 MW
BaseWind (723 MW of wind)	28.0 MW	40.0 MW	10.3 MW
TribalWind (773 MW of wind)	29.4 MW	42.4 MW	11.0 MW

It is the uncertainty in the wind forecast that increases reserve requirements for higher wind penetrations. Average hourly requirements with this added uncertainty are shown in Table 2-11. Here, the impact of short-term wind generation forecast errors is fairly significant. Results from this analysis were used as input to the reserve categories in PROMOD IV and carried forward as constraints in the annual production simulations.

Table 2-11 Estimated Load Following Requirements for Western Load and Wind Scenarios 98 Percent CPS2 Performance— Load Following Requirement with Forecast Error

Scenario	Average	Maximum	Standard Deviation
Load Only	0.0 MW	0.0 MW	0.0 MW
Existing Wind (158 MW of wind)	18.5 MW	36.0 MW	9.7 MW
BaseWind (723 MW of wind)	73.5 MW	105.0 MW	27.0 MW
TribalWind (773 MW of wind)	77.2 MW	111.3 MW	28.9 MW

Values in Tables 2-10 and 2-11 assume that Western's Balancing Area performance, as measured by the approximate CPS2 metric used in these calculations, remains as for load alone, at 98 percent. This CPS2 metric is very high compared to other balancing areas in the country. It is expected that relaxing this performance level would decrease reserve requirements for wind generation slightly. A recent study done for NorthWestern Energy's electric system operation found that for higher wind penetration levels, further increase in wind power penetration resulted in lower CPS2 ratings. Although wind power forecasting mitigated some impacts of higher wind power penetrations, additional regulating reserves were required to maintain CPS2 compliance in most scenarios (GENIVAR, 2008).

Table 2-12 displays average hourly values for additional operating reserves required for a 95 percent CPS2 assumption. See Appendix E for the mathematical and statistical analysis used to derive these values.

Table 2-12 Estimated Load Following Requirements for Western Load and Wind Scenarios

95 Percent CPS2 Performance--Load Following Requirement with Forecast Error

Scenario	Average	Maximum	Standard Deviation
Load Only	0.0 MW	0.0 MW	0.0 MW
Existing Wind (158 MW wind)	18.5 MW	36.0 MW	9.7 MW
Base Scenario Wind (723 MW wind)	42.0 MW	60.0 MW	15.4 MW
Tribal Scenario Wind (773 MW wind)	45.2 MW	65.2 MW	16.9 MW

Cost of Energy-Wind and Hydro

In determining the final cost estimate for purchasing wind energy from tribal installations, two different industry-accepted Wind Project Calculators were used for comparison purposes. One was the Community Wind Toolbox provided by Windustry.com. The calculator is described as "*a tool for basic financial analysis that developers can use at the beginning of the project planning process*." The other calculator was the

WindFinance Tool from NREL. This application is described as "*an on-line levelized cost of energy calculator for wind energy projects*." Each calculator was run for two cases, once accounting for the federal Production Tax Credit (PTC), and a second time assuming no federal PTC.

The Project Team agreed on assumptions used in determining the values that were entered into the calculator. Cost of tribal wind energy value used in the PROMOD simulations needed to be a realistic representation that would be marketable for Western, as well as provide a reasonable return on investment for the tribes. An energy cost estimate of $0.05/kWh was used for wind energy, and includes the PTC. This cost of energy does not include tribal wind REC valuation, but REC was included separately in the economic analysis conducted after the PROMOD simulation was completed.

The energy cost estimate did not include capital costs for transmission interconnection. For the Yankton demonstration project, capital cost indicated in Work Element 4 of $8.4 million would require an addition of approximately 4.5 mills for a cost of energy of $0.0545/kWh. This capital cost was not included in the cost of energy for production simulations since specific site requirements, financing arrangements and contractual terms with Western will determine these values. It is expected that the proposals for Tribal Wind Demonstration Projects will be considered in the selection process to be determined outside of this study.

Carbon Penalty Legislation

In accordance with discussions with the Project Team, the market simulation forecasts in this study assume that a form of greenhouse gas emission reduction policies will be enacted within the study timeframe. In developing the assumptions underlying those policies, a series of studies were examined that looked at projected prices for tradable CO_2 emissions allowances. A composite view on projected CO_2 prices was developed for this study. See Appendix G for more information on carbon penalty assumptions.

Results from PROMOD IV Market Simulations

Nodal results

The results from the nodal market simulations follows:

- The addition of the wind plants does not constrain any flowgates that were not already constrained. This applies both to the base wind versus the reference wind and to the tribal wind versus the base wind.
- There is not a significant increase in the amount of binding hours on any flowgates that were constrained in the reference or base case.
- There is no significant risk of wind curtailment due to transmission in any of the wind cases – even when the hydro-electric generation levels are high.

The nodal scenarios included monitoring of 68 interfaces and over 500 contingencies, plus numerous base case monitored branches, based on the NERC and MISO books of flowgates and other published sources and studies. Table 2-13 shows the number of hours monitored flowgates were binding in the nodal scenarios. Most of the flowgates had similar numbers of hours binding across all scenarios, but some do show some differences that are related primarily to hydro conditions rather than addition of the tribal wind.

Table 2-13 Monitored Flowgate Binding Constraints-Number of Hours

	Scenario						
Flowgates	RefWind BaseHydro	BaseWind BaseHydro	BaseWind HighHydro	BaseWind LowHydro	TribalWind BaseHydro	TribalWind HighHydro	TribalWind LowHydro
PR ISLD3 REDROCK3 2 (Contingency)	1	1		2	1		1
BYRON 5 MAPLE LF 1 (Contingency)	3	4	15	1	11	16	1
WALDO 7 SLVRBYH7 1 (Basecase)	1049	1046	1103	1168	1166	1099	1171
COAL TP4 COAL CR4 1 (Contingency)	789	709	644	1125	817	634	1111
COAL TP4 STANTON4 1 (Contingency)	3511	3665	3278	2717	3002	3284	2737
CBLUFFS5 AVOCA 5 1 (Contingency)	12	11	9	6	6	7	3
PLYMOTH5 SIOUXCY5 1 (Contingency)	548	366	180	734	322	176	722
MORNSD 5 PLYMOTH5 1 (Contingency)	14	7		84	8		77
HILLS 3 HILLSIE5 1 (Contingency)	1	2			1		
HILLS 5 PARNEL 5 1 (Contingency)	56	62	75	57	60	79	56
TIFFIN 3 ARNOLD 3 1 (Contingency)	29	24	20	49	30	19	50
DAVNPRT5 E CAL T5 1 (Contingency)	67	66	68	58	65	68	63
GENTLMN3 REDWILO3 1 (Contingency)	323	387	628	305	407	638	307
SHELDON7 20&PIO 7 1 (Contingency)	1	1		1	1		1
S1226 5 TEKAMAH5 1 (Contingency)	896	650	425	841	603	406	823
GR ISL1T GR ISLD4 1 (Contingency)	25	29	156	2	31	160	2
LELANDO3 LELND2TY 1 (Contingency)	480	551	455	399	510	455	415
CASVILL5 NED 161 1 (Contingency)	1	3	8	6	8	9	7
GENOA 5 COULEE 5 1 (Contingency)	744	722	659	797	739	659	795
ALMA 5 WABACO 5 1 (Contingency)	1	1	3		1	3	
INTERFACE NDEX	913	895	930	964	1081	928	945
INTERFACE Ft Thompson	0	0	0	0	0	0	0
INTERFACE Watertown - Granite Falls	0	0	0	0	0	0	0

Economic Analysis Results

Net costs to Western from zonal results were inputs into an economic analysis that discounted the values from the 30-year simulations into net present value (NPV) in 2011 dollars. A 5 percent discount rate was used for this analysis, based on the Office of Management and Budget report (Circular No. 94, released January 2008). These costs are a function of assumptions embedded in the PROMOD IV model about both technology development and market conditions outside the Western Balancing Area. A formal sensitivity analysis of those assumptions is outside the scope of this study. The following analysis first looks at the NPV for the REC and transmission O&M costs that would be incurred for a Tribal Wind Demonstration Project. The analysis then shifts to NPV for the ReferenceWind case. These values provide a baseline cost to represent current Western operations. This value is the *PROMOD dollar* equivalent to what Western operations currently cost its members. Next, the analysis compares the Reference Wind case to the BaseWind and TribalWind cases for all three hydro scenarios. This provides the relative costs for Western operations when adding 300 MW of wind to serve its load and 350 MW of wind to serve its load. Finally, the analysis looks at the difference between the BaseWind and TribalWind cases to determine a cost for adding the 50 MW of tribal wind. As seen in the analysis, costs associated with the incremental 50 MW of tribal wind shows diminishing savings for Western's customers. [Note: All dollar values used in cost comparisons are in NPV 2011 dollars.]

REC and O&M Costs for 50 MW Tribal Wind Demonstration Project

REC values were included in this analysis, as were costs associated with O&M for the tribal wind transmission interconnection (based on the Work Element 4 transmission investment.). Appendix H presents a summary of Economic Analysis assumptions. The capital cost of $8.4 million for interconnection for the tribal wind energy injection was used (See Work Element 4, Table 2-7). REC value was assumed to start at $5/MWh with a 5 percent annual escalation. O&M for the interconnection was assumed to be 10 percent of capital costs with a 4 percent annual escalation. The NPVs for the 6 cases are shown in Table 2-14.

Table 2-14 30-Year Summary Comparison of BaseWind Cases with TribalWind Cases for Three Hydro Generation Scenarios Net Present Value (2011 k$)

	BaseWind	TribalWind
LowHydro		
Net Present Value Costs Only	$5,983,030	$5,981,847
Net Present Value Costs with RECs & Transmission O&M	$5,983,030	$5,978,111
BaseHydro		
Net Present Value Costs Only	$4,589,942	$4,601,929
Net Present Value Costs with RECs & Transmission O&M	$4,589,942	$4,598,192
HighHydro		
Net Present Value Costs Only	$3,496,623	$3,521,275
Net Present Value Costs with RECs & Transmission O&M	$3,496,623	$3,517,539

As seen in Table 2-14, the 30-year NPV of the RECs and O&M costs equals an estimated $3.7 million in savings for the TribalWind case in all three hydro scenarios ($123,000 average annual savings). REC values and transmission O&M costs were not estimated for the 300 MW 5-year wind contract since it is just the differential for the Tribal Wind Demonstration Project that is of interest for this study. System upgrades required to interconnect the 723 MW of non-tribal wind in the UGPR Balancing Area were assumed to be part of the developer's costs and not included in this analysis.

The $3.7 million in net savings for the TribalWind scenario used in the three hydro scenarios does not change with hydro generation. Since no additional transmission constraints were identified as a result of the injection of the 50 MW of tribal wind in the power flow analysis, no system upgrade costs were included for the TribalWind scenario. The wind energy generated for the TribalWind case is constant for the low, base and high hydro cases. The O&M costs are also constant for all three hydro scenarios. The $8.4 million capital cost assumes a length of 5.33 miles for one interconnection, that is the same value used in all three hydro cases.

Given these conditions, the value saved from the REC payments is greater than the transmission O&M costs resulting in a net savings over the 30 year period. The net value is dependent on the assumptions made for the REC market value and the length and number of interconnection lines and may not always result in a net savings. For example, if two 25 MW tribal wind projects were connected at 5 miles each instead of one 50 MW project, the transmission O&M costs would double. If a REC value of $2.5/MWh were assumed instead of the $5/MWh used in this analysis, these REC savings would be cut in half. Since this net value (of REC savings and transmission O&M costs) is a constant number that can be added to each case, and the value can be adjusted depending on the assumptions made, only the NPV costs generated from the market simulations (excluding the RECs and transmission O&M costs) will be considered when comparing cases.

ReferenceWind Comparisons with BaseWind and TribalWind Cases

Table 2-15 shows the NPV for the three hydro scenarios with three wind scenarios—BaseWind, TribalWind and ReferenceWind. The ReferenceWind case was included in the zonal market simulations to provide a baseline cost for current Western operations. This case includes only 158 MW wind that is in the UGPR Balancing Area, but does not serve Western's load. The dollar value generated from the market simulation gives the PROMOD solution to Western's current purchase needs. The BaseWind case was the design case to represent the wind resource mix in the UGPR Balancing Area for the 30 year zonal run from 2011 through 2041. This case includes 423 MW of wind that is in the Balancing Area, but not serving Western's load and 300 MW of five-year contract wind that is serving Western's load. The third wind scenario, the TribalWind case, was the design case to represent the wind resource mix in the UGPR Balancing area for the 30 year zonal run assuming a Tribal Wind Demonstration Project is included. This case includes 423 MW of wind that does not serve Western load, and 350 MW of wind that serves Western's load including 300 MW five-year contract wind and 50 MW for a Tribal Wind Demonstration Project.

Reviewing the costs for the ReferenceWind cases—the costs Western's customers are currently experiencing in *PROMOD dollars*—shows costs ranging from a low of $3.4 billion for 30 years ($116 million average annual costs) for a high hydro generating year to a high of $6.1 billion for 30 years ($203 million average annual costs) for a low hydro generating year. The deviation around the base hydro generating case indicates that a low generation year costs Western's customers around $1.5 billion for the 30 year simulation ($4,631,137,000 - $6,093,513,000) or an average of $49 million annually; a high generation year saves Western's customers around $1.2 billion for the 30 year simulation ($4,631,137,000 - $3,475,429,000) or an average of $38 million annually.

Table 2-15 NPV Cost Comparison between Three Hydro Scenarios and Three Wind Scenarios Net Present Value (2011 k$)

	Reference Wind Western PROMOD Costs for Existing Operations	BaseWind Western PROMOD Costs with 2011 Wind Mix	TribalWind Western PROMOD Costs with 2011 Wind Mix and Tribal Wind Demonstration Project
Existing wind (MW)	158	158	158
Proposed wind (MW)	0	265	265
Wind Serving Western Load (MW)	0	300	350
Total Wind Nameplate (MW)	158	723	773

				Savings Over Reference Case		
				Reference - Base	Reference - Tribal	Base – Tribal Comparison
	(A)	(B)	(C)	(A-B)	(A-C)	(B-C)
LowHydro						
NPV Total 30 Year Costs	$6,093,513	$5,983,030	$5,981,847	$110,482	$111,666	$1,183
NPV Annual Average	$203,117	$199,434	$199,394	$3,683	$3,722	$39
BaseHydro						
NPV Total 30 Year Costs	$4,631,137	$4,589,942	$4,601,929	$41,195	$29,208	($11,986)
NPV Annual Average	$154,371	$152,998	$153,397	$1,373	$973	($400)
HighHydro						
NPV Total 30 Year Costs	$3,475,429	$3,496,623	$3,521,275	($21,194)	($45,846)	($24,652)
NPV Annual Average	$115,848	$116,554	$117,376	($706)	($1,528)	($822)

Costs experienced by Western's customers during a low generation year are a result of purchasing energy on the spot market to cover Western's load obligations. The savings during a high hydro generation year are revenues generated from selling excess hydro generation on the market. Negotiating contracts to provide energy instead of short term purchases should reduce the costs of spot market purchases during low hydro generation years. Assuming the contract price of energy is less than the spot market price for energy, cost savings will occur when contracted energy is used instead of purchased energy; sales revenues will be generated when contracted energy is sold at market prices over the contracted cost for energy. Any non-hydro energy contract would probably include a cost of energy at amounts higher than Western's hydro generated energy. This study is not comparing the difference between contracted energy and hydro energy—it is considering the cost difference between contracted energy and the spot market price incurred when purchases are needed to cover load obligations.

Table 2-16 highlights the comparison of the costs for the BaseWind and TribalWind cases with the ReferenceWind case (as shown in Table 2-15 columns A-B and A-C). The table shows that during a low hydro generating year, the BaseWind case saves Western's customers $110 million dollars and the TribalWind case saves them $112 million over the 30-year simulation period or about $3.7 million average cost savings annually for 30 years. During a base or median hydro generating year, the table also shows that Western's customers save an average of $1.4 million annually in the BaseWind case and almost $1 million on average annually for the TribalWind case ($41 million and $29 million). Here, the TribalWind savings is not as much as the BaseWind savings. This indicates that the additional 50 MW of tribal wind either does not reduce spot market purchase costs, or that wind energy sales are not generating revenue. The cost comparison for the high hydro generating year indicates that both the BaseWind and TribalWind cases cost Western's customers an average $706,000 and $1.5 million respectively ($21 million and $45 million for 30-year totals). If adding additional wind energy to Western's Balancing Area costs Western's customers more than the existing or reference case during a year when very few purchases are made, the wind energy being sold is not generating revenue.

Table 2-16 Comparison of Western Customer Costs for BaseWind and TribalWind Compared to ReferenceWind Cases Net Present Value (2011 k$)

	Reference - Base	Reference - Tribal
LowHydro		
NPV Total Costs Savings(Costs) from Reference Case	$110,482	$111,666
NPV Annual Average Savings(Costs) from Reference Case	$3,683	$3,722
BaseHydro		
NPV Total Costs Savings(Costs) from Reference Case	$41,195	$29,208
NPV Annual Average Savings(Costs) from Reference Case	$1,373	$973
HighHydro		
NPV Total Costs Savings(Costs) from Reference Case	($21,194)	($45,846)
NPV Annual Average Savings(Costs) from Reference Case	($706)	($1,528)

TribalWind and BaseWind Comparisons

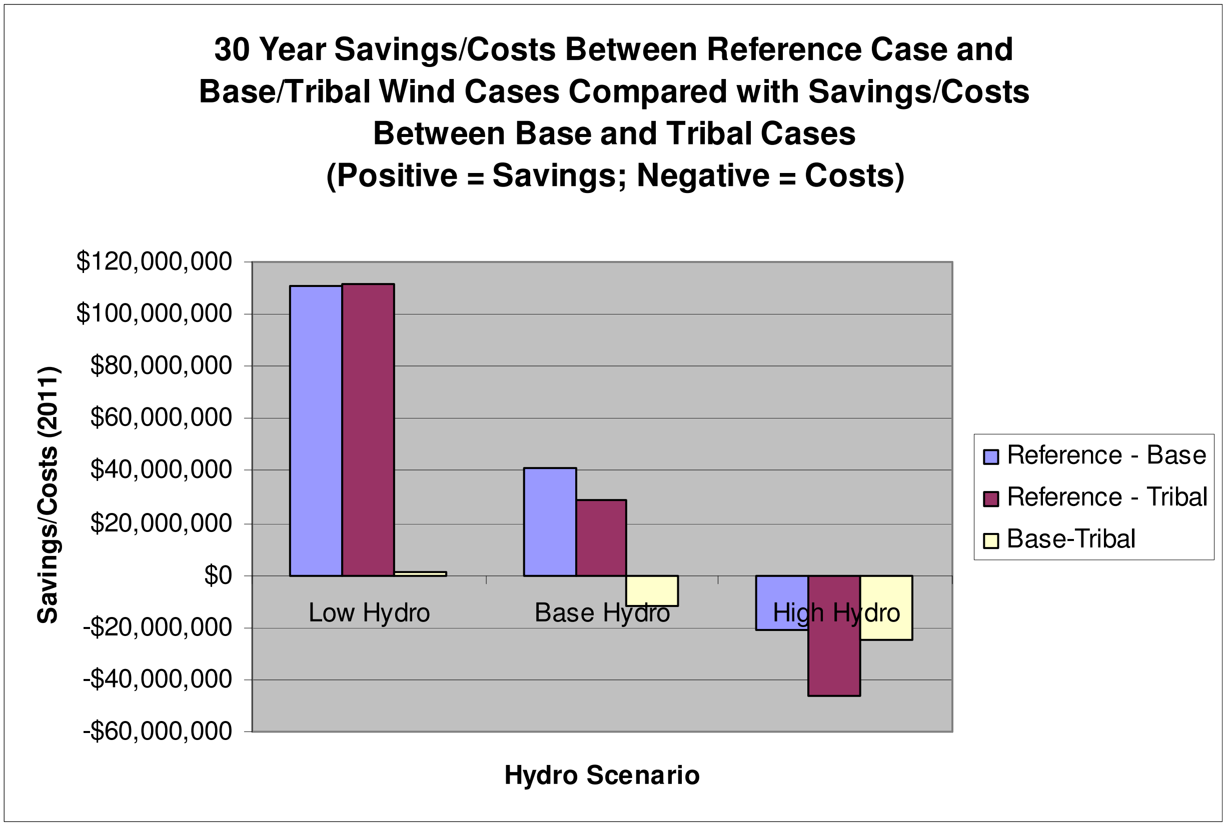
Finally, comparison between the BaseWind and TribalWind cases for the three hydro scenarios is displayed in Table 2-17 (as shown in Table 2-15 column B-C). Here, only the LowHydro case shows a savings to Western's customers for the additional 50 MW of tribal wind. Both the BaseHydro and HighHydro scenarios show that adding tribal wind to the 723 MW of wind in the UGPR Balancing Area, does not save Western's customers money, but has a 30-year cost of $12 million ($400,000 average annual) and $25 million ($822,000 average annual), respectively. These costs are incurred when adding 50 MW of tribal wind to the UGPR Balancing Area that already has 723 MW of wind.

Table 2-17 NPV Comparison Between BaseWind and TribalWind Cases for Three Hydro Scenarios Net Present Value (2011 k$)

Hydro Scenario	Base – Tribal Comparison
LowHydro	
NPV Total Savings(Costs)	$1,183
NPV Annual Average Savings(Costs)	$39
BaseHydro	
NPV Total Savings(Costs)	($11,986)
NPV Annual Average Savings(Costs)	($400)
HighHydro	
NPV Total Savings(Costs)	($24,652)
NPV Annual Average Savings(Costs)	($822)

These BaseWind minus TribalWind costs give an indication of relative costs/savings when adding the incremental 50 MW of tribal wind to serve Westen's load. These differentials show that only the LowHydro generating case saves Western's customers money when adding 50 MW of tribal wind to the 300 MW already serving Western load. These BaseWind minus TribalWind costs ($822,000 for the HighHydro and $400,000 for the BaseHydro cases) are less than a quarter of the savings achieved with either the BaseWind or TribalWind cases as compared with the ReferenceWind case during a LowHydro year.

Figure 2-23 shows these costs compared to savings/costs incurred when adding 565 MW of wind (265 MW proposed wind plus 300 MW mid-term contract Western wind) to the ReferenceWind case to create the BaseWind case (for a total of 723 MW of wind) [Reference – Base in Figure 2-23] and when adding 615 MW of wind (265 MW proposed wind plus 300 MW five-year contract and 50 MW of tribal wind to serve Western load) to the ReferenceWind case to create the TribalWind case (for a total of 773 MW of wind--Reference-Tribal in Figure 2-23).



NPV Total 30-Year Costs Between Reference Case and Base/Tribal Wind Cases Compared with Savings/Costs Between Base and Tribal Cases
Figure 2-23

These findings suggest that there may be an *economic saturation for wind energy* used to meet Western's load within the pricing assumptions used in these marketing simulations. This is not a definitive number. Further work will be needed that focuses on determining an economic saturation point for wind energy for Western's ratepayers. This work could identify conditions that influence a saturation point for wind energy.

As discussed in Work Element 2, the Purchase Capacity Bandwidth provided a range for energy purchases to be used to meet Western's load obligations instead of spot market purchases. Maximum value of this range, 333 MW capacity, converted to 816 MW of wind nameplate (calculated in Work Element 3 using a 40.8 percent capacity factor). This wind nameplate value was adjusted down to 773 MW (to fall within a 25 percent wind capacity penetration on the UGPR Balancing Area) for use in the market simulations. This maximum value of 773 MW might need to be reduced given the *economic saturation of wind energy* that appears to have been reached in the market simulation.

Reviewing Western purchases shown in Figures 2-3 through 2-5, when deciding on a range for the Purchase Capacity Bandwidth initially, the challenge was the risk associated with adding wind energy during a high hydro generation year when excess (surplus) occurs. Contracting for additional wind energy, whether it is tribal wind or non-tribal wind, to meet Western's load during low generation years is an easy economic decision. As shown in the market simulations, wind energy was used to meet load and reduced the costs associated with additional purchases typically encountered during low generation years. Even during the BaseHydro scenario, which represents 19 out of the last 39 years (see Figure 2-2), the economic benefits when using 350 MW of wind to serve Western's load are evident with $29 million savings over the 30-year period as compared with Western's current generation mix. It is the high generation years that account for 10 out of the last 39 years (Figure 2-2), with potential costs up to $1.5 million per year (Table 2-16), when using 350 MW (including 50 MW of tribal wind) to serve Western's load that pose the economic risk for Western's customers.

Costs incurred during the HighHydro scenario increase from $700,000 average annual costs for 300 MW of wind used to meet Western's load to $1.5 million average annual costs for 350 MW of Western wind. The BaseHydro scenario shows a similar trend with decreased savings achieved for Western's customers—the BaseWind case with 300 MW of Western wind saves $1.4 million per year and the TribalWind case, with 350 MW of Western wind saving less at $1 million per year (see Table 2-16). Results from these scenarios suggest that the incremental amount of wind contracted to serve Western's load above 300 MW may increase the economic risks to the Western's customers. Cost of a 50 MW Tribal Wind Demonstration Project may depend on how much wind is already being used to serve Western's load.

In order to reduce this economic risk, an amount of wind at 300 MW or less might produce a more optimal *economic wind integration* level to meet Western's load. Although the 300 MW of 5-year contract wind was included in the 30-year simulations as tribal wind after the term expired in 2016, Western may consider reducing the amount of total wind contracted after the 5-year contract expires to an amount that produces a more optimal economic benefit.

Economic risk will also be influenced by length of contract term. Market simulations for this study were performed over a 30-year period and used generation scenarios that would magnify the impacts for that scenario assumption. For example, the HighHydro scenario was run with generation levels that averaged above the upper quartile for the Missouri River System's 40-year history. This exaggerated scenario was not expected to provide a realistic projection for 30 years, but to show a worst case for high generation, excess (surplus) conditions. The LowHydro scenario was designed to exaggerate the low generation average to fall below the lower quartile. Projected costs/savings from these extreme hydro conditions over a 30-year period are not expected actual outcomes, but would be muted by the historical cycle of high/low runoff in the Missouri River System. Historically, drought and high runoff years cycle through 5 to 7 year periods (see Figure 2-2).

Negotiating wind energy contracts (either tribal or non-tribal) for a 30-year term might have unacceptable economic risks. The ability to predict runoffs over that length of time is difficult. Shortening the contract term could reduce economic risks associated with costs/savings expected during high and low generation years. Similarly, wind energy contracts that assume more than 300 MW of nameplate wind energy to meet Western's load over a variety of hydro conditions might present unacceptable economic risks for Western's customers. Based on assumptions described in this economic analysis, contracts for total nameplate wind energy of 300 MW or less are likely to result in more optimal *economical wind integration* for Westerns' load obligations.

Case Run without Carbon Penalty

An additional zonal case to estimate impacts of no CO2 penalty legislation was simulated. Results are shown in Table 2-18. The cases with a carbon penalty are actually less costly than the cases without a carbon penalty. Although carbon legislation is expected to be enacted by 2012, this comparison provides an indication of proportional impact of those carbon penalties between the BaseWind and TribalWind cases. As seen previously, the TribalWind case cost $12 million more than the BaseWind case in the BaseHydro scenario that incorporated carbon penalties ($4,602 million - $4,590 million seen in Table 2-17 without REC and transmission O&M costs included). But, the case with no carbon penalties cost more than the case with carbon penalties for the BaseHydro scenario for both wind cases BaseWind and TribalWind by about $1.2 billion for 30 year total (Table 2-17)—a similar magnitude difference as was seen between hydro scenario cases.

The impact of carbon penalties in these cases provides a cost savings to Western of a magnitude greater than the cost increase of adding 50 MW of Tribal Wind to Western's Balancing Area. This is expected since Western's hydro generation does not have a penalty, and selling it into a carbon penalty market would be advantageous. Most Western energy purchases are at a place in the cost curve where CO2 penalties are less severe. However, net costs increase slightly with the extra 50 MW of Tribal wind, suggesting that the full benefit of CO2 for the extra wind may be offset by less revenue from sales of wind energy.

Table 2-18 Comparison of BaseHydro BaseWind and TribalWind with CO2 Penalties to BaseHydro BaseWind and TribalWind without CO2 Penalties

		BaseHydro BaseWind No C02	BaseHydro BaseWind With CO2	BaseHydro TribalWind No C02	BaseHydro TribalWind With C02
PRESENT VALUE COSTS (2011)					
NPV Costs	(k$)	**$5,777,891**	**$4,589,942**	**$5,820,099**	**$4,601,929**
NO C02 Minus With C02	(k$)		**$1,187,949**		**$1,218,170**

Note: Present value shows approximately $1.2 billion more costly with No CO2 for 30 years or $40 million annually

MISO/SPP Analysis

Concurrent with the Wind Hydro Feasibility Study, Western is engaged in evaluating the possibility of joining one of the nearby Independent System Operators - Midwest ISO (MISO) or Southwest Power Pool (SPP). Joining an ISO offers many benefits, but proposed arrangements must be evaluated analytically and systematically in order to determine the full set of costs and benefits. As such, Western is employing similar study techniques as the WHFS and investigating the possible outcomes of being a member of an ISO during varying water conditions.

Regardless of how Western investigations into ISO membership turn out, it is possible to make some generalizations about Westerns operations with wind resources as part of its portfolio. As explained in the APPENDIX E discussion of Regulating Reserve Estimation Methodology, increased variability of the load net of wind for the Balancing Area can be determined and used to estimate increased incremental operating reserve requirements. Since the calculation is performed using the load with wind netted out, it stands to reason that the larger the load component, the less effect a given amount of wind would have on its variability. It can be safely assumed that if Western joins an ISO, the amount of wind being discussed in this study should be easier to manage and require less incremental reserves than if Western remains a stand-alone Balancing Area. Although SPP and MISO have different operating characteristics, the larger markets represented by membership in either would have a similar impact on wind integration. Applying this concept to this study, it should be expected that becoming part of a larger balancing area would be conducive to increased penetrations of Tribal Wind in the Western portfolio. [Note: Results from the MISO/SPP analysis study will be released in a separate document. None of the qualitative results from that study have been incorporated into this report.]

Section 3

Combined Wind and Hydro Impact on Reservoir Fluctuation

Legislative Objective – Section 2606 (c)(2) an economic and engineering evaluation of whether a combined wind and hydropower system can reduce reservoir fluctuation, enhance efficient and reliable energy production, and provide Missouri River management flexibility

The Missouri River Basin Water Management Division (MRBWMD) of the Corps directs the regulation of the Missouri River Mainstem Reservoir System (System) to serve the Congressionally-authorized project purposes of flood control, navigation, hydropower generation, irrigation, water supply, water quality control, recreation, and fish and wildlife. The Missouri River Mainstem Reservoir System Master Water Control Manual (Master Manual) provides guidelines for operating the System. The Master Manual was first published in 1960 and has been revised periodically since then with the most recent revision in 2006. The Corps develops an AOP available in January of each year to forecast the System regulation to serve the authorized purposes under varying hydrologic conditions. Spring updates are also performed to the AOP, as well as other adjustments as needed throughout the year to respond to substantial departures from the expected runoff forecasts.

The following qualitative discussion is provided by the Corps to address reservoir fluctuation and management flexibility issues.

> Since the completion of the power production facilities at the six Corps reservoir projects that comprise the System, virtually all project releases have been made through the respective power plants. When releases are exceptionally high due to flood control evacuation, spillway releases are necessary at Gavins Point and Fort Randall and on rare occasions at Fort Peck and Garrison.

The six Corps projects support 36 hydropower units with a combined plant capacity of 2,501 megawatts (MW). These units provide an average of 10 million megawatt-hours (MWh) of energy per year. Western markets hydroelectric energy and capacity from the System. Firm energy is marketed on a seasonal basis, recognizing the seasonal pattern of releases made for navigation and required for flood control.

During the navigation season, releases from the four uppermost projects are varied in an effort to generate the maximum amount of energy during peak power loads. During the winter, the most critical time period with respect to covering load requirements, releases from Fort Peck and Garrison are scheduled at relatively high rates to compensate for reduced power production at the downstream power plants. The fall drawdown at Fort Randall makes reservoir storage space available for recapture of winter power releases from upstream projects.

In years of low energy generation due to downstream ice problems or low water availability, energy from other sources is obtained in the winter to help serve firm loads. Generally, the navigation season energy generation is adequate to meet firm load requirements; however, during periods of reduced releases for downstream flood control or during extended drought periods, Western must purchase large amounts of energy in the summer to serve firm loads.

In essence, hydropower production is a byproduct of releases from the Corps projects for other authorized project purposes. Each day releases are set at the six projects to provide service for flood control, navigation, hydropower, irrigation, water supply, water quality, recreation and fish and wildlife. There are significant river reaches below Fort Peck and Garrison, so minimum release requirements have been established to serve the water supply and fishery needs below those projects. Oahe and Big Bend are allowed to sustain long periods of zero release because they discharge directly into the next downstream reservoir. Two shorebird species, the interior least tern and the piping plover, nest on sandbars below several of the projects and are protected under the Endangered Species Act. During the tern and plover nesting season, a fixed pattern of hourly releases is specified for Garrison and Fort Randall to reduce risk of inundating the nests of these two species. Releases from Gavins Point are set at a constant rate to provide steady flows in the lower river. Releases from the other five projects may be adjusted within the guidelines provided to meet power needs on a real-time basis.

The Corps's Missouri River Basin Water Management Division conducts studies on a yearly, monthly, weekly and daily basis to determine the release levels that will benefit all of the Congressionally-authorized System project purposes. On a daily basis these release levels are converted into megawatt–hours using a conversion factor based on the power plant characteristics and available head. Daily plus/minus tolerances are set at Fort Peck, Garrison and Fort Randall depending on requirements for other project purposes. Power production orders, which include the daily generation total and tolerances for each project, are forwarded to Western for use in scheduling the following day's generation. Several of the projects also have standing orders that, among other things, set minimum releases. Generation over-runs and under-runs may be taken at any project other than Gavins Point, which is regulated on a water target. Tolerances are not set at Oahe and Big Bend; rather the orders specify that over-runs and under-runs are to be taken in a 3:1 ratio to maintain the desired pool level at Big Bend.

Western has the flexibility to adjust generation to meet its customers needs within the constraints set by the Corps, but attempts to avoid over-running or under-running planned generation for several days in a row. When this does occur, the Corps normally adjusts the planned generation for the following week to make up the difference and, thereby, move the desired volume of water to meet the other authorized purposes.

The addition of wind generation to the hydropower system may result in changes to the pattern of generation from the Corps's projects on a real-time basis over a period of several hours to as much a several days, but is not expected to impact generation at the hydropower facilities over longer time-frames due to the Corps's requirements to move water for other project purposes. The addition of wind generation is also not expected to result in reduced reservoir fluctuations or provide additional flexibility in the management of the reservoir system under the current Master Manual and, in fact, could complicate the management of the System, especially when conditions such as transmission loading relief are taken into consideration.

The water control plan included in the Master Manual is designed to maximize hydropower production during periods of highest demands, namely the summer and winter periods. As previously discussed, higher summer power demands coincide with the higher summer releases needed for downstream navigation flow support annually and for flood storage evacuation in some years. Higher power demands in the winter are met through the annual fall drawdown of Fort Randall reservoir, which makes available space for recapture of winter power releases from upstream reservoirs. In the future, if the addition of wind generation alters (reduces) the monthly or seasonal demand for energy, changes to the water control plan may be necessary to continue to maximize the overall benefit of the Corps's hydropower production to the nation. This will not change the need to release water from the projects for the other Congressionally-authorized project purposes and, therefore, will probably not have a significant affect on long-term reservoir pool levels.

Section 4

Benefits of A Federal-Tribal-Customer Partnership

Legislative Objective – Section 2606 (c)(4)(A) & (B) an identification of—A) the economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership; and B) the manner in which a Federal-tribal-customer partnership could contribute to the energy security of the United States.

Costs/Benefits of Federal-Tribal-Customer Partnership

If an optimal wind integration can be achieved that balances savings during a low hydro generation year with costs incurred during a high hydro generation year, a Federal-Tribal-Customer Partnership (Partnership) could provide benefits to Western UGPR through contracts for delivering wind or other renewable energy to Western's UGPR. Although 25 tribes are already customers of Western's UGPR and receive hydro-generated power through CROD, changing the tribal role to wind or renewable energy providers could add benefits to the tribes, as well as Western, and Western's firm power customers. Federal-tribal partnerships have been used successfully by other federal agencies, such as the Environmental Protection Agency and the US Fish and Wildlife Service. The keystone to a partnership is the interpersonal relationships developed as a result of mutual long-term goals. The long-term nature of a partnership lends itself to enhanced coordination and cooperation between the parties, which generally allows a quick response to issues as they may arise. A Partnership to facilitate delivery of renewable energy to Western using tribal resources present in the UGPR holds promise of benefits to all.

Direct Benefits

Western and its firm power customers may benefit from a contracted-term provision of renewable energy that can mitigate a portion of unknown costs associated with purchase of replacement power. Even with the intermittent nature of wind energy, average annual capacity factors may serve to add stability to Western's generation portfolio, thus reducing the adverse impact of spot market purchases on Western's firm power rate during low and base hydro generation years. A Partnership could also extend into tribal production of other renewable resources such as biomass. Establishing a tribal partnership can provide renewable energy at a known price on a contracted-term basis instead of the current market spot price purchases or short-term energy contracts. A contracted-term tribal partnership for renewable energy reduces some risk associated with uncertainties that are currently looming regarding carbon legislation and fuel price fluctuations. The economic analysis did not include double REC value for renewable energy generated on Federal lands (including tribal lands) that is purchased by Federal agencies. This enhanced REC value might also provide a benefit unique to tribal wind generation.

The tribes could also benefit from a Partnership through long-term revenue streams resulting from power purchase agreements and/or land lease agreements that offer contracted terms for the wind or other renewable energy generated on tribal lands.

Renewable energy production offers advantages over conventional generation for the tribes. Wind energy projects create more jobs per dollar invested and per kilowatt hour (kWh) generated, compared to conventional generation operations. "A New York State Energy Office study recently found that, for identical amounts of electricity produced, wind energy generates 27 percent more jobs than a coal plant and 66 percent more jobs than a natural gas plant." [According to the Wind Energy Issue Brief No. 5, ref-January 1997-National Wind Coordination Committee] Similarly, land required for wind energy production requires a very small percentage of the wind plant footprint. Land around the turbines can often be used for other purposes, such as farming or ranching. Thus, tribal land used for wind power production could benefit from multiple revenue streams.

Depending on the actual contractual arrangements, the tribes may also benefit from jobs during renewable energy project construction, as well as post-construction operation and maintenance jobs.

Indirect Benefits

Western and its firm power customers could also benefit from the indirect or secondary benefits that a Partnership could produce. Secondary benefits from jobs and revenue of the direct benefits listed above would spread throughout economies local to the renewable energy plant development—both tribal and other rural communities that firm power customers serve. Increases in local employment generate demand for other local goods and services. Increased consumer spending would strengthen local communities and create resources to support social and physical infrastructure. At the same time, renewable power plants typically impose a very small demand on local support services such as water, sewer, and transportation services. Thus, the balance of revenue to expenditures required to support development and ongoing operations is very favorable to the local community. Rural communities close to tribal wind projects could benefit from increased economic diversity that tribal renewable energy production would bring.

Wind Energy Security

A Partnership centered around tribal renewable energy projects could also improve national energy security through diversifying technology in Western's energy portfolio, creating geographically distributed energy sources, and reducing impact of fuel price fluctuations. Assuming an optimal economic integration level for tribal wind energy can be achieved for Western's ratepayers, once tribal renewable generation plants are established, costs of energy should be more predictable since renewable generation is not reliant on price of fossil fuel and renewable fuel costs are usually very low. Renewable energy also reduces reliance on foreign energy sources; it requires no imported fuel; and increasingly, manufacturers are producing components for renewable energy production in the U.S. Construction lead times for most renewable energy plants are typically much shorter compared to coal and nuclear plant development requirements allowing for capacity to be added more quickly as it is needed to match load growth.

As discussed earlier in this report, the intermittent nature of wind power reduces the ability to completely substitute wind power for other technology that is dispatchable. Wind does provide an additional fuel source and offers some geographic diversity to the nation's energy portfolio. Further developments in wind turbine technology have advanced the reliability of wind energy production through elimination of many of the historical adverse characteristics of wind energy (e.g., integrated ramping controls). Other dispatchable sources of renewable energy, such as biomass, could also be included in a Partnership and help mitigate the generation variability of wind.

Creating a Federal-Tribal-Customer Partnership around tribal wind energy initially would bring these enhanced security characteristics to Western's supplemental energy resource portfolio—diversity in fuel source which reduces dependence on fossil fuels and geographical distribution of energy resources. This Partnership could also expand to include other renewable energy sources that would further contribute to both energy security and other benefits to Western, its firm power customers and the participating tribes. The long-term nature of a Partnership provides opportunities to address issues as they evolve, promoting solutions that look beyond present day crises to more durable options that better serve Western and its firm power customers.

Section 5

Recommendations for A Tribal Wind Demonstration Project

Legislative Objective: 3) if found feasible, recommendations for a demonstration project to be carried out by the Western Area Power Administration, in partnership with an Indian tribal government or tribal energy resource development organization, and Western Area Power Administration customers to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to the Western Area Power Administration.

The initial Purchase Capacity Bandwidth projected from Western's historical data suggested that up to 333 MW (816 MW wind nameplate) of capacity could be used to meet Western's long term load obligations. However, findings from the market simulations indicate that wind energy with nameplate capacity of 350 MW as compared to a wind energy nameplate capacity of 300 MW shows a net increase in expense to Western's ratepayers over a 30 year period under the assumptions and scenarios that were identified as the scope of the study effort.

The economic analysis conducted for this study revealed the need for additional refinement of the MW bandwidth at which wind energy is most beneficial to Western's ratepayers. Further, since no studies were run between zero and 300 MW to determine an ideal name plate capacity of wind to serve Western load obligations, no blanket economic assumptions can be made below the 300 MW level. Only by running additional studies can Western fully assess the size, benefits, and risks associated with integration of wind to serve Western load obligations on a long term basis below the 300 MW level.

In summary, further refinement of this economic saturation point for wind must be performed prior to determining an ideal nameplate capacity of wind to serve Western load obligations. Therefore, Western recommends conducting additional incremental studies between the 0 to 300 MW range including an assessment of carbon legislation impacts and updating the studies for actual wind development that will have occurred within Western's Balancing Area. Western recommends non-reimbursable funds be made available to complete the refinement of the economic saturation point for wind.

The WHFS workplan was developed under the premise that a Tribal wind energy demonstration project could be integrated into UGPR under existing generating agency operating authorities and operational practices. Additional study needs to be conducted to determine the point at which existing limitations are exceeded due to integrating larger amounts of variable wind energy. Additional study is also necessary to quantitatively assess the costs of increased wind integration on Corps and Reclamation facilities.

These costs may include, but are not limited to:

- Increased unit cycling (stops and starts),
- Increased range and variation in the output of generators,
- Increased wear on electrical and mechanical equipment,
- More frequent replacement of capital equipment and attendant costs,
- Increased plant operation and maintenance (O&M) costs.

Recommendation for a demonstration project – As discussed above, additional study work is needed. However, Western believes a demonstration project recommendation can be made under certain limitations. Western's primary concern with a demonstration project is the economic risk to its ratepayers. Western believes the following limitations are necessary to mitigate this economic risk:

1. A demonstration project if authorized and funded, be of no more than 50 MW nameplate capacity in size; and

2. Any costs of the demonstration project beyond what Western would have normally paid for like energy should not be borne by Western's ratepayers.

Section 6

Conclusions

The recommendations offered in Section 5 are the culmination of 18 months of research and discussions with the Project Team. Efforts were directed at addressing the mandates outlined in the underlying legislation. This report provides results of the Wind Hydro Feasibility Study in Section 2 and summarizes the Report requirements in Sections 3, 4, and 5.

The focus of the WHFS project was to look at cost and feasibility of establishing a Tribal Wind Demonstration Project that uses tribal wind energy to "supplement" Western purchases required when hydro generation is not enough to serve load obligations. This study was performed as described in five Work Elements in Section 2. Study work culminated with market simulations using three hydro scenarios and two wind scenarios to compare costs to Western's customers. The report addressed some additional issues outlined in the legislation including wind energy's impact on reservoir fluctuations.

Purchase Capacity Bandwidth

In Section 2, Work Element 2, the study established a Purchase Capacity Bandwidth of 0 – 333 MW for Western operations to provide a maximum range for supplemental wind energy. This bandwidth was developed using three hydro generation scenarios—LowHydro, BaseHydro, and HighHydro. This bandwidth was developed through analysis of historical data from Western's Data Historian and other relevant operational and contractual information. The range within the bandwidth was driven primarily by the hydro generation variation experienced due to reservoir levels. Periods of drought increase the need to purchase energy, while periods of high water runoff minimize purchases and allow Western to sell excess (surplus) generation.

Western's load allocation is consistent over time, so variation in load does not significantly impact the Purchase Capacity Bandwidth. Some variation from seasonal effects, such as icing in winter, impacts the timing of the purchases (i.e., more purchases on average in winter than in summer). Contractual provisions which allow off-peak return of energy for that used during on-peak hours, reduced the off-peak hourly energy average from 444 MW to the bandwidth maximum of 333 MW.

Wind Energy in Western's Balancing Area and Tribal Wind Energy in UGPR

Maximum value of the Purchase Capacity Bandwidth provided an estimate for the amount of energy that could be purchased by Western over periods of both drought and excess runoff without changing Western from a provider for load obligations to a net seller of energy. This bandwidth, however, is a capacity value, and required some refinement when being applied to tribal wind energy. Two tasks were examined in Section 2, Work Element 3, to further refine the Purchase Capacity Bandwidth for use in evaluating a Tribal Wind Demonstration Project. The first task was to estimate potential tribal wind energy in Western UGPR. The second task was to determine the amount of wind energy that is projected for Western's Balancing Area through 2011.

This estimate of potential tribal wind energy was performed using results from a Tribal Wind Demonstration Project Questionnaire and wind energy simulations from 3TIER. Results from the questionnaire summarized potential tribal wind energy projects within the UGPR that could be candidates for the demonstration project. Wind energy simulations estimated potential for those tribal wind energy projects and established a representative wind profile for each tribal site. The data was not intended to suggest a maximum potential or generic wind profile for the region. It was used as input data for the integration study work and market simulations (see Table 2-6).

Existing and future wind projects expected in Western's Balancing Area through 2011 was determined to be 723 MW not including a Tribal Wind Demonstration Project. This includes 158 MW of existing wind, 265 MW of future non-Western wind, and 300 MW of wind resources to be supplied through a 5-year contract starting in 2011 and running through 2015, to be used to serve Western's load. It is assumed that tribal wind projects could potentially replace the 5-year contract resources once that contract expires and the market simulations used tribal wind profiles to replace the 300 MW 5-year contract wind post 2015.

At 723 MW, this level of wind resources project a 23 percent wind penetration on Western's Balancing Area (peak load is 3090 MW). The size of the Tribal Wind Demonstration Project used in the market simulations was 50 MW, for a total of 773 MW of wind energy raising the wind penetration to 25 percent**.** Results from the estimate of potential tribal wind energy suggests that available tribal wind resources can easily provide 50 MW for the short term, and over the long term, could provide the additional 300 MW to replace the 5-year contracted wind energy as well.

Transmission System Evaluation

Potential constraints created on the transmission system when adding wind to Western's Balancing Area were another consideration. Section 2, Work Element 4 outlines the power load flow studies that were run with future wind projects expected in Western's Balancing Area, both with and without the Tribal Wind Demonstration Project for summer peak conditions. Although there were a significant number of overload and voltage issues associated with the added non-tribal wind projects, the tribal project additions did not require overall grid additions beyond those that would be needed for the expansions without tribal wind.

Similarly, nodal market scenarios were simulated to determine whether flowgates in MAPP were significantly constrained. These results showed there were no significant increases in binding hours on any flowgates for the TribalWind cases that were not already constrained in the BaseWind cases. Hence, there was no significant risk of wind curtailment due to transmission in any of the wind cases, even in the HighHydro scenario.

Economic Comparison of Wind to Serve Western's Load

In Section 2, Work Element 5, the NPV was calculated for costs generated from market simulations for the hydro and wind scenarios identified. Additional costs required for O&M on transmission interconnection line and savings created from RECs were also calculated in 2011 dollars for a net savings of $3.7 million ($123,000 average annual savings) over the outcome of market simulations. This net savings provides a reasonable estimate of considerations that are outside of the market simulations, but it was dependent on assumptions around the length of the interconnection required for a tribal wind project and the actual value of the REC market. This value did not vary with the simulation results, but should be subtracted from net results related to the TribalWind cases.

The NPV of the market simulations was also calculated for comparison purposes. (All dollar values used for cost comparisons are in 2011 dolalrs.) A ReferenceWind case, using only the existing 158 MW of wind in Western's Balancing Area currently, was simulated to provide current costs of Western operations in *PROMOD dollars*. These values were $6.1 billion for the 30-year total during the LowHydro case ($203 million average annual); $4.6 billion for the 30-year total during the BaseHydro case ($154 million average annual); and $3.5 billion for the 30-year total during the HighHydro case ($116 million average annual, see Table 2-15). In other words, if hydro generation averages below the lower quartile for 30 years, it will cost Western's ratepayers $49 million annually ($203 million - $154 million or $1.5 billion over 30 years); if hydro generation is above the upper quartile on average for 30 years, it will save Western's ratepayers $38 million annually ($116 million - $154 million or $1.1 billion over 30 years see Table 2-15). All cases assumed a carbon penalty starting in 2012.

Using the ReferenceWind case as a baseline to compare costs for both the BaseWind and TribalWind cases shows that the BaseWind and TribalWind cases save Western's customers from $29 million over the 30 years (about $1 million average annually--TribalWind – ReferenceWind) in BaseHydro scenario to $112 million over 30 years (about $3.7 million average annually—ReferenceWind – Tribal Wind) in LowHydro scenario (see Table 2-16). Both BaseWind and TribalWind scenarios cost Western's ratepayer more during HighHydro years (BaseWind costs $21 million more than the ReferenceWind case and the TribalWind costs $45 million more than the ReferenceWind case over 30 years--$700,000 and $1.5 million average annual respectively).

Finally, cost comparison between the two wind scenarios (TribalWind and BaseWind) shows the 50 MW of additional tribal wind continues to save Western's customers during the LowHydro scenario ($1.2 million for 30 years or $39,000 average annual cost savings, see Table 2-17). For the BaseHydro scenario, however, addition of the 50 MW of tribal wind to the 300 MW of wind also serving Western's load, does not continue to save Western's ratepayers money (even though it is still a net savings compared to the ReferenceWind case), but costs $12 million more than the BaseWind case ($400,000 average annually). The HighHydro scenario shows that costs for the TribalWind cases are $24 million more than the BaseWind case for the 30-year total ($822,000 average annually). Because the probability of either the low or high hydro generation case is extremely low, these cases serve as analytic markers that indicate the cost/savings impact is non-linear across the threshold at which Western becomes a net seller.

These comparisons suggest that cost savings achieved by using wind to serve Western's load begin to diminish for the BaseHydro scenario above 300 MW of wind, when using the assumptions set forth in these simulations. A maximum economic integration for wind energy being used to serve Western's load may exist at 300 MW or less. Therefore, costs/savings of adding 50 MW for a Tribal Wind Demonstration Project will depend on how much wind is being used to serve Western's load prior to adding the 50 MW. If the 50 MW brings the total wind being used to serve Western's load above 300 MW, Western's customers may experience diminishing returns from the additional wind. Further work may be needed that focuses on determining the conditions that influence the economic saturation of wind integrations on Western's Balancing Area.

Case Run without Carbon Penalty

Members of the Project Team also requested a case that did not include carbon penalties that are expected to be enacted in the near term. This case was compared with the BaseHydro BaseWind case (all hydro and wind cases discussed previously included carbon penalty assumptions) and showed cost savings of $1.2 billion over the 30 years or $40 million annually for Western's ratepayers. This savings is due to Western's penalty-free hydro generation resource and may help to offset impacts a carbon penalized market will have on Western's customers.

MISO/SPP Analysis

Concurrent with WHFS, Western is engaged in evaluating the possibility of joining one of the nearby Independent System Operators—MidWest ISO or Southwest Power Pool. Although results of that study have not yet been released, generally the increased load in a larger balancing area could reduce the impact of the wind variability on operations, thus requiring less incremental operating reserves. (The results from the MISO/SPP analysis will be published in a separate report. None of the quantitative results were used in this study.)

Combined Wind and Hydro Impact on Reservoir Fluctuation

The Corps provided a qualitative opinion that addition of wind generation to the hydropower system may result in changes to the pattern of generation from Corps's projects on a real-time basis over a period of several hours to as much a several days, but is not expected to impact generation at the hydropower facilities over longer time-frames due to the Corps's requirements to move water for other project purposes. Addition of wind generation is also not expected to result in reduced reservoir fluctuations or provide additional flexibility in the management of the reservoir system under the current Master Manual and, in fact, could complicate management of the system, especially when conditions such as transmission loading relief are taken into consideration.

Federal-Tribal-Customer Partnership

If an optimal wind integration level can be achieved with tribal wind, a Federal-Tribal-Customer Partnership (Partnership) could provide benefits to Western UGPR customers through contracts for delivering wind or other renewable energy to Western's UGPR. During periods of low and base level generation, Western and its firm power customers could benefit from long-term provision of renewable energy that can mitigate a portion of the unknown costs associated with purchase of replacement power. A Partnership could also extend into tribal production of other renewable resources such as biomass. Establishing a tribal partnership can provide renewable energy at a known price for a negotiated term instead of the current market spot price purchases.

A long-term tribal partnership for renewable energy could reduce some of the risk associated with uncertainties that are currently looming regarding carbon legislation and fuel price fluctuations. Secondary benefits from jobs and revenue would spread throughout economies local to the renewable energy plant development—both tribal and other rural communities that firm power customers serve. Increases in local employment would generate demand for other local goods and services.

Creating a Federal-Tribal-Customer Partnership around tribal wind energy could also bring enhanced security characteristics to Western's energy resource portfolio—diversity in fuel source which reduces dependence on fossil fuels and geographical distribution of energy resources. The long-term nature of a Partnership provides opportunities to address issues as they evolve, promoting solutions that look beyond present day crises to more durable options that better serve Western and its firm power customers.

Recommendations for a Tribal Wind Demonstration Project

The initial Purchase Capacity Bandwidth projected from Western's historical data suggested that up to 333 MW (816 MW wind nameplate) of capacity could be used to meet Western's long term load obligations. However, findings from the market simulations indicate that wind energy with nameplate capacity of 350 MW as compared to a wind energy nameplate capacity of 300 MW shows a net increase in expense to Western's ratepayers over a 30 year period under the assumptions and scenarios that were identified as the scope of the study effort.

The economic analysis conducted for this study revealed the need for additional refinement of the MW bandwidth at which wind energy is most beneficial to Western's ratepayers. Further, since no studies were run between zero and 300 MW to determine an ideal name plate capacity of wind to serve Western load obligations, no blanket economic assumptions can be made below the 300 MW level. For example, the conclusion of the anticipated 5-year 300 MW contract through 2015 would present an opportunity to add up to 350 MW of Tribal wind, with an undetermined economic saturation point between 300 MW and 350 MW based on the assumptions in this study. Only by running additional studies can Western fully assess the size, benefits, and risks associated with integration of wind to serve Western load obligations on a long term basis below the 300 MW level.

In summary, further refinement of this economic saturation point for wind must be performed prior to determining an ideal nameplate capacity of wind to serve Western load obligations. Therefore, Western recommends conducting additional incremental studies between the 0 to

300 MW range including an assessment of carbon legislation impacts and updating the studies for actual wind development that will have occurred within Western's Balancing Area. Western recommends non-reimbursable funds be made available to complete the refinement of the economic saturation point for wind.

The WHFS workplan was developed under the premise that a Tribal wind energy demonstration project could be integrated into UGPR under existing generating agency operating authorities and operational practices. Additional study needs to be conducted to determine the point at which existing limitations are exceeded due to integrating larger amounts of variable wind energy. Additional study is also necessary to quantitatively assess the costs of increased wind integration on Corps and Reclamation facilities including the 723 MW of wind already anticipated by 2011 irregardless of a Tribal Wind Demonstration Project.

These costs may include, but are not limited to:

- Increased unit cycling (stops and starts),
- Increased range and variation in the output of generators,
- Increased wear on electrical and mechanical equipment,
- More frequent replacement of capital equipment and attendant costs,
- Increased plant operation and maintenance (O&M) costs.

As Western considered the recommendation for a demonstration project, several key influences were assumed:

- The specified objectives contained in the Section 2606 legislation.
- Western's legislated role as a supplemental energy provider with no load growth responsibility.
- The impact to hydro-generation resource regulation capacity resulting from development of wind energy generation facilities within Western's control area serving non-Western load.
- The physical impacts to hydro-generation plant facilities resulting from fast regulation imposed by all wind generation facilities in the balancing area,
- The conclusions reached in this study do not limit wind development in the region constructed to serve load outside of Western's balancing area.

As discussed above, additional study work is needed. However, Western believes a demonstration project recommendation can be made under certain limitations. Western's primary concern with a demonstration project is the economic risk to its ratepayers indicated by costs calculated in extremely unlikely High Hydro case. Western believes the following limitations are necessary to mitigate this economic risk:

1. A demonstration project be of no more than 50 MW nameplate capacity in

size if authorized and funded prior to 2015, and less than 350 MW in size if authorized and funded after 2015; and

2. Any costs of the demonstration project beyond what Western would have normally paid for like energy should not be borne by Western's ratepayers.

Appendix A

WHFS Project Team Roster

WIND HYDRO FEASIBILITY STUDY
PROJECT TEAM ROSTER

Mr. Michael A. Radecki
Western Area Power Administration
Upper Great Plains Region
2900 4th Ave. North
Billings, MT 59107-5900
Phone (406) 247-7442
FAX (406) 247-7408
Radecki@wapa.gov

Mr. James L. Haigh
Western Area Power Administration
Watertown Operations Office
P.O. Box 790
Watertown SD 57201-0790
Phone (605) 882-7520
FAX (605) 882-7409
Haigh@wapa.gov

Ms. Jody Farhat, P.E.
Power Production Team Leader
Missouri River Basin Water
Management Division
Northwestern Division, Corps of
Engineers
12565 West Center Road
Omaha, NE 68144
Phone (402) 697-2686
FAX (402) 697-2677
jody.s.farhat@usace.army.mil

Mr. Trevor McDonald, E.E
U.S. Army Corps of Engineers
Big Bend Project Office
33573 N. Shore Rd
Chamberlain, SD 57325
Phone (605) 245-2331, ext 3002
Fax (605) 245-2556
Trevor.R.McDonald@usace.army.mil

Mr. Karl A. Wunderlich, Ph.D.
U.S. Bureau of Reclamation
Power Resources Office
Denver Federal Center, Bldg. 67
PO Box 25007, D-5400
Denver, CO 80225-0007
Phone (303) 445-3636
kwunderlich@do.usbr.gov

Ms. Paulette Schaeffer
Power Operations
U.S. Bureau of Reclamation
Great Plains Regional Office
P.O. Box 36900
Billings, MT 59107-6900
Phone (406) 247-7642
FAX (406) 247-7898
pschaeffer@gp.usbr.gov

Mr. Darin Larson
Regional Hydrologist
BIA Office of Natural Resources
115 4th Ave. SE
Aberdeen, SD 57401
Phone (605) 226-7621
FAX (605) 226-7358
NO E-MAIL AT THIS TIME – MUST
MAIL/FAX ALL CORRESPONDENCE

Mr. Scott Doig
BIA Environmental Services
Mid-West Regional Office
Henry Whipple Federal Bldg.
1 Federal Drive, Room 550
Fort Snelling, MN 55111
Phone (612) 725-4514
FAX (612) 713-4401
NO E-MAIL AT THIS TIME – MUST
MAIL/FAX ALL CORRESPONDENCE

Mr. Brian Parsons
Project Manager, Wind Applications
National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, CO 80401-3393
Phone (303) 384-6958
FAX (303) 384-6901
brian_parsons@nrel.gov

Mr. Mike Costanti
Blackfeet Nation Representative
Principal Engineer
Matney Frantz Engineering
105 W. Main St., Suite G
Bozeman, MT 59715
Phone (406) 556-9827
mcostanti@matneyfrantz.com

WIND HYDRO FEASIBILITY STUDY
PROJECT TEAM ROSTER

Mr. Thomas L. Weaver
Fort Peck Tribes Representative
2013 S. Holland St
Lakewood, CO 80227
Phone (303) 378-6485
FAX (303) 988-3695
Tlweaver2013@cs.com

Mr. Warren Mackey
Santee Sioux Nation
Santee Sioux Tribal Housing
207 His Red Nation Street
Niobrara, NE 68760
Phone (402) 857-2656
FAX (402) 857-2608
ssthaadmn@gpcom.net

Mr. Patrick Spears
President
Intertribal Council on Utility Policy
P.O. Box 224
Fort Pierre, SD 57532
Phone (605) 223-2416
Pnspears2@aol.com

Mr. Vic Simmons
General Manager
Rushmore Electric Power Cooperative, Inc.
P.O. Box 2414
Rapid City, SD 57709-2414
Phone (605) 342-4759
Fax (605) 348-2026
vsimmons@rushelec.com

Appendix B

WHFS Project Work Plan

Wind/Hydro Feasibility Study (WHFS)
Western Area Power Administration
Project Work Plan
November 5, 2007

Table of Contents

Introduction

The Energy Policy Act of 2005, Sec. 2606, required a study be performed by the Department of Energy (DOE) involving wind-hydro integration. Western Area Power Administration (Western) was tasked by DOE to perform a study of cost and feasibility to develop a demonstration project that uses wind energy generated on Indian Tribal lands and Federal hydroelectric power generated on the Missouri River to supply firming power to Western to meet its contractual obligations.

EPAct 2005, Sec 2606 Requirements

The Energy Policy Act of 2005 (EPAct 2005), Section 2606 required that the Secretary of Energy perform a study of the cost and feasibility of developing a demonstration project that uses wind generated electrical energy by Indian tribes and hydropower on the Missouri River by the US Army Corps of Engineers to supply firming power to Western.

EPAct 2005 stipulated that the study shall:

a. Determine the economic and engineering feasibility of blending wind and hydropower generated from the Missouri River dams operated by the Army Corps of Engineers including an assessment of the costs and benefits of blending wind energy and hydropower compared to the current sources used for firming power to Western,
b. Review historical and projected requirements for, patterns of availability and use of, and reasons for historical patterns concerning the availability of firming power,
c. Assess the wind energy resource potential on tribal land and projected cost savings through a blend of wind and hydropower over a 30-year period
d. Determine seasonal capacity needs and associated transmission upgrades for integration of tribal wind generation and identify costs associated with these activities.
e. Include an independent tribal engineer and a Western customer service representative as study team members, and
f. Incorporate, to the extent appropriate, the results of the Dakotas Wind Transmission study prepared by Western

EPAct 2005 further requires that the study report shall describe the study results including:

a. An analysis and comparison of the potential energy cost or benefits to the customers of Western through the use of combined wind and hydropower.
b. An economic and engineering evaluation of whether a combined wind and hydropower system can reduce reservoir fluctuation, enhance efficient and reliable energy production, and provide Missouri River management flexibility.
c. If found feasible, recommendations for a demonstration project to be carried out by Western, in partnership with an Indian Tribal government or tribal energy resource development organization, and Western customers to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to Western
d. An identification of :

    1. The economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership.
    2. The manner in which Federal-tribal-customer partnership could contribute to the energy security of the United States.

Pursuant to the DOE tasking, a Project Team was established that includes participants from affected Federal Agencies and Western customers including Western Tribal customers. On March 12, 2007 Western initiated the development of the project team via formal request to the Tribal Chairperson of each Tribal organization within Western's Upper Great Plains Region (UPGR). Project team members designated to represent non-Tribal customers were identified through coordination with the Mid-West Electric Consumers Association.

The Project Team members currently include:

- Blackfeet Nation – Bozeman, MT
- Ft. Peck Tribal Energy Department – Lakewood,
- Santee Sioux Nation – Niobrara, NE
- Intertribal Council on Utility Policy (ICOUP) – Ft. Pierre, SD
- Midwest Electric Consumers Association - Rushmore Electric Cooperative – Rapid City, SD; Nebraska Public Power District-Columbus, NE; Heartland Rural Electric Cooperative-Girard, KS
- National Renewable Energy Laboratory Denver, CO
- U.S. Army Corps of Engineers – Omaha, NE
- U.S. Bureau of Reclamation
- U.S. Bureau of Indian Affairs
- Western Area Power Administration Upper Great Plains Region

Stanley Consultants, Inc. was selected by Western as the prime contractor to perform the studies to address the DOE tasking under its existing contract. Stanley Consultants will utilize the services of NewEnergy Associates (NEA) as a major subcontractor to perform the work scope.

It is the purpose of this Project Work Plan to outline the approaches and schedule to be utilized to perform the work scope.

Background

The purpose of the WHFS is to focus on the potential of wind generation to displace energy purchased by Western to supplement available hydro generation to serve contracted requirements and the impact of that generation on UGPR transmission network. The tribal wind energy would be supplied by long term contracts between Western and tribal-owned wind generation for the entire projects' output. Potential impacts to the UPGR grid and Western customers would be studied. Impacts would include those caused by the potential physical interconnection, wind facility operations, and economic costs and benefits to Western customers.

There has been significant study performed over the past few years defining and analyzing the electric generation wind resource. These studies have identified operational and system interactions between wind installations and the general transmission network. Their analysis and results will be used to support and potentially provide specific data to the WHFS analysis.

The significant work to date includes:

- Studies that concerned the general UPGR include:
    - *Final Report – 2006 Minnesota Wind Integration Study: Volumes I and II,* November 30, 2006, Prepared for The Minnesota Public Utilities Commission

      This study was performed in response to the May 2005 Minnesota Legislature's requirement to evaluate the impact on electric system reliability and costs associated with increasing wind penetration in electric utilities in Minnesota to twenty (20) percent. Covering the general areas of Minnesota and the eastern parts of North and South Dakota, this study provides background on different levels of wind penetration effects on system generating operations, production costs and reserve margins. It also discusses impacts on the transmission grid in this area. Although not specifically addressing the Western UPGR, it does provide a review of the issues associated with significant wind penetrations on the displacement of coal and gas fired generation which have similar costs to those that Western may have historically purchased along with highlighting operational requirements.

- *Draft Report: WAPA Missouri River Wind Integration Study,* August 4, 2006, Prepared for The National Renewable Energy Laboratory

  This study focused on the impacts of a wind generation scenario on Western hydroelectric operations for the 2003 calendar year. The study provides data and analysis of potential overall Western responses to different wind penetration level in the Dakotas. The results will provide supporting data to operational characteristics.

- *Dakota Wind Transmission Study – Task 1: Non-Firm Transmission Potential to Deliver Wind Generation; Task 2 Final Report: Transmission Technologies to Increase Power Transfer; and Tasks 3 and 4 Draft Report: System Impact Study and Transfer Capability Study Prepared for the Western Area Power Administration* In 2005

  This study reviewed the impacts of the insertion of 500MW of wind turbines into the electric transmission grid at various locations throughout North and South Dakota. The studies provided a detailed analysis of transmission grid impacts including power flows, short circuit, and transient stability considerations. The report provides a significant data resource for quantifying transmission response to wind energy operations on the transmission grid.

- Other studies of interest would include the *Northwest Wind Integration Action Plan,* pre-publication dated March 2007 provides a discussion of an approach that one geographic region is taking to the integration of wind energy sources into the overall regional electric system. The report highlights potential issues that may also need to be addressed by a demonstration project in Western UPGR.

Study Approach

The WHFS Project Team has met on two occasions to address the completion of this project. On May 2, 2007, the Team met via conference call to discuss the overall scope of the WHFS study as outlined in EPAct 2005 Section 2606 and the role of the Team members. The identification of potential tribal projects and the development of the Work Plan was also reviewed.

The Project Team then met on June 1, 2007, in Rapid City, SD, to develop an overall project approach as well as to identify specific needs or issues of the participating project team members. The Project Team identified several key components that translate into the overall WHFS approach:

- The WHFS will concentrate on wind energy delivered to UGPR customers

- Indian Nation wind energy will be used to displace purchases that Western would historically have made to replace energy requirements that were not served by hydro-generation
- The WHFS will address the operating recommendations as previously identified in previous studies listed above
- The potential impacts will be based on candidate demonstration projects identified on tribal lands that would meet the aggregated historical Western needs as selected from candidates' responses to a questionnaire to be developed by the project
- There will be Project Team technical reviews at various identified stages of the project
- The transmission analysis will incorporate Western's already identified network additions

The WHFS project will address the EPAct 2005 requirements through a series of Work Elements described below and referenced in Chart 1. Each Work Element will include written summaries for input into the concluding report.

- **Work Element 1 – WHFS Work Plan**

  This WHFS Work Plan was developed to communicate the approach to the WHFS Project Team and the general public. The DRAFT Work Plan was submitted for WHFS Project Team review and comment and updated as agreed and distributed through Western for public comment. One public meeting was held in Bismarck, ND on September 27, 2007. This Work Plan was prepared considering all comments received.

- **Work Element 2 - Analysis of Historical Western Purchase Requirements**

  Data will be requested from Western that describes the historical requirements and cost for additional energy required to meet obligations. From this historical cost and load data, an effective minimum and maximum potential for capacity and energy replacement will be developed.

  The data required will include but is not limited to:

  - Contractual requirements including, but not limited to:
    - Customer list with maximum capacity obligations
    - Historical hourly load obligations by control area or smaller geographical area if constrained (ie, North of NDEX, etc).
  - Actual energy purchased and generated
  - Losses and actual system deliveries
  - Historical water availability and forecasts
  - Excess sales including energy and revenues
  - Historical, current, and projected reserve requirements
  - Transmission analytical models

- Organizational and institutional operating requirements
- Current operational procedures
- Forecasted water availability for generation
- Historical and Projected Purchase Power Costs
- Historical Hourly DC Tie flows
- Historical Hourly Hydro Generation by Unit and/or Plant
- Duplicate Hourly Wind Project Input to UGPR Transmission System by Project and Geographical Locations

The historical data will form the basis for a multi-year operational model that reflects historical Western operations. These historical operations will be used to estimate an effective amount of capacity and energy available for tribal wind energy projects.

Work Element 3 – Wind Project Identification

Work Element 3 provides the selection of the representative sample project identification and the requirements for wind projects to meet.

- **Questionnaire Development**

  A questionnaire (Appendix A) has been developed to provide information on proposed projects for use in selection to demonstrate potential costs and benefits associated with the use of wind power to displace purchased energy. The draft questionnaire requests data required to support Work Element 3 along with characteristics that may be identified in Work Element 2 as required of tribal wind energy. The questionnaire will be provided as requested to potential wind projects for their consideration and completion.

- **Wind Project Review and Identification**

  Completed questionnaires submitted by candidate wind projects will be reviewed and projects selected for further review. Potential wind projects will be selected based on the completeness and comprehensiveness of data provided to support the Work Element 5 scope and the stage of actual project development. The selection of the sample projects to demonstrate the operation and interactions with the UGPR will be based on the results of Work Element 2 requirements and potential project data that support the analysis.

  The projects submitted by the tribes combined with the historical and projected Western energy requirements will form the basis of the maximum utilizable wind energy to meet Western firm power obligations.

- **Work Element 4 – Transmission System Evaluation**

  The tribal wind energy projects selected in Work Element 3 will be used to evaluate UGPR potential transmission system impacts. Note that any sample project used for this analysis will be subject to the Western OATT process and therefore will require formal Feasibility, System Impact and Facility Studies be performed at a later date for wind project Interconnection and Network Service as with any other generation project.

  The base transmission system will reflect the transmission improvements in the grid as identified by Western for the study period. Existing Western transmission studies will reflect the currently projected transmission operating characteristics.

  Estimates of required sample wind project physical interconnection requirements will be determined based on similar wind projects and transmission reliability standards. Work Element 4 will identify potential UGPR system impacts initially based on previous wind-transmission system network studies listed above. Augmentation of available transmission impacts along with the need for additional specific load flow, short circuit, and stability analysis will be identified and reviewed with the WHFS Project Team prior to any execution.

- **Work Element 5 – Assessment of UGPR Impacts**

  Work Element 5 will concentrate on the impacts on Western total net production costs over the study period. The PROMOD IV software will be used to model system operations and loads based on agreed water forecasts and wind project energy projections using hour-by-hour simulation. Water forecasts will be agreed with Western planners for the entire simulation period. Similarly, wind energy forecasts will be either supplied by the potential project or agreed with the selected project(s) based on mesoscale modeling.

  The study performed will have two major components; long term economics and operational feasibility. The long term economics of replacing Western's current purchased power are driven mainly by the market price of energy given that Western buys a majority of its supplemental energy from the spot market and has no long term contracts in place for that energy. For this portion of the study, a 30 year zonal analysis of the MAPP energy prices will be performed. Under that approach, transmission constraints are reflected between zones, but detailed transmission operations are not modeled.

  The operational feasibility portion of the study will be performed in more detail, but over a shorter time frame. Utilizing PROMOD IV security constrained economic dispatch (or nodal) modeling capabilities, the effects of detailed transmission constraints resulting from the inclusion of tribal wind energy in the Western portfolio will be captured.

Three major cases will be evaluated using the following approach:

- **Base Case Zonal Study –** This case will represent a 30-year outlook designed to measure Western's power supply costs, and to reflect the long-term economic impacts associated with integrating energy from wind projects being developed by the Indian Nations. A base case will be prepared to specify Western load requirements, supply, hydroelectric energy and fuel price forecasts in the upper Midwest/MAPP region, in addition to other key fundamental study assumptions. This will include the sample wind projects in the UGPR system over the study period, as determined through the Work Element 3 process. Simulations will be completed both with and without the sample wind projects included, with the latter case being used to establish a baseline set of projections to be used as comparison in evaluating the impacts of integrating energy from those projects.

  Specific steps will include:

  - Updating the existing databases to reflect current load/supply/hydroelectric energy/fuel price forecasts in upper Midwest/MAPP region
  - Meet with WHFS Project Team to:
    - Finalize the case list
    - Present basic assumptions including proposed 30-year expansion plan
    - Specify basic wind project data from the data collection, project screening, mesoscale modeling results
  - Set any revisions to basic assumptions using WHFS Project Team's feedback
  - Complete Base Case zonal modeling for 30-year study period - with and without new wind capacity
  - Present Base Case zonal results to WHFS Project Team

  - **Wind/Hydro Scenarios - Zonal Study –** This step will complete additional PROMOD IV zonal modeling. The specific modeling will be designed to measure the impact of wind integration on the UGPR system, under a variety of hydroelectric conditions, and based on differing levels of wind penetration. As such, additional simulations will be completed where the amount of expected hydroelectric energy is varied to reflect wet-year and dry-year conditions. The specific hydro conditions reflected in the scenarios will be derived based upon Western's historical data provided under Work Element 2, and after seeking feedback from the WHFS Project Team. Varying wind energy penetration will also be reflected in these scenarios. The goal of these scenarios is to provide robust measurement of the economic impacts on Western's system arising from integration of greater amounts of wind generation, under varying hydro conditions. Capacity value of wind will be incorporated as appropriate, based on current research and system practices.

Execution steps will include:

- Specify Increased Wind Penetration Scenario, based on Tier 2 and Tier 3 ranked wind projects
- Specify two (2) discrete wind/hydro sensitivity cases based on mesoscale modeling data
- Complete PROMOD IV scenario modeling of both Base and Increased Wind Penetration scenarios, for each of the wind/hydro cases over the 30-year study period.
- Present Scenario case results to WHFS Project Team

Base and Scenario Case Detailed Operational Nodal Study – PROMOD IV simulations of the base case and scenario cases will be performed using detailed transmission modeling and PROMOD IV's security constrained economic dispatch capabilities. The primary goal will be to evaluate how additional injections of wind energy into the UGPR affect overall system operations and transmission constraints. A single year 2011 is proposed for this study and to complete detailed transmission modeling of previous cases for that year. 2011 was selected as it is the year in which the wind projects are likely to be online and is available as a transmission model from industry data. It will be important to model the transmission and generation systems as they are expected to exist when the projects are operational. Hourly analysis will be used.

Results from these cases will be used to assess whether wind integration into Western's system has any favorable or adverse impacts upon system operations and upon transmission constraints on that system.

Included in the analysis for 2011 will be:

- Completion of the nodal MAPP study based on base case conditions with and without new wind projects
- Complete nodal MAPP study based on 2011 base case conditions, plus two wind/hydro sensitivity cases
- Complete nodal MAPP study based on High Wind Penetration conditions
- Complete nodal MAPP study based on the 2011 high wind penetration conditions, plus two wind/hydro sensitivity cases
- Present Nodal case results to WHFS Project Team

The above thirty-year production cost simulations combined with amortized transmission and capacity costs will form the basis of the 30 year present worth costs. Differences between base simulation and simulation incorporating wind projects will form the components of the cost-benefit computations.

- **Work Element 6 – Draft and Final Report Preparation**

  A draft report will be prepared for review with the WHFS Project Team that incorporates the summaries developed in each Work Element. A final report will be prepared utilizing agreed WHFS Project Team comments.

  Specific topics to be addressed in the WHFS report include:

  - Comparison of the potential energy cost or benefits to the customers of Western through the use of combined wind and hydropower.
  - Description of the economics and engineering/operational characteristics of the combined wind and hydropower system on Western's UPGR including potential reductions of reservoir fluctuation, impacts on the efficiency and reliable energy production for Western customers, and identified Missouri River management flexibility.
  - Recommendations for and general criteria for a project to be carried out by Western, in partnership with an Indian Tribal government or tribal energy resource development organization to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to Western
  - Discussion of identified economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership
  - Description of the manner in which Federal-tribal-customer partnership could contribute to the energy security of the United States.

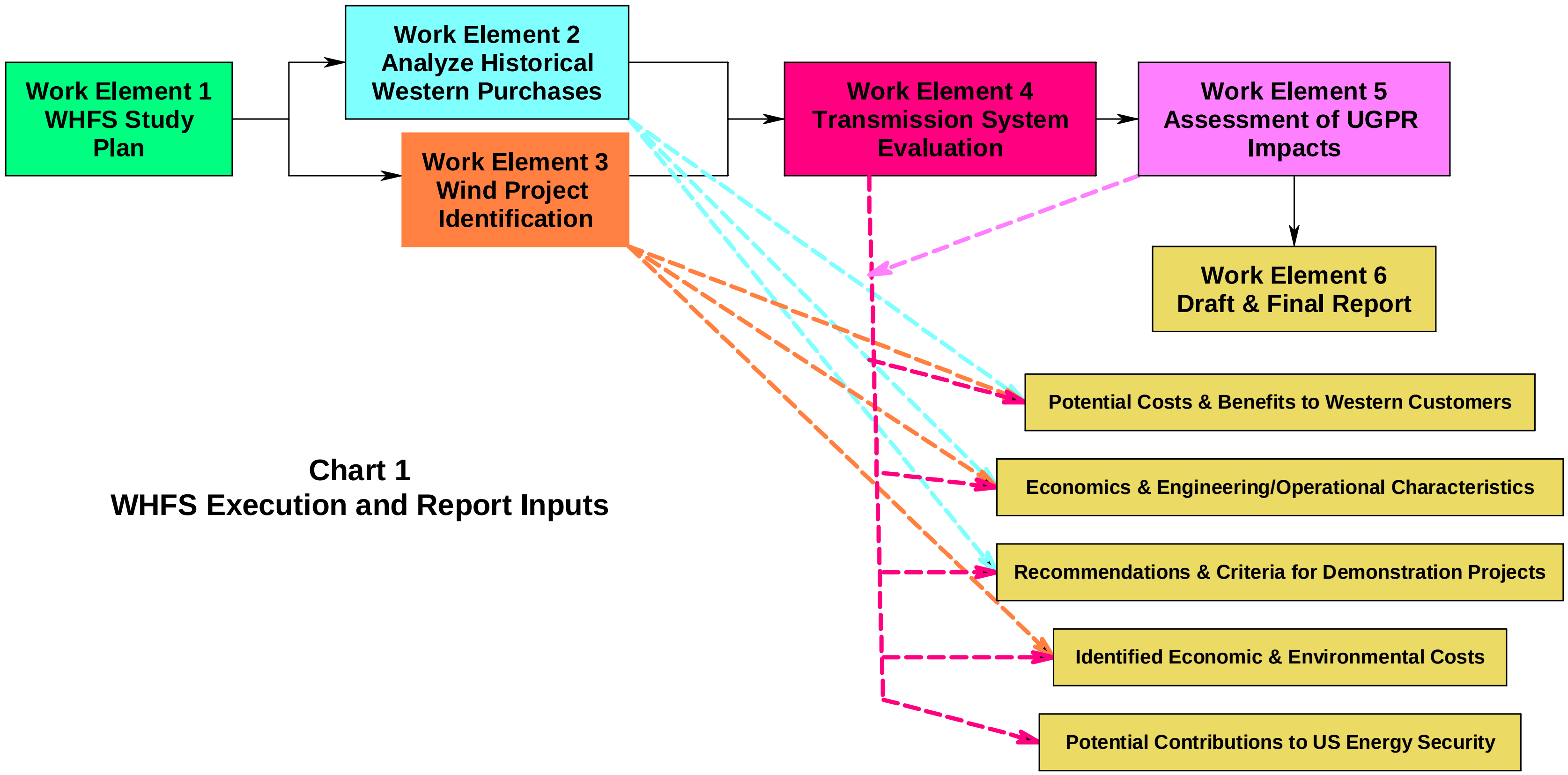


Chart 1
WHFS Execution and Report Inputs

APPENDIX A

RESPONSE TO COMMENTS

The following comments were discussed:

Action Codes: A-Agree Change will be made D-Discussion point only; no change to Work Plan O-Other action will be taken			
Comment No.	**Reference**	**Comment**	**Review Action**
1	Introduction	The Project Team has expanded to include MidWest Electricity Consumers Association; Will team be voting?-*All members will be kept informed and have an opportunity to review materials at appropriate intervals*	A-*Modify Work Plan to reflect new members*
2	Background	Replace term "displacement energy" with something more descriptive-supplemental rejected since it already has a specific meaning within the system.	A-*Replace "displacement energy" with "tribal wind energy"*
3	Study Approach	Question referring to…address the operating recommendations-important to this project— *will be discussed further in Work Element 5, i.e., sub hourly*	A – *Although not specifically addressed in the Work Plan, the need for sub-hourly analysis will be addressed based on the Work Elements 2, 4, and 5 and capacity level based on industry research.*
4	Work Element 1	One public meeting to be held in Bismarck, ND, with an information session in the morning immediately followed by public comment forum.	A-*A public meeting was held in Bismarck, ND, on September 27, 2007.*
5	Work Element 2	Question regarding the phrase…Transmission analytical models	D-*Refers to the models used for transmission planning purposes by Western*
6		Question referring to…Historical hourly DC tie flows	D – *Refers to Ft. Peck generation—the portion of energy generated on the Western portion of the grid that is transferred to the Eastern grid—the information on this transfer of power will be used to schedule power in the future-this will provide more background data than direct impact*
7		Question referring to…Duplicate hourly wind project input…question duplicate—*referring to wind in system behind the meter*	A-*Replace "duplicate" with "existing*"
8		What is "take away" from historical analysis?	D - *To establish Western's energy purchase needs to provide baseline data to integrate wind into the system under the legislation*
9		Discussion regarding the analysis of sufficient levels of total wind generation to yield meaningful results	A – *The level of wind usage is a function of actual historical purchase patterns which will be established during Work Element 2.*
10	Work Element 3	Questionnaire Development	D – *A draft questionnaire from Tom Wind and Mike Costanti was submitted to Mike Radecki*
11		Wind Project Review and Identification	A- *Information from the questionnaires on the proposed wind projects will determine parameters of demonstration project-the more developed the research in the responses, the higher priority for the project*
12		Question regarding release of proprietary information regarding Tribal projects	D - *Tribes certainly have the right to with hold proprietary information regarding the development of projects. The impact of incomplete or missing information is unclear at this time; missing information could result in the inability to provide a complete assessment of the cost/benefit and viability of wind integration.*
13		Comment regarding amount of wind to be evaluated under this study and any demonstration project should be of a meaningful value; integrating a few MW wouldn't impact the system-rather, this study should adopt an integration percentage of 10-15% with an ultimate goal of 15-25%	D - *Participants generally agreed that any recommendation for a demonstration project should be of sufficient size to provide meaningful information resulting from that integration. Following the requirements of Sec. 2606, the amount of wind identified will be related to the amount that could be integrated for Western's use in meeting its firm power obligations. Establishing an integration percentage at this point would be premature. A demonstration project recommendation will be sent to Congress for action; there may be a low, medium and high option utilizing more than one project. Although the Dakotas Wind Study indicated that the transmission system could convey up to 500MW on a non-firm basis 95% of time which would represent approximately 25% penetration, this study will address the amount of wind that Western can utilize based upon historical purchase patterns in Work Element 2.*
14		Question regarding production tax credits	D - *The questionnaire will include a section to describe partnership arrangements that could be part*

			of a demonstration project such as allowing PTCs to be used.
15	Work Element 4	Comment regarding transmission system study should include a "full integration of tribal wind power assuming" various hydrologic years	D - *Work Element 2 utilizes historic lows and highs to define the minimum and maximum hydro generation. Work Element 3 identifies total potential tribal generation. Work Element 4 synthesizes this information and refines the potential impact on the transmission system.*
16		Question regarding Large Generator Interconnect Agreement process	D - *This will be responsibility of demonstration project team; basic feasibility of interconnect will be part of demonstration project*
17		Comment made that distribution system impact will need to be determined for each project as well as transmission system impacts	D – *Western is responsible for its transmission system. It is unclear at this point in time as to whether or not there are distribution systems involved in specific projects.*
18		Question regarding use of previous wind transmission system network studies	D - *These will be used in addition to a review of current models to evaluate feasibility of project submittals*
19	Work Element 5	Question regarding inter-annual variation of water availability and its affect on the hydro – wind coordination	*D – Projected water variation will be based on available forecasting from the US Corps of Engineers and reflected against the operations as dictated by the Master Manual*
20		Question regarding the impact of wind-energy availability on water use optimization of Missouri River	*D – Water usage is regulated by the Master Manual*
21		Question regarding the effects of short-term hydro generation fluctuations arising from coordination with wind generation	D – *Hydro operations are constrained by existing contracts and Master Manual operating rules*
22		Question on impacts of hydro and river constraints on wind penetration and value	D – *Wind requirements will be computed in Work Element 2. See also responses to Comments 19 - 21*
23		Question regarding Zonal analysis and approach	D – *Approach includes a broad overview (30 years) of projected costs/savings for blended wind/hydro and includes a simplified determination of value costs of offsets and purchases. The nodal study has full representation of the transmission and generation systems.*
24		Discussion regarding sub-hourly modeling	D – *Previous studies have indicated that large penetrations of a size greater than the projected demonstration project are required for sub-hourly effects to be of concern. The need for sub-hourly analysis will be determined based on the actual recommended levels of wind integration. In addition, 15 minute interval wind output data is available for existing projects that will be reviewed for possible trends. Also, it is assumed that adequate wind forecasting should minimize wind project forced outage rates.*
25		Question regarding development of statement of work for mesoscale modeling	D - *Should a SOW for mesoscale modeling be required, the WHFS project team would have the opportunity to provide input*
26	Work Element 6	Question about …Recommendations for and general criteria for a project…singular form	D - *Wording taken directly from the legislation*
27	Other	A comment was made that FreedomWorks, LLC is an organization that exists in the Western United States	D - *The comment regards issues and organizations outside the scope of the WHFS*

This page intentionally left blank

Mid-West Electric Consumers Association

October 19, 2007

Mr. Robert Harris
Regional Manager
Upper Great Plains Region
Western Area Power Administration
2900 4th Avenue, North
Billings, MT 59101-1266

Dear Mr. Harris,

The Mid-West Electric Consumers Association appreciates the opportunity to comment on the Western Area Power Administration's ("Western") Draft Wind/Hydro Feasibility Study (WHFS) Project Work Plan, pursuant to Western's September 19, 2007 Federal Register notice.

The Mid-West Electric Consumers Association was founded in 1958 as the regional coalition of over 300 consumer-owned utilities (rural electric cooperatives, public power districts, and municipal electric utilities) that purchase hydropower generated at federal multi-purpose projects in the Missouri River basin under the Pick-Sloan Missouri Basin Program.

The Wind/Hydro Integration Feasibility Study (WHFS) is mandated by the Energy Policy Act of 2005 (EPAct2005). The instructions for the study, frankly, do not make sense. The legislative language seeks to explore "the economic and engineering feasibility of blending wind energy and hydropower generated from the Missouri River dams . . . including an assessment of the costs and benefits of blending wind energy and hydropower compared to current sources used for firming power to the Western Area Power Administration . . ."

All of the marketable hydropower in the Pick-Sloan Missouri Basin Program has been allocated to preference customers, including Native American Tribes. So, the only hydropower available for this "blending" would be the allocation of a tribe seeking to integrate its wind resource. EPAct2005 does permit the tribes to use their allocation for this purpose. Is that Pick-Sloan allocation sufficient to meet the engineering requirements of the blending of hydropower and wind energy envisioned by the study?

As indicated in the statute and as utilized in the Wind/Hydro Integration Feasibility Study (WHFS) approach, the term "firming" refers to purchases required by Western to meet Western's current long term allocation commitments. The term "blending" is equivalent to integrating wind into the hydro generation along with other purchased generation to provide enough generation to meet these long term allocation commitments. The WHFS plan does not include the incorporation of Tribal wind energy that is firmed with Tribal hydropower allocations, as such the WHFS approach does not impact any specific allocation.

4350 Wadsworth Blvd., Suite 330, Wheat Ridge, CO 80033
Tel: (303) 463-4979 Fax: (303) 463-8876

It is not at all clear how using federal hydropower generation to firm Native American wind development will be able to then be used to firm the hydropower Western markets under the Pick-Sloan Missouri Basin Program. If this means that Western will be selling federal hydropower at cost-based rates and then re-buying a mix of wind and federally generated hydropower at market rates, the economics would clearly discriminate against Western's firm power customers.

The WHFS approach does not "firm Native American Wind energy." This project will only recommend whether or not to run a demonstration project using some level of intermittent, non-firm Tribal Wind energy as part of the existing purchases made by Western to meet current allocation commitments.

The modeling that the study proposes must be conducted for a variety of hydrology conditions in the basin – both good water and bad. The study must address that range of generation scenarios in determining the amount of renewables that Western could purchase.

There are high and low water scenarios built into the production model analysis specifically in Work Element #5 (Wind/Hydro Scenarios-Zonal Study) . The evaluation of multiple hydrologic conditions is expected to result in an appropriate integration level for tribal wind energy as supported by the accompanying economic analysis demonstrating mutual benefit.

Western's marketing of federal hydropower surpluses is an important piece of the financial structure of Pick-Sloan. In no event should Western eschew marketing federal hydropower generation and be marketing customer wind resources instead.

The amount of wind will be determined by the sustainable minimum/maximum amount of purchases in the system given high and low water conditions. This amount is being carefully determined, so as not to overlap with available hydro generation. Additionally, the ability to market excess hydro generation and concurrent excess wind generation will factor into the determination of an appropriate level of wind

integration. Work Element #2 addresses this issue. Should this effort eventually proceed to a demonstration project, criteria will need to be determined at that time how excess generation would be marketed so as to not negatively impact existing firm power customers and still provide mutual benefits.

The U.S. Army Corps of Engineers ("Corps") determines generation at the Pick-Sloan Missouri Basin Program main stem dams. The WHFS study must assess wind generation on a finer scale that hour to hour generation patterns. The WHFS study must also address the ability to integrate wind generation as a result of sudden changes in hydropower generation. Downstream precipitation can force the Corps will make rapid adjustments in generation to avoid downstream flooding. How will the study address this sort of scenario?

Hydro operational considerations will be part of the analysis and is included in Work Element #5. An appropriate generation pattern scale will be used to meet the established objectives of study.

The WHFS study appears not to recognize statutory limitations on the marketing of federal hydropower by firm power customers. The statutes and regulations surrounding the federal power program have been developed over many years and cannot be brushed aside in seeking to accommodate new missions for Western. To do so could divide Western's Pick-Sloan customers and threaten the viability of the Pick-Sloan Missouri Basin Program.

The WHFS approach has not identified any statutory limitations that may preclude a recommendation for a demonstration project. Western's statutory requirements would be considered as appropriate in any recommendations from this WHFS.

Mid-West recognizes Western's trust responsibility to Native American tribes. Under the Energy Planning and Management Program (EPAMP), Western has already provided additional allocations to Pick-Sloan tribes – an opportunity specifically prohibited for other Pick-Sloan customers. Western cannot and should not meet what it may consider trust responsibilities at the expense of its other firm power customers.

The Congressionally directed WHFS will asses three primary objectives; physical integration, operational integration and the economics associated with integration of Tribal wind energy. We believe any recommendation for a demonstration project would only be feasible if the WHFS supported favorable energy costs and or benefits to the customers of Western.

Sincerely,

Thomas P. Graves
Executive Director

APPENDIX B—WRITTEN COMMENTS

From: Matt Schuerger [mattschuerger@earthlink.net]
Sent: Friday, August 17, 2007 7:52 AM
To: 'Michael Radecki'
Cc: 'Brian Parsons'; 'Bradley Nickell'
Subject: Follow-up Comments RE: Conference Call Agenda Aug 9 07 12:00 Mountain / 1:00 Central

Good morning Mike,

As you requested at the end of the WHFS conference call on August 9th, I have outlined brief follow-up comments below which cover the questions and concerns that I raised during the call regarding the Draft Work Plan (Preliminary – July 11, 2007).

Key Recommendations – WHFS Draft Work Plan

1) Analyze Sufficient Levels of Total Wind Generation to Yield Meaningful Results

   The Section 2606 legislative language articulates a clear intent to analytically explore the potential technical and economic benefits of blending wind generation and Missouri River hydropower. These benefits arise from mitigation of potential system operating cost impacts due to the variability and uncertainty of wind generation. A number of recent studies have demonstrated that such operating and cost impacts are unlikely to be significant at wind penetrations up to 20% of system peak demand. For the Western Area Power Administration's Upper Great Plains region (approximately 3,500 MW control area load including approximately 2,000 MW of Western peak load), this threshold requires study of at least 400 MW of total wind generation.

   I recommend study of wind generation penetration levels of 20%, 30%, and 40% of Western system peak demand, corresponding to approximately 400 MW, 600 MW, and 800 MW of total wind generation (tribal and non-tribal wind within the control area).

2) Analyze Sub-Hourly Operating Impacts Using the Current Best Practices

   It's important to use the current best practices for the study of operating impacts of wind generation. Generally, these best practices include:

   - Capture system characteristics and response through operational simulations and modeling – this should include high quality modeling of the hydro system and it's capabilities in the relevant time frames.

- Develop and use multiple years of synthetic wind plant output time series data (based on large-scale meteorological modeling) , synchronized with load data for the same time period
- Capture wind deployment scenario geographic diversity through the synchronized weather simulation
- Couple with actual historic utility load and load forecasts
- Use actual large wind farm power statistical data for short-term regulation and ramping
- Examine wind variation in combination with load variations and hydro system capabilities
- Utilize wind forecasting best practice and combine wind forecast errors with load forecast errors
- Examine actual costs independent of tariff design structure

Please call me with any questions.

Thank you,

Matt Schuerger

From: Michael Radecki [mailto:Radecki@wapa.gov]
Sent: Friday, July 27, 2007 2:59 PM
To: Pat Spears; Tom Weaver; Karl Wunderlich; Matt Schuerger; Paulette Schaeffer; Warren Mackey; Mike Costanti; Brian Parsons; Jody S NWD02 Farhat; Trevor R NWO McDonald; Vic Simmons; FarrarRobert@stanleygroup.com; Robert Rusch; James Haigh; Walter Whitetail Feather; Bill Schumacher
Cc: Bob Gough; Tom Wind; Steve Wegman; Douglas Hellekson; Mark Messerli; Bradley Nickell; Stephen Tromly; Ed Weber
Subject: Conference Call Agenda Aug 9 07 12:00 Mountain / 1:00 Central

All,

Agenda for the August 9 conference call..

Please let me know if you have any questions.

Michael Radecki
Energy Services Specialist
Western Area Power Administration
Code 6210.BL
406-247-7442
FAX 406-247-7408
Radecki@wapa.gov

From: Matt Schuerger [mailto:mattschuerger@earthlink.net]
Sent: Monday, October 08, 2007 7:26 AM
To: 'Michael Radecki'
Cc: 'Tom Wind'; 'John Richards'; 'Steve Wegman'; 'Douglas Hellekson'; 'Mark Messerli'; 'Bradley Nickell'; 'Stephen Tromly'; 'Ed Weber'; 'Tom Weaver'; 'Karl Wunderlich'; 'Matt Schuerger'; 'Bob Gough'; 'Pat Spears alt'; 'Paulette Schaeffer'; 'Warren Mackey'; 'Mike McDowell'; 'Mike Costanti'; 'Dave Rich'; 'Brian Parsons'; 'Jody S NWD02 Farhat'; 'Trevor R NWO McDonald'; 'Vic Simmons'; Farrar, Robert; Rusch, Robert; 'James Haigh'; 'Walter Whitetail Feather'; 'Bill Schumacher'; 'Corbus, David'
Subject: RE: Work Plan Status ? -- WHFS

Good morning Mike,

I have received no response to the comments that I submitted to you on August 17th (attached).

How will Project Team comments be combined with public input and Federal Register comments (due Oct 19?) to develop the final work plan?

Please provide an update on the current status of the work plan and the process and schedule going forward.

Thank you,

Matt Schuerger

Matthew J. Schuerger, P.E.
Energy Systems Consulting, LLC
mattschuerger@earthlink.net
651-699-4971 (office)
651-231-1270 (cell)

From: DKates [dkates@sonic.net]
Sent: Friday, September 21, 2007 8:38 AM
To: UGPWindHydroFS@wapa.gov
Cc: 'Rex Wait (Rex Wait)'; 'Rob Bakondy'; 'Peter Lewandowski'; arlin.travis@morganstanley.com
Subject: Wind Hydropower Integration Feasibility Study

Please add me to the distribution list for the referenced study, and provide me with a copy of the study work plan.

Thank you very much. Please let me know if you have any questions.

David Kates
The Nevada Hydro Company
3510 Unocal Place, Suite 200
Santa Rosa, CA 95403
Telephone: (707) 570-1866
Fax: (707) 570-1867

Mid-West Electric Consumers Association

October 19, 2007

Mr. Robert Harris
Regional Manager
Upper Great Plains Region
Western Area Power Administration
2900 4th Avenue, North
Billings, MT 59101-1266

Dear Mr. Harris,

The Mid-West Electric Consumers Association appreciates the opportunity to comment on the Western Area Power Administration's ("Western") Draft Wind/Hydro Feasibility Study (WHFS) Project Work Plan, pursuant to Western's September 19, 2007 Federal Register notice.

The Mid-West Electric Consumers Association was founded in 1958 as the regional coalition of over 300 consumer-owned utilities (rural electric cooperatives, public power districts, and municipal electric utilities) that purchase hydropower generated at federal multi-purpose projects in the Missouri River basin under the Pick-Sloan Missouri Basin Program.

The Wind/Hydro Integration Feasibility Study (WHFS) is mandated by the Energy Policy Act of 2005 (EPAct2005). The instructions for the study, frankly, do not make sense. The legislative language seeks to explore "the economic and engineering feasibility of blending wind energy and hydropower generated from the Missouri River dams . . . including an assessment of the costs and benefits of blending wind energy and hydropower compared to current sources used for firming power to the Western Area Power Administration . . ."

All of the marketable hydropower in the Pick-Sloan Missouri Basin Program has been allocated to preference customers, including Native American Tribes. So, the only hydropower available for this "blending" would be the allocation of a tribe seeking to integrate its wind resource. EPAct2005 does permit the tribes to use their allocation for this purpose. Is that Pick-Sloan allocation sufficient to meet the engineering requirements of the blending of hydropower and wind energy envisioned by the study?

4350 Wadsworth Blvd., Suite 330, Wheat Ridge, CO 80033
Tel: (303) 463-4979 Fax: (303) 463-8876

It is not at all clear how using federal hydropower generation to firm Native American wind development will be able to then be used to firm the hydropower Western markets under the Pick-Sloan Missouri Basin Program. If this means that Western will be selling federal hydropower at cost-based rates and then re-buying a mix of wind and federally generated hydropower at market rates, the economics would clearly discriminate against Western's firm power customers.

The modeling that the study proposes must be conducted for a variety of hydrology conditions in the basin – both good water and bad. The study must address that range of generation scenarios in determining the amount of renewables that Western could purchase.

Western's marketing of federal hydropower surpluses is an important piece of the financial structure of Pick-Sloan. In no event should Western eschew marketing federal hydropower generation and be marketing customer wind resources instead.

The U.S. Army Corps of Engineers ("Corps") determines generation at the Pick-Sloan Missouri Basin Program main stem dams. The WHFS study must assess wind generation on a finer scale that hour to hour generation patterns. The WHFS study must also address the ability to integrate wind generation as a result of sudden changes in hydropower generation. Downstream precipitation can force the Corps will make rapid adjustments in generation to avoid downstream flooding. How will the study address this sort of scenario?

The WHFS study appears not to recognize statutory limitations on the marketing of federal hydropower by firm power customers. The statutes and regulations surrounding the federal power program have been developed over many years and cannot be brushed aside in seeking to accommodate new missions for Western. To do so could divide Western's Pick-Sloan customers and threaten the viability of the Pick-Sloan Missouri Basin Program.

Mid-West recognizes Western's trust responsibility to Native American tribes. Under the Energy Planning and Management Program (EPAMP), Western has already provided additional allocations to Pick-Sloan tribes – an opportunity specifically prohibited for other Pick-Sloan customers. Western cannot and should not meet what it may consider trust responsibilities at the expense of its other firm power customers.

Sincerely,

Thomas P. Graves
Executive Director

From: Tim Williamson [TimWilliamson@frontiernet.net]
Sent: Friday, October 19, 2007 6:35 PM
To: UGPWindHydroFS@wapa.gov
Subject: Response to Request for Public Comment

Dear Upper Great Plains Wind/Hydro Feasibility Study,

FreedomWorks, LLC provides the following response to Feasibility Study Request for Public Comment:

Existing generation capacity exists in Montana to replenish WAPA capacity loses as a result of last seven years drought.

Request consideration of alternate wind energy solution with small business FreedomWorks, LLC to maximum Northwestern Energy eastbound ATC available at Crossover, MT, to augment existing hydropower provided by Yellowknife Power Plant. FreedomWorks, LLC requests accommodation within in the WAPA Wind/Hydro Feasibility Study for the express purpose of providing 800 MW renewable wind energy power generation, on near short term contract basis to Western Federal Power Loads in response to EPACT 2005, E.O. 13423 and pending energy policy act of 2008.

FreedomWorks proposes to provide 2,926,000 MWh annual generation capacity to WAPA, on short term PPA, to bridge current western drought and duration necessary to accomplish MSTI, MATL and BPA congestion resolution installation(s). Upon accomplishment of these projects, FreedomWorks shall shift proposed short term Western PPA to MSTI, MATL and BPA power loads as capacity becomes available. The intent of this comment is to request consideration of a non-tribal, corporate American small business wind renewable energy solution, until tribal wind becomes viable.

Tim Williamson

FreedomWorks, LLC

525 Wren Lane

Harpers Ferry, WV 25425

Tel: (304) 728-7951

Fax: (304) 728-7951

Mobile: (202) 369-6324

From: Tim Williamson [TimWilliamson@frontiernet.net]
Sent: Saturday, October 20, 2007 5:41 AM
To: UGPWindHydroFS@wapa.gov
Subject: RE: Response to Request for Public Comment

All,

Please note a correction reference to Yellowtail Power Plant, in lieu of previously provided Yellowknife Power Plant.

Tim Williamson

FreedomWorks, LLC

525 Wren Lane

Harpers Ferry, WV 25425

Tel: (304) 728-7951

Fax: (304) 728-7951

Mobile: (202) 369-6324

Please see WHFS webpage at

http://www.wapa.gov/UGP/PowerMarketing/WindHydro/Default.htm

for meeting minutes (including public comments) of the September 27, 2007 Public Meeting.

APPENDIX C—WIND DEMONSTRATION PROJECT QUESTIONNAIRE

Wind Demonstration Project Questionnaire
EPAct 2005, Title XXVI, Section 2606
Date of Issue: ___________ Date of Return:________________

Please provide as much of the information requested below as possible. This questionnaire includes a detailed listing of issues required when developing a wind farm project. Projects at various stages of development will have different levels of data available. As we evaluate projects for the Wind and Hydropower Feasibility Study (WHFS) Wind Demonstration Project, priority will be given to projects that have comprehensive proposal information. The amount of information provided will provide an indicator for the level of development to date. For any project information considered confidential, please indicate within [ ] to clearly identify information that you would like to remain confidential.

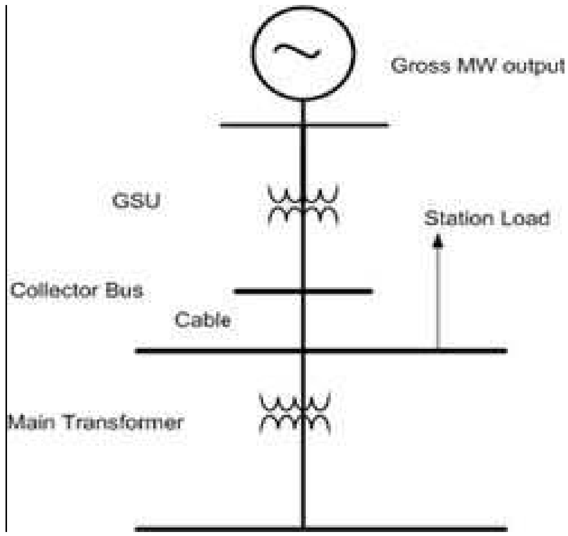
Please review EPAct 2005, Title XXVI, Section 2606 for details on the requirements of the Wind and Hydropower Feasibility Study. For more information on the WHFS Wind Demonstration Project, you may contact Michael Radecki, Energy Services Specialist, Western Area Power Administration, 406 247 7408 radecki@wapa.gov.

Please return completed questionnaires to Michael Radecki, Energy Services Specialist, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101-1266. Please sign and date the completed questionnaire on page 7.

Completed questionnaires must be returned by _____________ in order to be included in the modeling analysis.

Contact Information:	
Project Name	
Tribe	
Contact Name	
Title	
Phone	
Email	

Project Description:	
Brief description of project including total nameplate at build out to be completed prior to 12/31/2010	**Total Nameplate Capacity:________ MW** **Expected In-Service Date: _____________** **State and Quadrant of Location (e.g., NW quadrant of NE): ________________** **Approximate size of Development: ________________acres**
Phasing:	
If additional nameplate capacity will be added after 12/31/2010 please provide staging information including expected in-service date and nameplate of phases (Please number phases)	**Phase ____: _____MW In-Service Date: ________** **Phase ____: _____MW In-Service Date: ________** **Phase ____: _____MW In-Service Date: ________**
Location:	
Provide encompassing longitude and latitude of each discrete site with a reference name for each site listed; also list phase number by site, if appropriate	**Site Name: ____________________(Phase ____)** **Encompassing Latitude and Longitude** _______________________________________ _______________________________________



Interconnection Information (refer to diagram):	
Maximum gross output (Nameplate per turbine x number of turbines)	**______ MW x________ Turbines = _________MW**
GSU MW Losses	**______MW**
Station Service Load (MW/MVAR)	**______MW ________MVAR**
Maximum net output (Gross MW Output - GSU MW Losses – Station Service MW Load)	**______MW**
Proposed point(s) of interconnection (if multiple points, please list in order of preference)	**Transmission line segment or closest substation:** ____ **Voltage: _____kV** **Approximate Distance from point of connection to Main Transformer: ___________________miles**
Site Plan on USGS topo map, tax map, etc.	**Provided: Yes ______ No _______**
One line diagram of facility electrical arrangement	**Provided: Yes ______ No _______**

Turbine Data:	
Type of turbine (Please provide a brief description of wind generator, e.g., GE doubly fed induction machine with back-to-back IGBT converters or Micon induction generator, etc.)	
MW Size of each turbine:	**______MW**
MVA Base of each turbine:	**______MVA**
Number of turbines	
Terminal Voltage	**_____kV**
Control Mode (Voltage Control or Power Factor Control-if Power Factor Control provide Power Factor range at generator terminal)	**Voltage Control: Yes _____ No _____** **Power Factor Control-Range at Generator Terminal: ____**
VAR Support	**Size, location, type (regular/switching shunts & steps) of additional capacitors:___________________________** **Size, location of dynamic VAR: _________________**
Collector system layout data	**Provided: Yes ______ No _______**

If available, please provide additional information specific to design as indicated in Appendix A.

Production Cost Modeling Information:	
Wind data for site including measured or modeled data with description of source and comments on spatial diversity of turbines on site to maximize output	**Number of wind measurement stations: _______** **Length of time in place:__________ years** **Hub heights: ___________** **Wind profile measurements (i.e., wind shear)— If yes, please attach description:** **If modeling, please attach description:** **Attachment provided for profile measurements:** **Yes ______ No _______** **Attachment provided for modeling:** **Yes ______ No _______**
Maintenance plan (Please specify either anticipated schedule or number of hours per month expected and provide information on expected cost of outages due to maintenance)	**Attachment provided:** **Yes ______ No _______**
Storage capability (batteries on site, plans for pumped storage facility, etc.) or other features that would provide firming characteristics	**Attachment provided:** **Yes ______ No _______**
Estimated monthly capacity factor (or annual if monthly not available) suggested for site and description of methodology used	**Attachment provided:** **Yes ______ No _______**

Pro Forma Analysis (If submitting a pro forma analysis, indicate “pro forma attached” on relevant questions below):	
Anticipated hourly average output (MW per hour for a year or typical day patterns by month)	**Attachment provided:** **Yes ______ No _______**
Projected operating costs	**$ _____ O&M** **$ _____ Warranty/Replacement** **$ _____ Property & Insurance**
Assumptions related to firm/non-firm and curtailment decisions used in cost estimate; has conditional curtailment been considered?	**Attachment provided:** **Yes ______ No _______**
Projected installed cost per MW	**$ ____ per MW**
Expected tax credit/tax exempt vehicles to be used to achieve expected financing structure (e.g., CREB, PTC, flip, etc.)	**Attachment provided:** **Yes ______ No _______**
Value associated with Tradable Renewable Certificates	**Attachment provided:** **Yes ______ No _______**
Are there net metering or behind the metering opportunities available to displace on-site energy costs that could be incorporated into the project?	**If yes, please describe type of on-site energy required (e.g., HVAC, industrial) and approximate capacity/energy that could be displaced.** **Attachment provided:** **Yes ______ No _______**
Required after-tax internal rate of return for investors	**Type of investor: ___________** **Required IRR: _____________%**
Projected Total Cost per MW	**$ _________ per MW**
Contract Energy Price (i.e., revenue required) to arrive at the minimum amount of revenue to meet debt requirements and/or rate of return requirements	**$ _________ per MWh**
Please describe results and methodology of any production cost models (e.g., monthly/seasonal output, expected energy, capacity values) and how the information has been used in pro forma analysis	**Attachment provided:** **Yes ______ No _______**

Project Development Status:	
Project timeline with significant milestones through construction and commissioning	**Attachment provided:** **Yes ______ No _______**
Financial commitments in place (Please indicate nature and percent of project costs covered by existing commitments)	**Attachment provided:** **Yes ______ No _______**
Any agreements signed related to proposed project—please list name and nature of agreement	**Attachment provided:** **Yes ______ No _______**
Tribal approval process and status	**Attachment provided:** **Yes ______ No _______**
Describe project development steps taken to date regarding site control, wind studies, environmental assessments, transmission service requests, etc. Indicate if studies are required and/or what studies are ongoing or completed	**Attachment(s) provided:** **Yes ______ No _______** **Please list attachments provided:**
Please list any known or suspected issues or complications with project siting	**Attachment provided:** **Yes ______ No _______**

Additional comments and information for consideration:

Completed by (please print) **Signature** **Date**

Appendix A

Induction Generators:	
Rotor Resistance:	
Stator Resistance:	
Stator Reactance:	
Rotor Reactance:	
Magnetizing Reactance:	
Total Rotating Inertia, H:	_______ per unit on KVA base
Generator exciter and governor data sheets, if available	

Wind Farm Design Specifics:	
Cable length for Wind Farm Collection System	
Cable Type and Impedance per mile	
Embedded Relay for each turbine (Yes or No)	
Voltage relay (Yes or No)	
Manufacturer default voltage relay setting	
Frequency relay (Yes or No)	
Manufacturer default frequency relay setting	

Wind Turbine GSU (each turbine):	
Generator Step-Up Transformer MVA Base	
Generator Step-Up Transformer Impedance (R+jX or % on transformer MVA base)	
Generator Step-Up Transformer Reactance-to-Resistance Ratio (X/R)	
Generator Step-Up Transformer Rating (MVA)	
Generator Step-Up Transformer Low-side Voltage (kV)	
Generator Step-Up Transformer High-side Voltage (kV)	
Generator Step-Up Transformer Off-nominal turns ratio	
Generator Step-Up Transformer Number of Taps and Step Size	

Wind Farm Transformer Data:	
Generator Step-Up Transformer MVA Base	
Generator Step-Up Transformer Impedance (R+jX or % on transformer MVA base)	
Generator Step-Up Transformer Reactance-to-Resistance Ratio (X/R)	
Generator Step-Up Transformer Rating (MVA)	
Generator Step-Up Transformer Low-side Voltage (kV)	
Generator Step-Up Transformer High-side Voltage (kV)	
Generator Step-Up Transformer Off-nominal turns ratio	
Generator Step-Up Transformer Number of Taps and Step Size	

Appendix C

WHFS Wind Demonstration Project Questionnaire

Wind Demonstration Project Questionnaire
EPAct 2005, Title XXVI, Section 2606
Date of Issue: ___________ Date of Return:________________

Please provide as much of the information requested below as possible. This questionnaire includes a detailed listing of issues required when developing a wind farm project. Projects at various stages of development will have different levels of data available. As we evaluate projects for the Wind and Hydropower Feasibility Study (WHFS) Wind Demonstration Project, priority will be given to projects that have comprehensive proposal information. The amount of information provided will provide an indicator for the level of development to date. For any project information considered confidential, please indicate within [ ] to clearly identify information that you would like to remain confidential.

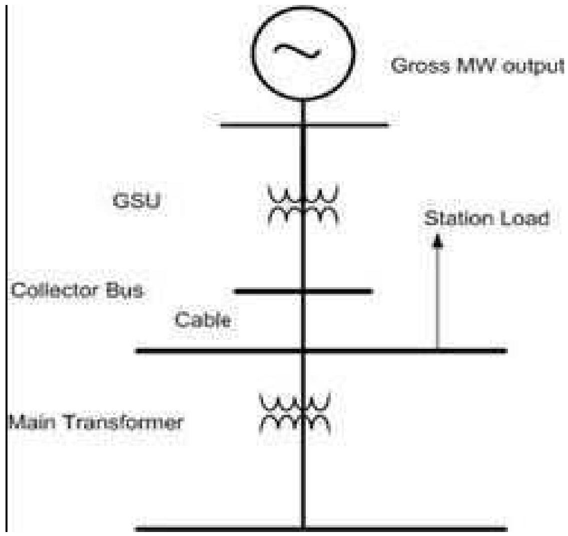
Please review EPAct 2005, Title XXVI, Section 2606 for details on the requirements of the Wind and Hydropower Feasibility Study. For more information on the WHFS Wind Demonstration Project, you may contact Michael Radecki, Energy Services Specialist, Western Area Power Administration, 406 247 7408 radecki@wapa.gov.

Please return completed questionnaires to Michael Radecki, Energy Services Specialist, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101-1266. Please sign and date the completed questionnaire on page 7.

Completed questionnaires must be returned by _____________ in order to be included in the modeling analysis.

Contact Information:	
Project Name	
Tribe	
Contact Name	
Title	
Phone	
Email	

Project Description:	
Brief description of project including total nameplate at build out to be completed prior to 12/31/2010	**Total Nameplate Capacity:________ MW** **Expected In-Service Date: _____________** **State and Quadrant of Location (e.g., NW quadrant of NE): ________________** **Approximate size of Development: ________________acres**
Phasing:	
If additional nameplate capacity will be added after 12/31/2010 please provide staging information including expected in-service date and nameplate of phases (Please number phases)	**Phase ____: _____MW In-Service Date: ________** **Phase ____: _____MW In-Service Date: ________** **Phase ____: _____MW In-Service Date: ________**
Location:	
Provide encompassing longitude and latitude of each discrete site with a reference name for each site listed; also list phase number by site, if appropriate	**Site Name: ____________________(Phase ____)** **Encompassing Latitude and Longitude** _______________________________________ _______________________________________



Interconnection Information (refer to diagram):	
Maximum gross output (Nameplate per turbine x number of turbines)	**______ MW x________ Turbines = _________MW**
GSU MW Losses	**______MW**
Station Service Load (MW/MVAR)	**______MW ________MVAR**
Maximum net output (Gross MW Output - GSU MW Losses – Station Service MW Load)	**______MW**
Proposed point(s) of interconnection (if multiple points, please list in order of preference)	**Transmission line segment or closest substation:** ____ **Voltage: _____kV** **Approximate Distance from point of connection to Main Transformer: ___________________miles**
Site Plan on USGS topo map, tax map, etc.	**Provided: Yes ______ No _______**
One line diagram of facility electrical arrangement	**Provided: Yes ______ No _______**

Turbine Data:	
Type of turbine (Please provide a brief description of wind generator, e.g., GE doubly fed induction machine with back-to-back IGBT converters or Micon induction generator, etc.)	
MW Size of each turbine:	**______MW**
MVA Base of each turbine:	**______MVA**
Number of turbines	
Terminal Voltage	**_____kV**
Control Mode (Voltage Control or Power Factor Control-if Power Factor Control provide Power Factor range at generator terminal)	**Voltage Control: Yes _____ No _____** **Power Factor Control-Range at Generator Terminal:** ____
VAR Support	**Size, location, type (regular/switching shunts & steps) of additional capacitors:_____________________________** **Size, location of dynamic VAR: __________________**
Collector system layout data	**Provided: Yes ______ No _______**

If available, please provide additional information specific to design as indicated in Appendix A.

Production Cost Modeling Information:	
Wind data for site including measured or modeled data with description of source and comments on spatial diversity of turbines on site to maximize output	**Number of wind measurement stations: _______** **Length of time in place:__________ years** **Hub heights: ___________** **Wind profile measurements (i.e., wind shear)— If yes, please attach description:** **If modeling, please attach description:** **Attachment provided for profile measurements:** **Yes ______ No _______** **Attachment provided for modeling:** **Yes ______ No _______**
Maintenance plan (Please specify either anticipated schedule or number of hours per month expected and provide information on expected cost of outages due to maintenance)	**Attachment provided:** **Yes ______ No _______**
Storage capability (batteries on site, plans for pumped storage facility, etc.) or other features that would provide firming characteristics	**Attachment provided:** **Yes ______ No _______**
Estimated monthly capacity factor (or annual if monthly not available) suggested for site and description of methodology used	**Attachment provided:** **Yes ______ No _______**

Pro Forma Analysis (If submitting a pro forma analysis, indicate "pro forma attached" on relevant questions below):	
Anticipated hourly average output (MW per hour for a year or typical day patterns by month)	**Attachment provided:** **Yes ______ No _______**
Projected operating costs	**$ _____ O&M** **$ _____ Warranty/Replacement** **$ _____ Property & Insurance**
Assumptions related to firm/non-firm and curtailment decisions used in cost estimate; has conditional curtailment been considered?	**Attachment provided:** **Yes ______ No _______**
Projected installed cost per MW	**$ ____ per MW**
Expected tax credit/tax exempt vehicles to be used to achieve expected financing structure (e.g., CREB, PTC, flip, etc.)	**Attachment provided:** **Yes ______ No _______**
Value associated with Tradable Renewable Certificates	**Attachment provided:** **Yes ______ No _______**
Are there net metering or behind the metering opportunities available to displace on-site energy costs that could be incorporated into the project?	**If yes, please describe type of on-site energy required (e.g., HVAC, industrial) and approximate capacity/energy that could be displaced.** **Attachment provided:** **Yes ______ No _______**
Required after-tax internal rate of return for investors	**Type of investor: ___________** **Required IRR: _____________%**
Projected Total Cost per MW	**$ _________ per MW**
Contract Energy Price (i.e., revenue required) to arrive at the minimum amount of revenue to meet debt requirements and/or rate of return requirements	**$ _________ per MWh**
Please describe results and methodology of any production cost models (e.g., monthly/seasonal output, expected energy, capacity values) and how the information has been used in pro forma analysis	**Attachment provided:** **Yes ______ No _______**

Project Development Status:	
Project timeline with significant milestones through construction and commissioning	**Attachment provided:** **Yes ______ No _______**
Financial commitments in place (Please indicate nature and percent of project costs covered by existing commitments)	**Attachment provided:** **Yes ______ No _______**
Any agreements signed related to proposed project—please list name and nature of agreement	**Attachment provided:** **Yes ______ No _______**
Tribal approval process and status	**Attachment provided:** **Yes ______ No _______**
Describe project development steps taken to date regarding site control, wind studies, environmental assessments, transmission service requests, etc. Indicate if studies are required and/or what studies are ongoing or completed	**Attachment(s) provided:** **Yes ______ No _______** **Please list attachments provided:**
Please list any known or suspected issues or complications with project siting	**Attachment provided:** **Yes ______ No _______**

Additional comments and information for consideration:

Completed by (please print) **Signature** **Date**

Appendix A

Induction Generators:	
Rotor Resistance:	
Stator Resistance:	
Stator Reactance:	
Rotor Reactance:	
Magnetizing Reactance:	
Total Rotating Inertia, H:	________ per unit on KVA base
Generator exciter and governor data sheets, if available	

Wind Farm Design Specifics:	
Cable length for Wind Farm Collection System	
Cable Type and Impedance per mile	
Embedded Relay for each turbine (Yes or No)	
Voltage relay (Yes or No)	
Manufacturer default voltage relay setting	
Frequency relay (Yes or No)	
Manufacturer default frequency relay setting	

Wind Turbine GSU (each turbine):	
Generator Step-Up Transformer MVA Base	
Generator Step-Up Transformer Impedance (R+jX or % on transformer MVA base)	
Generator Step-Up Transformer Reactance-to-Resistance Ratio (X/R)	
Generator Step-Up Transformer Rating (MVA)	
Generator Step-Up Transformer Low-side Voltage (kV)	
Generator Step-Up Transformer High-side Voltage (kV)	
Generator Step-Up Transformer Off-nominal turns ratio	
Generator Step-Up Transformer Number of Taps and Step Size	

Wind Farm Transformer Data:	
Generator Step-Up Transformer MVA Base	
Generator Step-Up Transformer Impedance (R+jX or % on transformer MVA base)	
Generator Step-Up Transformer Reactance-to-Resistance Ratio (X/R)	
Generator Step-Up Transformer Rating (MVA)	
Generator Step-Up Transformer Low-side Voltage (kV)	
Generator Step-Up Transformer High-side Voltage (kV)	
Generator Step-Up Transformer Off-nominal turns ratio	
Generator Step-Up Transformer Number of Taps and Step Size	

Appendix D

3Tier Inception Report

INCEPTION REPORT
FOR
STANLEY CONSULTANTS

3TIER
knowledge is power

August 8, 2008

Contents

A. Overview

The scope of work associated with this report required the production of two sets of time-series wind energy data for specified hypothetical wind plants in the north-central United States. The two simulations performed, hereafter referred to as Phase 1 and Phase 2, are distinguished by the geographic region covered, the time period simulation, the location of the hypothetical wind plants, and the temporal resolution of the simulation.

The data sets created for this project are designed with the expectation that the data will be used for an integration study. As such, the raw model time series data are extracted from a 5km horizontal resolution simulation, which is well suited for capturing the general temporal fluctuations at the proposed plant locations. The raw model data are then further processed using a statistical technique in order to better represent short time scale power fluctuations (see Section C), which is very important for integration studies.

The raw model data have been compared to on-site observational data at multiple sites within the study area. The purpose of the validation analysis is to ensure that the model data represent the prevailing flow conditions across the study area, and to understand any potential biases between the observed and modeled data. The validation analysis reveals that the model data, on average, tend to underestimate the observed on-site observational data.

The focus of this document is to describe the methodology used in creating the data sets, including specific information regarding modeling, parameters and approaches of converting wind speed to power output.

B. SIMULATION PARAMETERS

The specifications for each set of data are provided in Table 1, as dictated by Stanley Consultants. The specifications for the wind plants for Phase 1 and Phase 2 are provided in Tables 2, 3, and 4 below.

Table 1. Simulation Specifications

Specification	Phase 1	Phase 2
Time Begin	January 1, 2000, 00:00 UTC	March 1, 2007, 00:00 CST
Time End	December 31, 2000, 23:00 UTC	February 29, 2008, 23:50 CST
Temporal Granularity	Hourly	10 minutes
Number of Sites	22	37
Additional Requested Sites	14[1]	N/A

Table 2. Phase 1 Wind Plant Specifications

Wind Plant ID	Longitude	Latitude	Turbine Hub Height (m)	Year 2010 Capacity (MW)	Post-2010 Capacity (MN)
FtPeck1	*	*	80	39	320
FtPeck2	*	*	80	39	320
FtPeck3	*	*	80	39	320
Cheyenne1	*	*	80	99	199.5
Cheyenne2	*	*	80	99	199.5
Cheyenne3	*	*	80	99	199.5
Blackfeet	*	*	80	50	50
RoseFrancis1	*	*	80	30	110
RoseFrancis2	*	*	80	30	110
FourWinds	*	*	80	10	40
StandRock1	*	*	80	120	120
StandRock2	*	*	80	120	120
StandRock3	*	*	80	120	120
FtBerthold	*	*	80	50	50
Rosebud	*	*	80	50	50
SpiritLake	*	*	80	50	50
Flandreau1	*	*	80	50	50
Flandreau2	*	*	80	50	50
LowerBrule	*	*	80	50	50
PinkeRidge	*	*	80	50	50
Yankton	*	*	80	50	50
Omaha	*	*	80	50	50

*Not included to protect location confidentiality.

[1] Additional data were delivered in CST time zone, not UTC.

Table 3. Additional Phase 1 Wind Plant Specifications

Wind Plant ID	Longitude	Latitude	Turbine Hub Height (m)	Year 2011 Capacity (MW)
Just Wind-2	*	*	80	50
Just Wind-4	*	*	80	50
PPMBuffaloRidge-2	*	*	80	50
PPMBuffaloRidge-4	*	*	80	50
PPMLowerBrule-2	*	*	80	50
PPMLowerBrule-4	*	*	80	50
WessingtonSprings	*	*	80	50
BasinND-1	*	*	80	57.5
BasinND-2	*	*	80	57.5
BasinSD-1	*	*	80	50
BasinSD-2	*	*	80	50
Basin Pomona	*	*	80	40
Basin Hyde	*	*	80	40
Basin Ecklund	*	*	80	50

*Not included to protect location confidentiality.

Table 4. Phase 2 Wind Plant Specifications

Wind Plant ID	Longitude	Latitude	Turbine Hub Height (m)	Year 2011 Capacity (MW)
Blackfeet	*	*	80	50
Cheyenne-1	*	*	80	33
Cheyenne-2	*	*	80	33
Cheyenne-3	*	*	80	33
FtPeck-1	*	*	80	13
FtPeck-2	*	*	80	13
FtPeck-3	*	*	80	13
ICOUP-Flandreau-1	*	*	80	25
ICOUP-Flandreau-2	*	*	80	25
ICOUP-FtBerthold	*	*	80	50
ICOUP-LowerBrule	*	*	80	50
ICOUP-PineRidge	*	*	80	50
ICOUP-Rosebud	*	*	80	50
ICOUP-SpiritLake	*	*	80	50
ICOUP-Yankton	*	*	80	50
RoseFrancis-1	*	*	80	15
RoseFrancis-2	*	*	80	15
StandRock-1	*	*	80	50
StandRock-2	*	*	80	20
StandRock-3	*	*	80	50
JustWind-1	*	*	80	50
JustWind-2	*	*	80	50
JustWind-3	*	*	80	50
JustWind-4	*	*	80	50
PPMBuffaloRidge-1	*	*	80	50
PPMBuffaloRidge-2	*	*	80	50
PPMBuffaloRidge-3	*	*	80	50
PPMBuffaloRidge-4	*	*	80	50
PPMLowerBrule-1	*	*	80	50
PPMLowerBrule-2	*	*	80	50
PPMLowerBrule-3	*	*	80	50
PPMLowerBrule-4	*	*	80	50
WessingtonSprings	*	*	80	50
BasinND-1	*	*	80	57.5
BasinND-2	*	*	80	57.5
BasinSD-1	*	*	80	50
BasinSD-2	*	*	80	50

*Not included to protect location confidentiality.

To generate each set of data, 3TIER first selected, configured, and ran a Numerical Weather Prediction (NWP) model. Each NWP model simulation produced a time-series of wind data. These data were later used to generate a representative time-series of wind plant power output. The selection of the specific NWP model used in each simulation and the configuration thereof was done at 3TIER's discretion and is sensitive to the geographic region simulated, period simulated and model performance. The significant simulation parameters are displayed in Table 5. The simulation regions for each phase are shown in Figure 1 and Figure 2, respectively.

Table 5. NWP Model Simulation Parameters

Simulation Parameter	Phase 1	Phase 2
Mesoscale NWP Model	WRF[2]2.1	WRF[1]3.0
Configuration Notes	Standard	Standard with grid nudging
Horizontal Resolution of Study Area	5 km	5 km
Number of Vertical Levels	31	31
Elevation Database	3 arcsecond SRTM[3]	3 arcsecond SRTM[2]
Vegetation Database	30 arcsecond USGS[4]	30 arcsecond USGS[3]
Soil Classification	30 arcsecond USGS[3]	30 arcsecond USGS[3]
Surface Parameterization	Monin-Obukhov similarity model	Monin-Obukhov similarity model
Boundary Layer Parameterization	YSU[5] model	YSU[4] model
Land Surface Scheme	5-layer soil diffusivity model	5-layer soil diffusivity model
Domain Boundary Coordinates:	113.50W, 96.00W, 41.60N, 49.00N	113.20W, 96.00W, 42.60N, 49.00N
Off-Site Observations	None	None

[2] Skamarock, W.C., J.B. Klemp, J. Dudhia, D.O. Gill, D.M. Barker, W. Wang, J.G. Powers, 2005: *A description of the Advanced Research WRF Version 2*. NCAR Technical Note, NCAR/TN-468+STR, Boulder, Colorado, 88p.

[3] SRTM: Shuttle Radar Topography Mission; additional information available at http://www2.jpl.nasa.gov/srtm/

[4] USGS: U.S. Geological Survey

[5] YSU: Yonsei University scheme; Skamarock et al. 2005

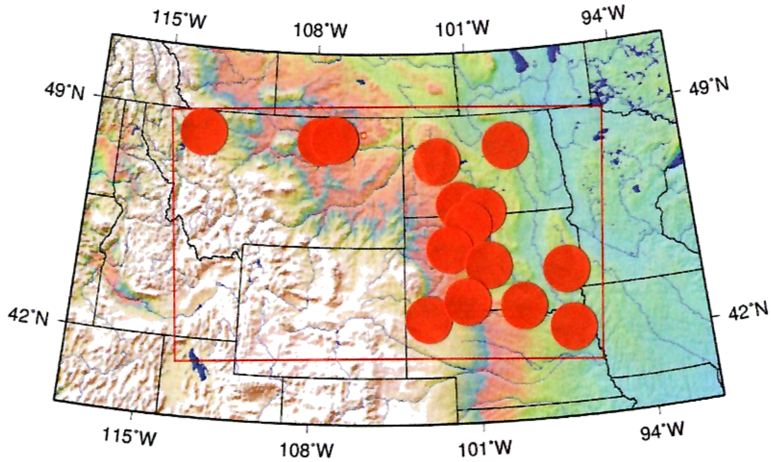


Figure 1. Domain utilized for Phase 1 with wind plant locations identified.

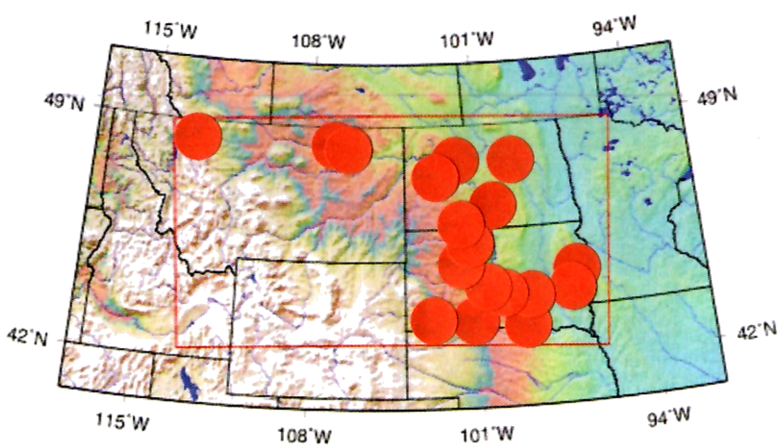


Figure 2. Domain utilized for Phase 2 with wind plant locations identified.

C. Power Conversion Methodologies

Due to the difference in temporal granularity of the NWP simulations, two different wind speed-to-power conversion methodologies were employed. The coarse hourly temporal granularity of Phase 1 allowed for a direct deterministic conversion of power from wind speed by way of the manufacturer's power curve. The turbine selected by Stanley Consultants and used in the study is the GE SLE 1.5 MW wind turbine. The power output of the wind plant was determined by multiplying the single turbine power output by the number of wind turbines in each wind plant (see Tables 2-4).

The data were produced such that each model grid point represented a number of turbines and the number of grid points per project could be scaled up or down to adjust the total capacity of the project. The loss factor, often used in modeling studies, has been implicitly included in this dataset. The modeling for this dataset does not allow for turbines being placed in the optimal sub-grid locations (which by definition would experience higher wind speeds than the average wind speed over the model grid point). Furthermore, the use of SCORE-lite (explained below) also implicitly includes some small loss factors that represent the difference between the theoretical power output given a certain wind speed and the actual power output observed over time.

The ten-minute granularity of Phase 2 dictates that a different wind speed-to-power conversion approach be taken. The main reason for this is that the wind speed from NWP model simulations tends to be smoother than is observed in reality. Representing the variations in data sets with hourly temporal granularity is not necessary, as the variations would tend to be smoothed in the averaging process. However, at ten-minute intervals, the variations are of consequence and must be represented. To account for the variations, the Statistical Correction to Output from a Record Extension (SCORE)-Lite technique was employed. The SCORE-Lite is used in preference over the SCORE method when the locations of turbines within a wind plant are not known, as in the case with Phase 1 and Phase 2. SCORE-Lite does not model each turbine individually, but instead models the number of turbines that could be associated with each grid point of the NWP model in a practical manner.

The premise of SCORE-Lite is to add a random component to a time series of wind plant power output (using the same method as in Phase 1). The random component introduces realistic ten-minute variability in power production. The value of the random component is drawn from a Probability Density Function (PDF). To produce the PDF used in SCORE-Lite, data from actual wind turbines are first used to produce a PDF for a typical wind turbine. The wind turbine PDFs are combined, based on the number of wind turbines associated with an NWP grid point, to create an aggregated PDF. This PDF is used in SCORE-Lite. Therefore, SCORE-Lite PDF represents not one turbine, but all turbines within an NWP model grid. This results in a narrower range of deviations in the cumulative PDF because the aggregate power production of several turbines is smoother than that of one turbine and adheres more closely to the manufacturer's power curve. The result is a ten-minute time-series of wind plant power output whose variability mimics that of actual wind plants.

Implicit in the method is the assumption that the wind power plants being modeled will exhibit similar variability characteristics as the power plants from which the PDF was developed. 3TIER's experience with SCORE suggests that this is a reasonable assumption – especially when compared with the alternative of using a basic rated power curve.

Appendix E

EnerNex Memorandum of Regulating Reserve Estimation Methodology

EnerNex CORPORATION

MEMORANDUM

To: Kim Massey – Stanley Consultants

From: Bob Zavadil

Date: September 15, 2008

Subject: Description of Regulating Reserve Estimation Methodology.

The purpose of this document is to describe the analytical approach used to determine how WAPA operating reserve requirements would be affected by the addition of wind generation to the control area. The results for each scenario are to be mapped to the reserve categories in PROMOD IV, and be carried forward as constraints in the annual production simulations.

The analysis used high resolution (30 second and 10 minute) load and (existing) wind energy production data provided by WAPA. Synthesized wind energy production data at 10 minute intervals for the same historical year as the archived data was developed by 3Tier.

This analysis was based on the following wind configuration in Western's control area: Existing wind 130 MW large wind plus 28 MW small wind (no data available), Proposed non-tribal wind, 564 MW, Tribal Wind 50 MW for a total base scenario of 723 MW and tribal scenario of 773 MW. Based upon a system peak of 3090 MW, these scenarios represent wind nameplate penetrations of 23% and 25% respectively.

The recommendations for reserve requirements described in this analysis are specific to the combined wind resources used in this study. Although representative of the reserves required when integrating this capacity of wind onto the system and appropriate for use in PROMOD IV production cost models, an analysis specific to actual wind plant locations and variability will need to be performed when proposed wind is ready to be injected onto Western's system.

Of the proposed non-tribal wind, 300 MW (3-100 MW sites) will be in a mid-term contract due to expire shortly after the initial 2011 scenario.

Hence, 350 MW of tribal wind is possible after the mid-term contract expires. A reserve requirement for the change from 3-100 MW sites to potentially 6-50 MW tribal sites will vary from that described in this report, but the large wind sites should provide a more conservative reserve requirement. The increased geographic diversity incorporated with 6 smaller sites should reduce variability due to wind, possibly lowering the reserve requirements specified.

The method is empirical in nature, in that it stems from the NERC Control Performance Standards and adjusts the quantity of flexible generation required for this balancing each hour.

Background

The common methodology for assessing the cost of integrating wind energy into a utility control area is based on chronological simulations of scheduling and real-time operations. Production costing and other optimization tools are generally used to conduct these simulations. In most cases, the "time-step" for these simulations is in one-hour increments. Consequently, many details of real-time operation cannot be simulated explicitly. Generation capacity that is used by operators to manage the system in real-time – i.e. the units on AGC utilized by the EMS for both fast response to ACE and that which is frequently economically re-dispatched to follow changes in control area demand – is assigned to one or more reserve categories available in the various programs.

At this level of granularity, the total reserve requirements for the system are a constraint on the optimization and dispatch. Supply resources in the model are designated by their ability to contribute to the system requirements in one or more reserve categories. In the course of the optimization or dispatch, the solution algorithm must honor the system reserve needs, and therefore is not able to use some capacity to meet load or fulfill transactions.

In this context, there are two primary types of reserves. The first is comprised of the excess capacity that must be carried at all times for reliability. These are generally known as "contingency reserves", and as the name implies, can only be utilized when an event that meets the definition of a contingency actually occurs.

The second category of reserves is used to balance the supply with the control area demand on a continuous basis. This includes minute-by-minute (or faster) adjustments to generation to compensate for load variations and frequency economic dispatch of units with movement capability to follow slower variations in control area demand.

The analysis focuses on three elements of real-time operations

- Estimating the amount of fast-responding reserve capacity will be required to meet balancing area frequency control obligations with wind generation on the system. This capacity is adjusted both up and down on a minute-by-minute (or thereabouts) basis. Generation on AGC is dispatched automatically to compensate for random deviations in the balancing area demand around the slower trend characteristic (e.g. upward trend during the morning ramp).
- Establishing the amount of controllable generation required each hour to compensate for deviations of the ten-minute control area demand from an hourly average.
- Determining how much additional capacity must be available to offset errors and uncertainty in short-term load and wind generation forecasts.

The variability of wind generation on operational time frames – minutes, tens of minutes, hours – will increase the variability of the control area demand. The amounts of various types of reserve generation required to compensate for variability will be increased. Figure 1 illustrates the NREC "Interconnected Operations Services", where Regulation and Load Following are of primary interest here (Figure 1). It should be noted that wind generation does not, in general, affect the requirements for contingency reserve.

A glossary of NERC terminology from the IOS Reference Document is included at the end of this report.

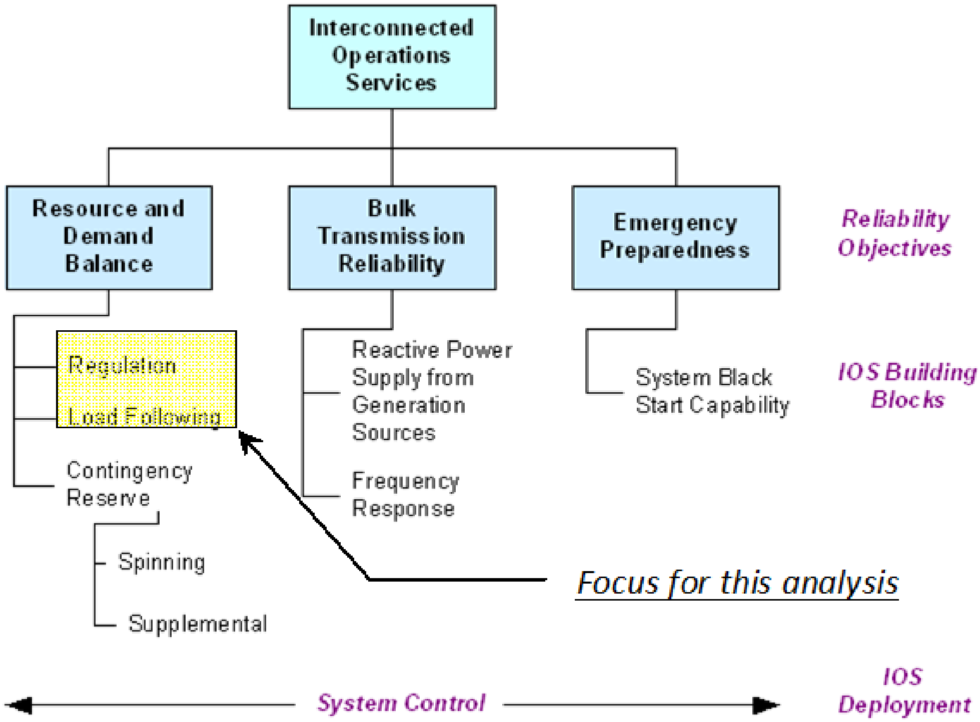


Figure 1: NERC Interconnection Operations Services (IOS) building blocks.

Regulation and load following (Figure 2) encompass the intra-hour generation adjustments necessary to balance the control area. The distinction between the two services involves both the nature of the demand deviations and the time frame over which they occur. Regulation generally refers to the actions required to compensate for fast – e.g. minute-by-minute or faster – fluctuations in demand. These are of a random nature, requiring both up and down adjustments of supply.

Load following consists of the longer trends in demand changes, which are somewhat predictable and for load usually have a defined direction depending on the period in the day. Adjustments for following load are done over longer periods (five or ten minutes), and are usually performed in an economic manner by dispatch of new base points to generators.

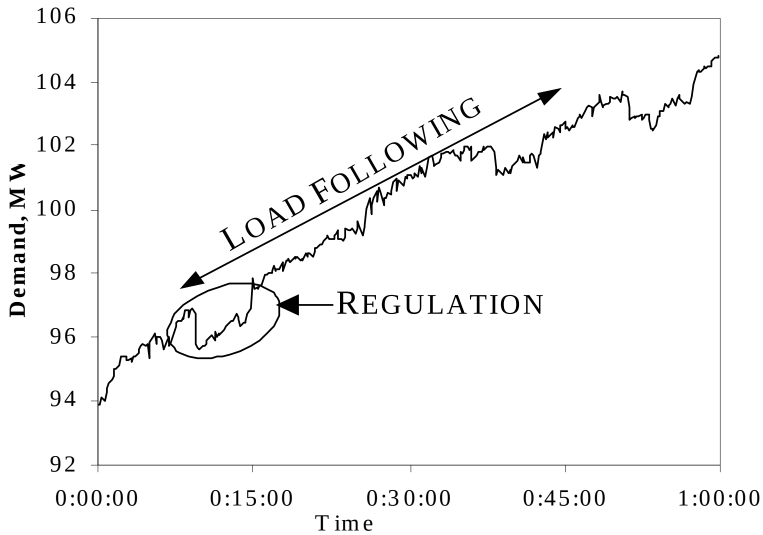


Figure 2: Illustration of regulation and load following from NREC IOS Reference Document

Regulation

This component of reserves includes the capacity on AGC that is controlled to compensate for fastest fluctuations in the control area demand. The analytical approach defines this as an energy-neutral service over even a very short term; it is simply a capacity range over which one must move to compensate for random variations in control area load.

The amount of this service required by the control area is determined by extracting a "regulating characteristic" from high-resolution load data. This is accomplished by subtracting the actual load from an underlying trend, usually constructed from a rolling average window on the actual load data.

A trend value was computed with a 20 minute rolling average window. A snapshot of the trend and actual load data for one of the samples is shown in Figure 3.

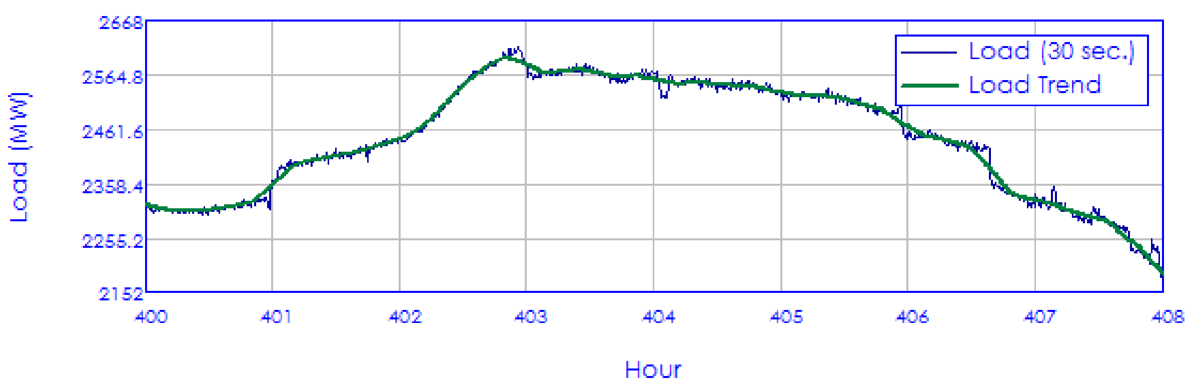


Figure 3: Extracting the regulation characteristic

The difference between the actual load and the trend, as shown in Figure 5, can be processed to determine the statistical characteristics (Figure 6). Because of the selection of the rolling average window, the average value is very near zero. In terms of regulation capacity to compensate for the random fluctuations, the standard deviation is the more useful statistic. By carrying capacity equivalent to some multiple of the standard deviation, the number of all deviations in the sample for which enough adjustment is available can be computed.

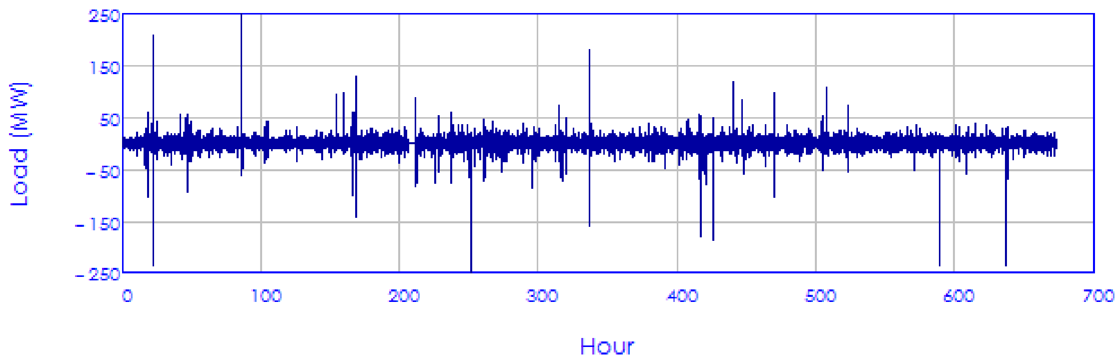


Figure 4: "Regulation characteristic" of WAPA load

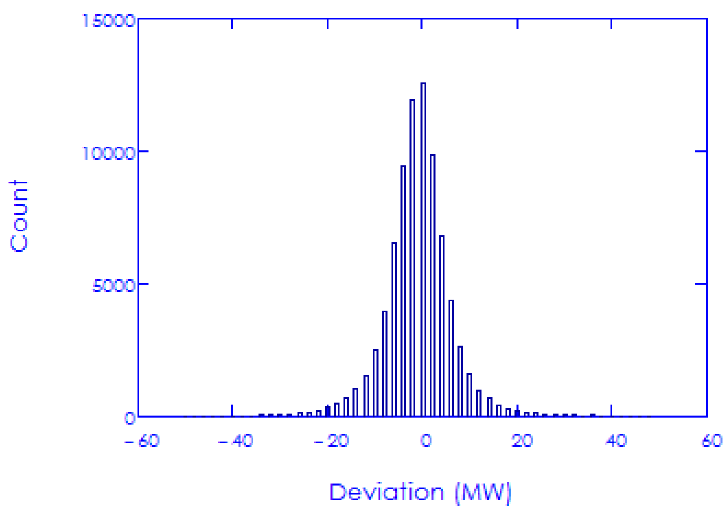


Figure 5: Distribution of WAPA load variations from 20-minute rolling average

The standard deviation of the regulation characteristic over the sample data is computed to be 9.7 MW. [Note: The "spikes" visible in the plot of Figure 4 were assumed to be measurement errors, and were removed from the data prior to the calculation of the standard deviation).

From previous studies and background information provided by Oak Ridge National Laboratory[1,] the regulation requirement for a control area is somewhere between 3 and 5 times the standard

1 B. Kirby and E. Hirst, *Customer-Specific Metrics for the Regulation and Load-Following Ancillary Services*, ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge, TN, January 2000.

deviation of the load regulation characteristic. Using the smaller multiplier, the regulation requirement for the WAPA load as described in this sample data is about 29 MW. This capacity service is often referred to as "Regulation UP / Regulation DOWN" to emphasize the bi-directional characteristic. In some markets (e.g. California ISO), it is split into two separate services.

Wind generation also exhibits variations on this time scale. Since these variations result from completely separate and independent processes (meteorology and terrain vs. individual customer actions), it is safe to conclude that the variations are not correlated with those of the load. Given this, the standard deviation of the load net wind can be computed from the following equation:

$$\sigma_{load\_net\_wind} := \sqrt{\sigma_{load}^{2} + \sigma_{wind}^{2}}$$

Using the high-resolution wind data provided by WAPA for the existing plants (130 MW installed capacity), the effect of wind generation on the control area regulation requirement can be extracted. Using the same mathematical and statistical operations on the WAPA load net of the existing wind generation, the standard deviation of the regulation characteristic increases to 9.84 MW. Some further match shows that the assumption of statistical independence between load and wind variations on this time scale, implied in the equation above, holds. The regulation characteristic for the aggregate wind generation has a standard deviation of 1.74 MW. Plugging this number into the equation along with the load standard deviation, the result from the analysis of the combined wind and load is confirmed:

$$\sqrt{9.70^{2} + 1.74^{2}} = 9.85$$

In terms of regulation capacity needed to maintain the same control performance as for load alone, the incremental amount required for the existing wind generation would be less than 1 MW (3 times (9.85-9.7)).

Because the resolution of the synthesized wind data is too low for the preceding analysis, the regulation characteristic of the wind from the base and tribal penetration scenarios must be estimated. It will be assumed that the plants in the scenario exhibit variations on the time scale of interest similar to the existing plants; i.e., the regulation characteristic for 130 MW of wind generation has a standard deviation of 1.74 MW. This number is relatively consistent with what has been observed from other measurements.

For the base scenario:

$$\sigma_{base} := \sqrt{9.7^{2} + \frac{723}{130} \cdot 1.74^{2}} = 10.5$$

$$3 \cdot \sigma_{base} = 31.6$$

$$3 \cdot \sigma_{base} - 3 \cdot \sigma_{load} = 2.5$$

For the tribal scenario:

$$\sigma_{tribal} := \sqrt{9.7^2 + \frac{753}{130} \cdot 1.74^2} = 10.6$$

$$3 \cdot \sigma_{tribal} = 31.7$$

$$3 \cdot \sigma_{tribal} - 3 \cdot \sigma_{load} = 2.6$$

The conclusion here, as in other studies, is that the fast regulation capacity necessary for the control area is not appreciably influenced by amounts of wind generation in the range of the penetration levels considered here.

Load Following

So, getting back to the hourly simulation and analysis, for a given hourly load in the data set for the study, there are periods during that hour where the demand is higher and lower than the average. Generation must be adjusted to meet these values within the hour. Figure 7 illustrates this with actual data.

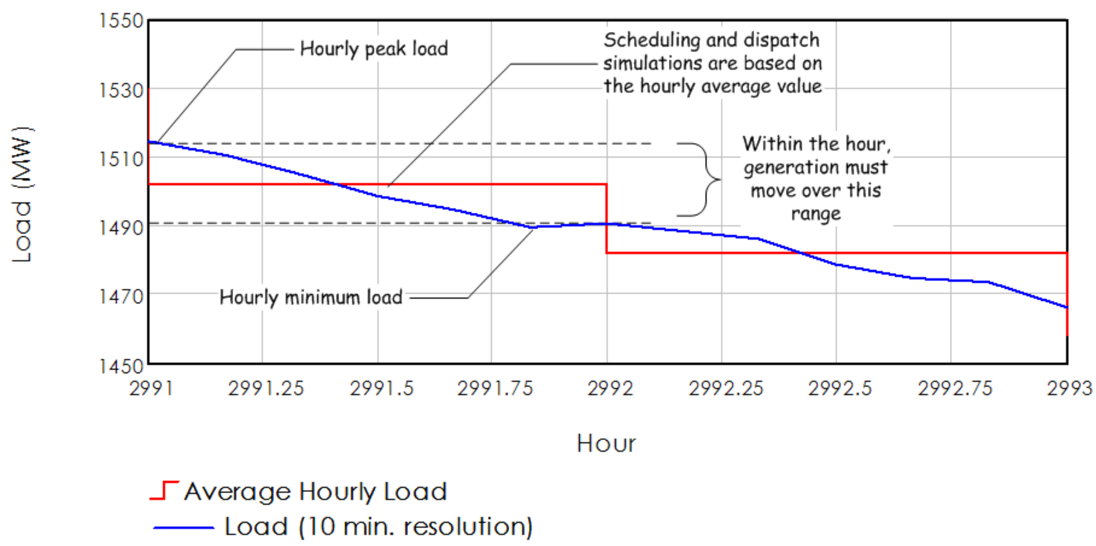


Figure 6: Hourly average and ten-minute load – WAPA load data

The previous approach can be refined slightly to recognize the fact that generation that is scheduled flat for the hour is likely ramped to a new base point over the top of each hour. The new "schedule" with this modification – neglecting any deviation due to short-term forecast error – is as shown in Figure 8.

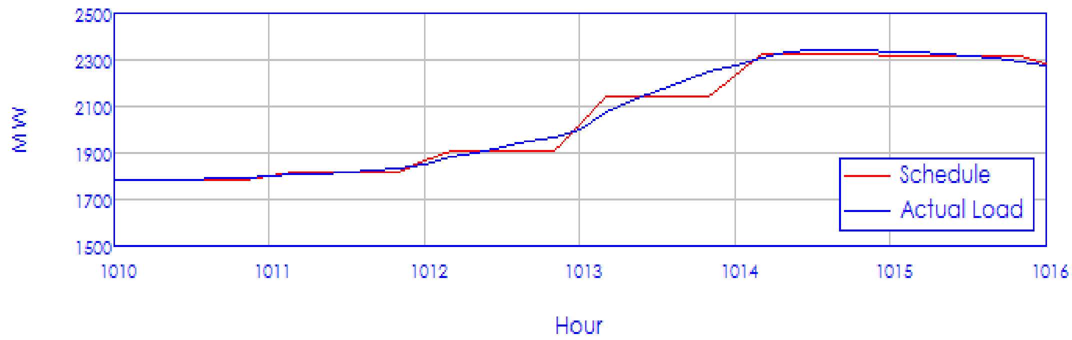


Figure 7: Hourly schedule with top-of-the-hour "ramp".

The purpose of this section is to describe a procedure for estimating the additional flexibility within the hour that would be required to manage a control area with significant wind generation. The analysis and experimentation are based on an annual record of load and wind generation at ten-minute intervals. The goal is to develop a "rule" for the amount of flexibility that would be required using information that would be available in the control room. The extended data records also provide a way to "test" the proposed rules.

The initial procedure for determining the required flexibility for load alone is as follows:

1. Using the ten-minute data, calculate the difference between the hourly schedule and the actual ten-minute load or load net of wind values. This difference is the "load following" requirement.
2. Devise a rule that will allocate an amount of in-hour flexibility necessary to meet or exceed the hourly load following requirement. This amount will change hourly.
3. Count the number of ten-minute intervals over which the load following requirement exceeds the allocated amount by an amount greater than the L10 of the control area (54.47 MW for WAPA UGPR, per NERC 2006 documentation). If it does, this period is considered a "violation".
4. Tabulate the number of violations over the 52,000+ intervals in the annual sample. Adjust the rule for allocating flexible generation to reach the desired score.

Figure 9 illustrates the procedure above using archived data from WAPA.

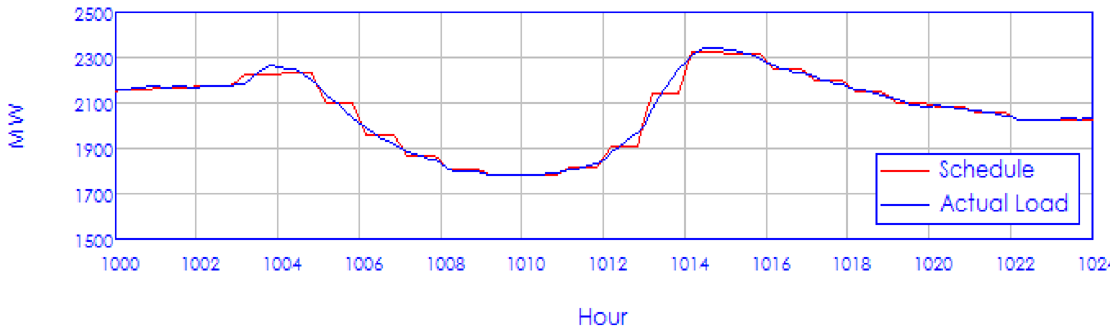


Figure 8: "Flat" hourly schedules as the basis for computing load following requirements

With flat generation schedules equal to the hourly average value of load net of wind generation, additional load following reserves would be required to meet the performance levels described above. While the value would vary hourly depending on the level of wind production, the hourly average values for the additional operating reserves are as shown in Table 1. These values assume that control performance, as measured by the approximate CPS2 metric used in these calculations, remains as for load alone. It should be noted that current WAPA practice results in very high CPS2 performance relative to other control areas in the country. If the metric were relaxed, the load following reserve requirements for wind generation would decrease, with WAPA UGPR remaining comfortably in compliance with the requirements for control.

The mathematical and statistical analysis from which these load following reserves were estimated is detailed in Appendix A.

Table 1: Estimated Load Following Requirements for WAPA Load and Wind Scenarios - Perfect Short-Term (Hour-ahead) Forecasting

Scenario	Load Following Requirement		
	Average	Maximum	Std. Deviation
Load Only	0.0 MW	0.0 MW	0.0 MW
Existing Wind	18.5 MW	36.0 MW	9.7 MW
Base Scenario Wind	28.0 MW	40.0 MW	10.3 MW
Tribal Scenario Wind	29.4 MW	42.4 MW	11.0 MW

Impacts of Short-Term Forecast Error on Real-Time Operations

The previous analysis assumes that the reserves for the hour are planned on the basis of perfect knowledge of the next hour average load and wind generation. This is the situation with the minimum uncertainty, and relates mostly to the real-time operation of the system to compensate for inside-the-hour variations from some constant average value. In reality, there are operational decisions made prior to this hour that will affect the generation flexibility that is needed to manage the control area.

Schedule deviations are a consequence of the net of short-term load and wind generation forecast errors. Some control areas augment their hourly reserves to insure that enough controllable capacity is allocated to cover the shortfall or be turned down if there is surplus. The schedule deviation will be larger with wind generation. An approach similar to that used to calculate incremental regulation and load following reserves can be employed to determine how much additional capacity must be allocated to cover incremental forecast error. For this example, the statistical variability of the synthesized wind generation for each scenario is determined and used as a guide for allocating additional reserves to cover short-term forecasts (e.g., one hour before the operating hour). This approach assumes a "persistence" forecast for wind generation, where the forecast for the next hour is simply what was delivered in the current hour.

Load forecast errors also contribute to the schedule deviations. For this illustration, however, it is assumed that load is forecast perfectly one hour in advance. Assuming an imperfect forecast would slightly reduce the reserves carried to cover wind generation forecast error alone, since the errors in load and wind forecast would likely not be highly correlated, for most hours.

The metrics of the hourly load following requirements considering short-term wind generation forecast error are shown in Table 2. The impact of short-term wind generation forecast errors is fairly significant, especially for the larger penetration scenarios.

Table 2: Estimated Load Following Requirements for WAPA Load and Wind Scenarios (98% CPS2 metric)

Scenario	Load Following Requirement w/ Forecast Error		
	Average	Maximum	Std. Deviation
Load Only	0.0 MW	0.0 MW	0.0 MW
Existing Wind	18.5 MW	36.0 MW	9.7 MW
Base Scenario Wind	73.5 MW	105.0 MW	27.0 MW
Tribal Scenario Wind	77.2 MW	111.3 MW	28.9 MW

Using the Hourly Reserve Profile in Production Simulations

The profiles described by their statistics in Table 1 and Table 2 are actually forecasts of load following reserves for each hour. Their impacts are assessed indirectly in the hourly production simulations. However, before applying these profiles, and important adjustment must be made.

In the production simulations, the economic dispatch step is a proxy for the real-time operation of the WAPA system. Some portion of the reserve allocated for each hour was in consideration of short-term forecast error. Therefore, if the scheduled load net of wind generation is actually higher in the operating hour than forecast the previous hour, reserves can be used to cover some or all of the difference.

As an example, assume that for a given hour, 100 MW of load following reserve was allocated, and that 45 MW of that amount were due to expected deviations from the hourly schedule. Wind generation at the time of the forecast was 250 MW. In the given hour, the average wind generation dropped to 210 MW. To reflect the fact that reserves are used to cover the drop in wind generation, the load following reserve constraint for the hour would be reduced from 100

MW to 60 MW; i.e., the 40 MW drop in wind generation from a persistence forecast of 250 MW can be covered with reserves.

Therefore, in preparation for the hourly production simulations, the vector of reserve constraints should be adjusted as described above. This prevents “double counting” of the reserve requirements. If the drop in wind generation is larger than the amount of reserves set aside for schedule deviation, only the amount allocated for schedule deviation can be deducted from the hourly reserve constraint.

Summary

Chronological production modeling at hourly granularity has become the de-facto standard method for assessing wind generation impacts on power system operations. The hourly time step, however, is not sufficient to capture what may be important considerations for real-time balancing and frequency support.

Methods have been developed to estimate the requirements for incremental regulating reserves necessary to manage the power system in real-time under the influence of the variable wind generation. Using high-resolution load and wind data (10 minute or smaller increments), estimates of hourly requirements of regulating reserve can first be calculated for load alone and calibrating to operating practice, then expanded to consider the effects of wind generation.

The application of these methods in this document assumes that WAPA will bear sole responsibility for managing their balancing authority, i.e. the incremental regulating burden due to wind generation connected to the WAPA system must be borne by WAPA alone. This represents the “worst case” scenario for WAPA, since it is well established that other arrangement that effectively aggregate more load and more wind generation can reduce the control burden.

As was demonstrated in the 2006 Minnesota Wind Integration Study, spreading the variability of both wind generation and load over a larger geographic footprint and a larger collection of conventional generating units and load has significant benefits operationally. If the WAPA load and wind generation were to be combined with a larger entity like MISO, it is likely that the overall variability of the combination would not increase at all. This, of course, assumes that adequate transmission is available to allow the two areas to be managed as a single operating entity.

Appendix A: Characterizing Wind Generation Variability for Estimating Incremental Reserve Requirements

The reserve estimates in the previous section were developed from statistical characterizations of wind generation variability. There are two elements to this variability. The first consists of variations from the actual hourly average at ten minute intervals. The second element is comprised of the difference in the hourly average from what was forecast the hour previous.

Using the synthesized wind generation data for the three scenarios, the differences between each ten-minute production value and the hourly average were sorted by production level. Figure 10 shows the distribution of these differences for the Tribal wind scenario when hourly average production is between 60% and 70% of nameplate.

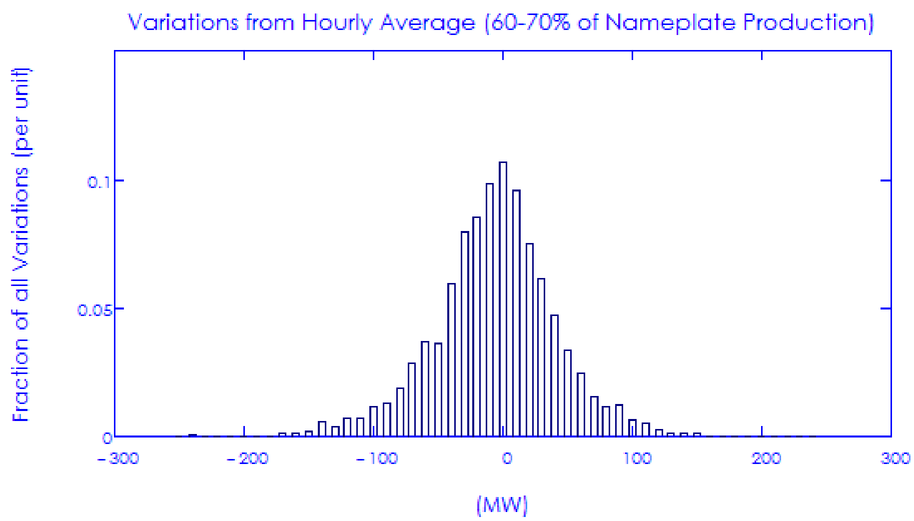


Figure 9: Variations from hourly average – Tribal Wind scenario

Assuming that the distribution is symmetrical around zero (no difference between the ten minute value and the hourly average) and Gaussian, the standard deviation of the sample can be used to estimate the expected variability. In Figure 11, the standard deviation for the deciles of production for each of the three scenarios is shown.

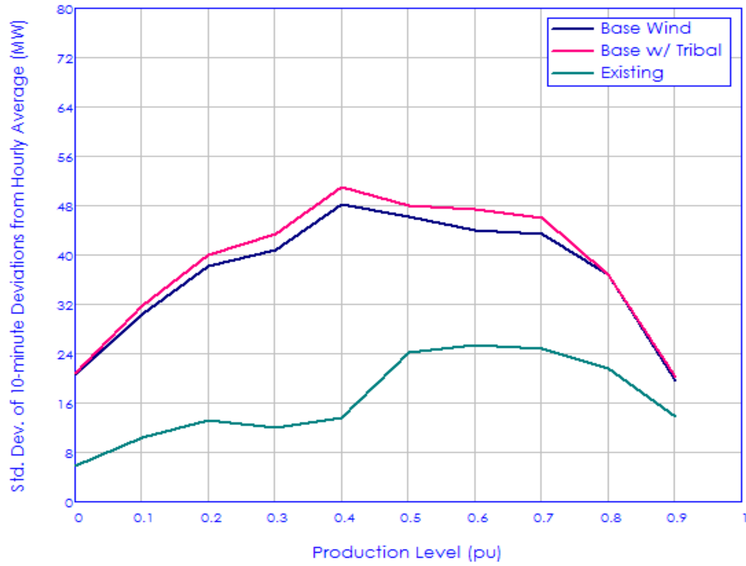


Figure 10: Standard deviation of ten-minute deviations from hourly average for three wind scenarios. Values are computed for production deciles.

The curves from the figure express the expected amount of deviation in ten-minute averaged wind production from the actual hourly average. For example, for the Base scenario, approximately 90% of the ten-minute variations from the hourly average would be within +/-96 MW (2 times the standard deviation of 48 MW) when production is 40% of rated. The expected variability is obviously much smaller at lower production levels, and interestingly, is also smaller for production levels near rated.

To more easily utilize the statistical characteristics of the variability in a "rule" that could be used in real-time operations, the curves from Figure 11 are approximated with quadratic functions. The derived functions for the curves are:

Existing Wind: $$V_E(x) := 25 - \frac{(x-70)^2}{250}$$

Base Scenario: $$V_B(x) := 50 - \frac{(x-375)^2}{4200}$$

Base Scenario + Tribal Wind: $$V_T(x) := 53 - \frac{(x-395)^2}{4400}$$

Figure 12 shows these quadratic approximations graphically.

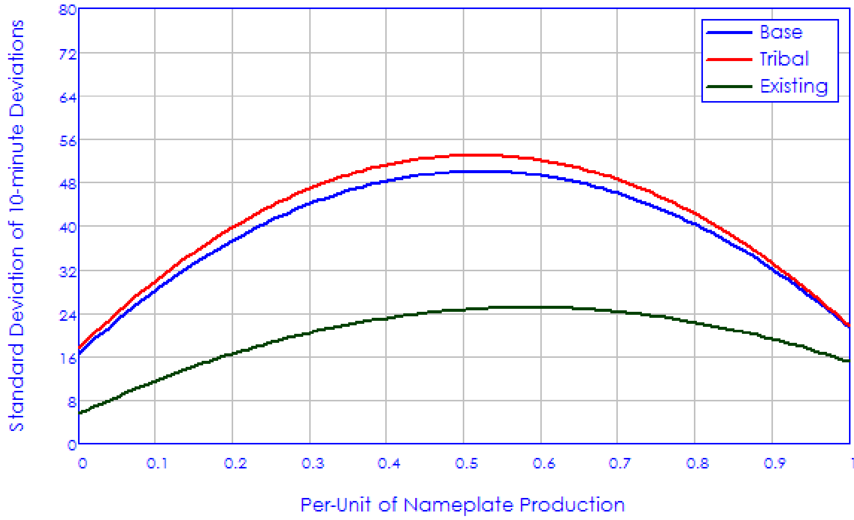


Figure 11: Approximation of curves from Figure 11with quadratic expressions; vertical axis in MW. All three wind scenarios shown.

The second element of the statistical characterization concerns changes in wind generation from hour to hour. For this exercise, it is assumed that persistence is the method employed for forecasting wind production one hour into the future. The "errors" in this forecast, then, are simply the changes from one hour to the next. Processing the scenario wind data as before, the standard deviation of errors in the one-hour persistence forecast are computed for deciles of production. The resulting characteristics, shown in Figure 13 are nearly identical to those derived for the ten minute variability. Consequently, the same quadratic equations show above can be used to account for schedule errors due to the persistence forecast for wind generation.

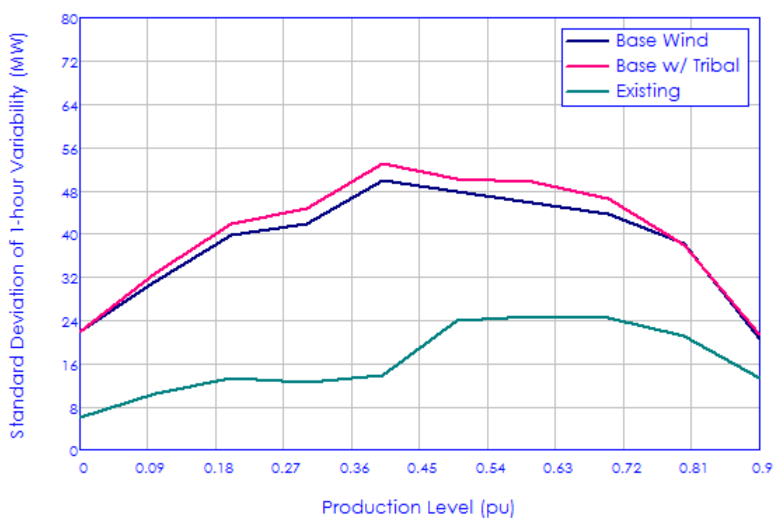


Figure 12: Standard deviation of hour-to-hour average production changes, i.e. persistence forecast "error" expectation. All three wind scenarios shown

The statistical characterizations of wind generation variability provide a basis for developing equations to calculate the required amount of regulating reserve for the control area. Regulating reserve for load alone is augmented by an amount that is a function of current wind generation. If wind production is zero, the added amount will also be zero.

To formulate this equation, an empirical approach using ten-minute load and wind generation data is used (as described earlier in the document). Because the additional regulating reserve for load alone (over and above what is required to compensate for the random fast fluctuations) was shown earlier to be zero for WAPA load, the expression for this incremental regulating reserve consists only of the quadratic expression shown above in Figure 13.

The "scheduled" hourly control area demand is calculated by assuming the one-hour ahead load forecast is perfect, and that wind generation will be the same as the previous hour. The regulating reserve requirement is then the difference between this schedule and the actual load net of wind generation. A value is computed for each ten-minute interval.

The incremental regulating reserve is assumed to be some multiple of the quadratic equation that describes the variability and persistence forecast error for the scenario. A value for the coefficient is assumed, then the number of ten-minute regulation variations over the 52,000 samples of data that exceed the regulating reserve plus the L10 for the control area are counted. The coefficient is adjusted until some high percentage (roughly equivalent to the desired CPS2 metric) is achieved.

The requirements shown in Table 2 were based on a CPS2 metric of 98%. The incremental regulating reserve equations from which the numbers were generated are:

Existing Wind: $Inc.RR = 1.5 \cdot V_E(Wind_{H-1})$

Base Scenario: $Inc.RR = 2.1 \cdot V_B(Wind_{H-1})$

Base Scenario + Tribal Wind: $Inc.RR = 2.1 \cdot V_T(Wind_{H-1})$

If the target CPS2 score were reduced to 95%, the equations for incremental regulating reserve become:

Existing Wind: $Inc.RR = 0.14 \cdot V_E(Wind_{H-1})$

Base Scenario: $Inc.RR = 1.20 \cdot V_B(Wind_{H-1})$

Base Scenario + Tribal Wind: $Inc.RR = 1.23 \cdot V_T(Wind_{H-1})$

The corresponding characteristics of the regulating reserve profile for ten-minute variations are shown in Table 3.

Table 3: Estimated Load Following Requirements for WAPA Load and Wind Scenarios – 95% CPS2

Scenario	Load Following Requirement w/ Forecast Error		
	Average	Maximum	Std. Deviation
Load Only	0.0 MW	0.0 MW	0.0 MW
Existing Wind	18.5 MW	36.0 MW	9.7 MW
Base Scenario Wind	42.0 MW	60.0 MW	15.4 MW
Tribal Scenario Wind	45.2 MW	65.2 MW	16.9 MW

Glossary

(Source: NERC Reference Document: Interconnection Operations Services; Version 1.1, March 21, 2002)

The definitions of IOS described in this IOS Reference Document are as follows:

> **REGULATION.** The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that responds to automatic controls issued by the BALANCING AUTHORITY.
>
> **LOAD FOLLOWING.** The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that is dispatched within a scheduling period by the BALANCING AUTHORITY.
>
> **CONTINGENCY RESERVE.** The provision of capacity deployed by the BALANCING AUTHORITY to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Council contingency requirements. CONTINGENCY RESERVES are composed of CONTINGENCY RESERVE–SPINNING and CONTINGENCY RESERVE–SUPPLEMENTAL.
>
> **REACTIVE POWER SUPPLY FROM GENERATION SOURCES.** The provision of reactive capacity, reactive energy, and responsiveness from IOS RESOURCES, available to control voltages and support operation of the BULK ELECTRIC SYSTEM.
>
> **FREQUENCY RESPONSE.** The provision of capacity from IOS RESOURCES that deploys automatically to stabilize frequency following a significant and sustained frequency deviation on the INTERCONNECTION.
>
> **SYSTEM BLACK START CAPABILITY.** The provision of generating equipment that, following a system blackout, is able to: 1) start without an outside electrical supply; and 2) energize a defined portion of the transmission system. SYSTEM BLACK START CAPABILITY serves to provide an initial startup supply source for other system capacity as one part of a broader restoration process to re-energize the transmission system.
>
> The six IOS above are a core set of IOS, but are not necessarily an exhaustive list of IOS. Other BULK ELECTRIC SYSTEM reliability services provided by generators or loads could potentially be defined as IOS.

The following related terms are used in this IOS Reference Document:

> **BALANCING AREA.** An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation (and controllable loads) directly to maintain its interchange schedule with other BALANCING AREAS and contributes to frequency regulation of the INTERCONNECTION.
>
> **BALANCING AUTHORITY.** An entity that: integrates resource plans ahead of time, and maintains load-interchange-generation balance within its metered boundary and supports system frequency in real time.
>
> **BULK ELECTRIC SYSTEM.** The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission facilities are interconnected.

CONTINGENCY RESERVE – SPINNING. The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation synchronized to the system and fully available to serve load within T_{DCS} minutes of the contingency event; or
- Load fully removable from the system within T_{DCS} minutes of the contingency event.

CONTINGENCY RESERVE – SUPPLEMENTAL. The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within T_{DCS} minutes of the contingency event; or
- Load fully removable from the system within T_{DCS} minutes of the contingency event.

DEPLOY. To authorize the present and future status and loading of resources. Variations of the word used in this IOS Reference Document include DEPLOYMENT and DEPLOYED.

DYNAMIC TRANSFER. The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BALANCING AREA into another.

INTERCONNECTED OPERATIONS SERVICE (IOS). A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected BULK ELECTRIC SYSTEMS.

INTERCONNECTION. Any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.

IOS SUPPLIER. An entity that offers to provide, or provides, one or more IOS.

IOS RESOURCE. The physical element(s) of the electric system, which is (are) capable of providing an IOS. Examples of an IOS RESOURCE may include one or more generating units, or a portion thereof, and controllable loads.

LOAD-SERVING ENTITY. An entity that: Secures energy and transmission (and related generation services) to serve the end user.

MANEUVERABILITY. The ability of an IOS RESOURCE to change its real- or reactive-power output over time. MANEUVERABILITY is characterized by the ramp rate (e.g., MW/minute) of the IOS RESOURCE and, for REGULATION, its acceleration rate (e.g., $MW/minute^2$).

OPERATING AUTHORITY[2]. An entity that:

[2] Examples of OPERATING AUTHORITIES, as used in the IOS Reference Document, include the following authorities defined in the NERC Functional Model: RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR, TRANSMISSION SERVICE PROVIDER, and INTERCHANGE AUTHORITY. The IOS Reference Document uses the term OPERATING AUTHORITY when the reference generally applies to more than one functional authority. A specific functional authority is identified when the reference applies only to that authority.

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission security, and/or emergency preparedness; and
2. Is accountable to NERC and one or more Regional Reliability Councils for complying with NERC and Regional Policies; and
3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING RESERVE. That capability above firm system demand required to provide REGULATION, load forecasting error, equipment forced and scheduled outages, and other capacity requirements.

Appendix F

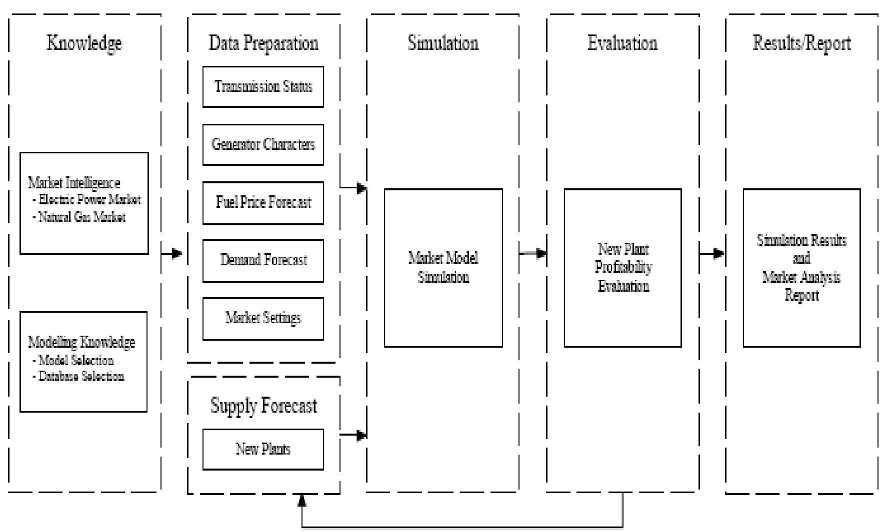
Transmission Planning Documents

Please be advised that Appendix F: Transmission Planning Documents may contain information that is for the exclusive use of the named recipient(s). No personnel whose primary job function is in a Power Merchant organization may view or have access to such information as required by FERC Standards and Codes of Conduct, Critical Energy Infrastructure Information (CEII) and/or state Codes of Conduct. In addition, persons authorized to receive this information shall take precautions not to disclose or be conduits of any non-public transmission information to any party's marketing and Sales or Energy Affiliate personnel. If you have received this appendix in error, please notify the sender immediately, and destroy this appendix and any attachments.

Appendix G

Ventyx-Overview of Market Simulation Assumptions

To assist in evaluating impacts of adding tribal wind energy to the Western Balancing Area, Ventyx was retained to complete a series of power market simulations. In preparing these simulations, Ventyx used its PROMOD IV simulation model to develop two distinct sets of power market simulations for evaluating tribal wind in the Western Balancing Area. Figure G-1 provides an overview of the process that Ventyx used in developing market simulations. As shown in Figure G-1, market simulations rely upon fundamental input data characterizing all electricity generating units in the market, electricity demand forecasts, and the transmission system configuration. Fuel and emissions price forecasts are reflected for each submarket. New entry power supply is evaluated against both financial profitability and sub-market reliability constraints.



Overview of Market Simulation Process
Figure G-1

In evaluating the impact of adding a Tribal Wind Demonstration Project to the Western Balancing Area, two separate sets of market simulations were developed.

Evaluation of Long-Term Economics of Identified Wind Projects

- *30-Year Simulation of Upper Midwest power markets*
- *Zonal transmission modeling*
- *Comparison of Western purchased power costs with and without identified wind projects*
- *Hydro-electric energy scenario modeling to evaluate economic impacts over a range of conditions*

Evaluation of Operational Feasibility of Identified Wind Projects in Western Balancing Area

- *2011 Nodal Simulation*
- *Detailed transmission modeling*
- *Evaluation of how additional injections of wind energy into the UGPR affects overall system operations and transmission constraints*

The two sets of market simulations use the same basic datasets, with the primary difference being the level of detail used in modeling the transmission system operations. In the zonal analysis, transmission limits and constraints are defined over a set of transmission paths, rather than reflecting the operational detail of each line. Transmission path ratings are enforced as constraints on the ability to move economic energy between market zones, but transmission constraints inside of each zone are not modeled. In contrast, in the nodal analysis, individual transmission lines are modeled at a detailed level, in addition to contingency events and interface constraints. These distinctions are outlined as follows:

Transmission System Differences between Zonal and Nodal Cases

- Summer and Winter Transfer Limits with Tariffs and Losses for zonal transmission
- Full Transmission Powerflow for PROMOD IV TAM
  - Seasonal Line Ratings
  - Load Distribution by Bus
  - Critical Contingency Events based on published books of flowgates, as well as Day-Ahead and Real-Time Events
  - Generator Bus Mappings
  - Trading Hub Definitions

In developing the market simulations, Ventyx relied upon its standard set of input assumptions for most of the data, with customization for data describing Western's hydro-electric energy production levels and patterns, and for data describing wind resources in the Western Balancing Area, including tribal wind resources. Ventyx's standard set of input assumptions relied upon the Platt's Base Case as a primary data source. These data are supplemented and enhanced by using additional data from the regional reliability councils, independent system operators, company research, publications, and Ventyx's own experience and expertise. These primary data underlying the study rely upon the same base case assumptions that Ventyx uses in other market simulation consulting projects. A listing of public data sources that are relied upon in developing Ventyx's market simulation data include:

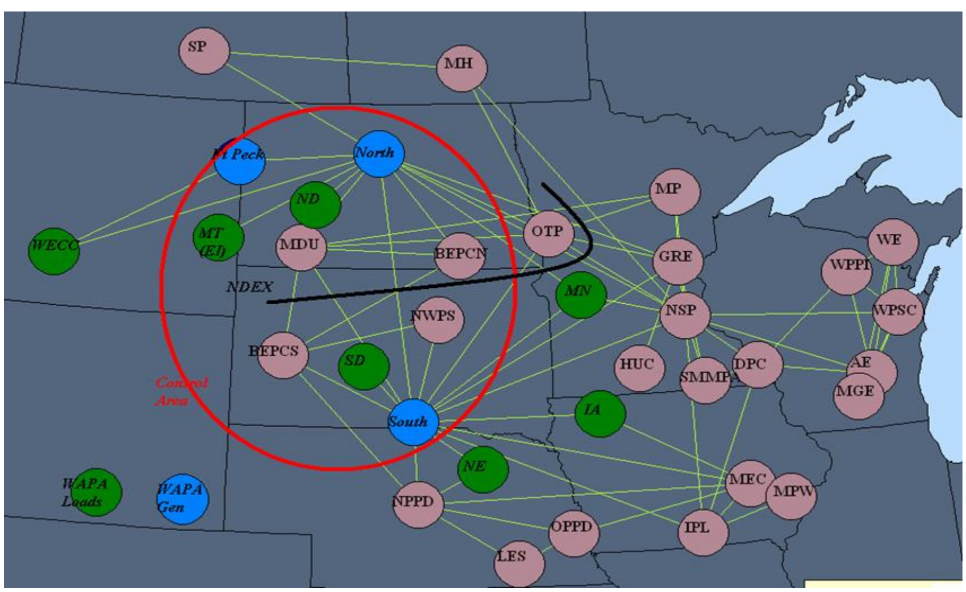
- ***Public Data Sources Relied Upon in Developing Ventyx's Simulation Data***
  - Platt's Energy Advantage
  - Ventyx EnergyVelocity
  - NERC, Energy Company and ISO websites
  - North American Electric Reliability Council (NERC) Electric Supply and Demand (ES&D) reports
  - Trade Publications such as Generation Quarterly, MW Daily, Enerfax, and Gas Daily
  - FERC forms including Forms 1, 714 and 715
  - Energy Information Agency (EIA) Forms (860, 867, 411, 412)
  - Bi-weekly Report of New Construction
  - Rural Utility Service (RUS) Form 12
  - Generating Availability Data Systems (GADS) Data

- ***Ventyx expertise & company research provides additional information***

For the nodal analysis using PROMOD IV Transmission Analysis Module, the Eastern Interconnect Multiregional Modeling Working Group transmission load flow datasets were used to specify the detailed transmission system.

The Ventyx base case data have been supplemented/enhanced with analysis of Western historical data and hydro-electric data available from the Army Corps of Engineering, as discussed earlier in this report.

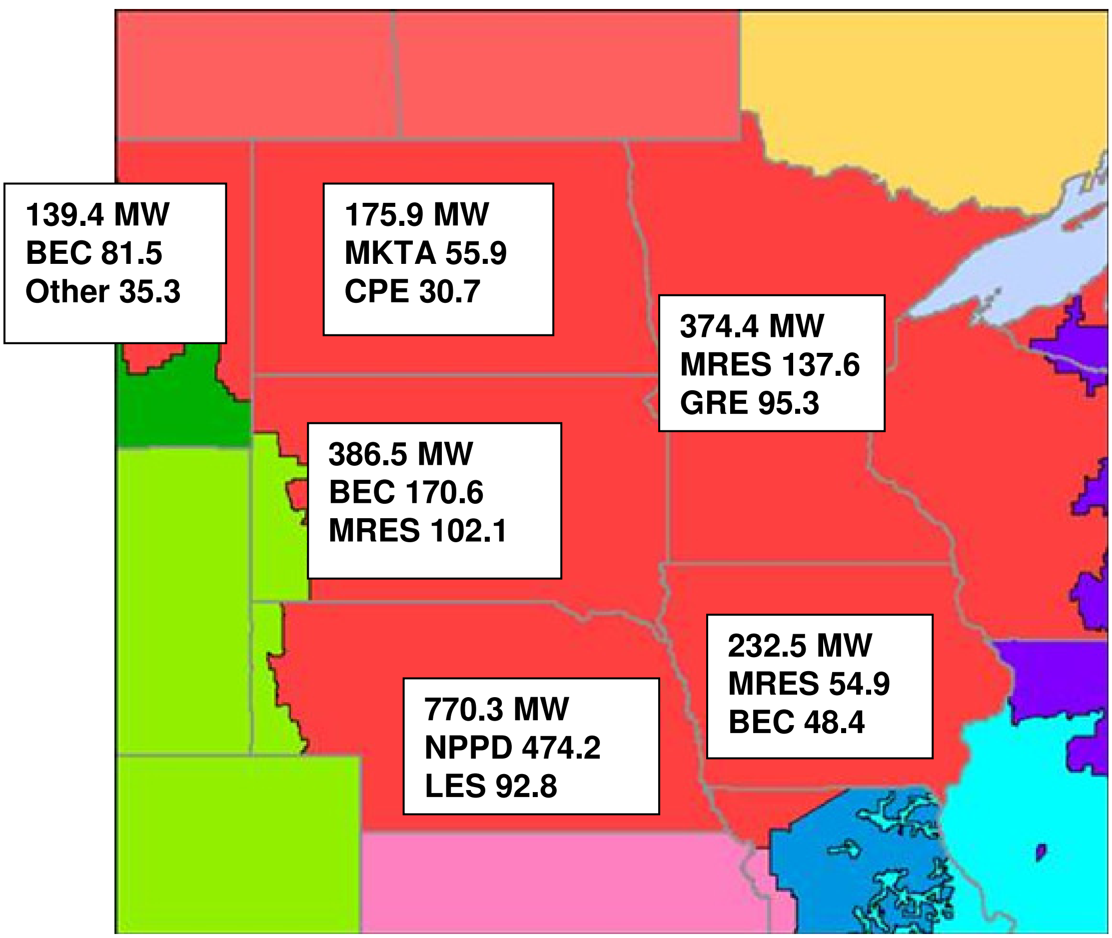
The market footprint used in this study focuses primarily on the upper Midwest, and is illustrated below in Figure G-2:



Market Topology
Figure G-2

In the zonal market simulation, generators and loads are dispatched first within each of the zones illustrated in Figure G-2, and then economic transfers are scheduled between zones using the transmission paths. In a zonal simulation, path transfer ratings limit how much energy can get scheduled along each path. In contrast, in the nodal market simulation, the transmission system is modeled in more detail so that individual line electrical characteristics are reflected, and ratings along transmission interface paths can vary dynamically depending upon generation, load and transmission flow conditions. In the nodal simulation a much bigger footprint than shown in Figure G-2, encompassing most of the Eastern Interconnect, was used.

Of the market zones depicted in Figure G-2, the Western's Balancing Area is outlined by the red circle. Within Western's Balancing Area, Ventyx made the load allocations illustrated in Figure G-3 in reflecting Western's contractual load obligations. As shown, the largest allocations of load occur in Nebraska, South Dakota, Minnesota and Iowa, followed by North Dakota and Montana. These load allocations are consistent with historical Western obligations. They do affect the geographic distribution of power purchases in the Western's Balancing Area, and also the transfer and delivery of energy from wind resources, from both tribal and non-tribal sources.



Western Load Allocations by State with Top Users
Figure G-3

Given the relatively high quality wind regimes in the upper Midwest and upper Great Plains region, the level and timing of renewable energy additions plays an important role in developing power market simulations in that region. In developing likely wind generation for this study, we included target levels of new capacity consistent with individual state Renewable Portfolio Standards (RPS). In the upper Midwest, the following state RPS requirements were implemented:

Table G-1 – Surrounding State Renewable Portfolio Standards

State	RPS Requirement (% Load)	Implementation Year
Minnesota	25%	2025
Wisconsin	10%	2015
Iowa	105 MW	
Illinois	25%	2025

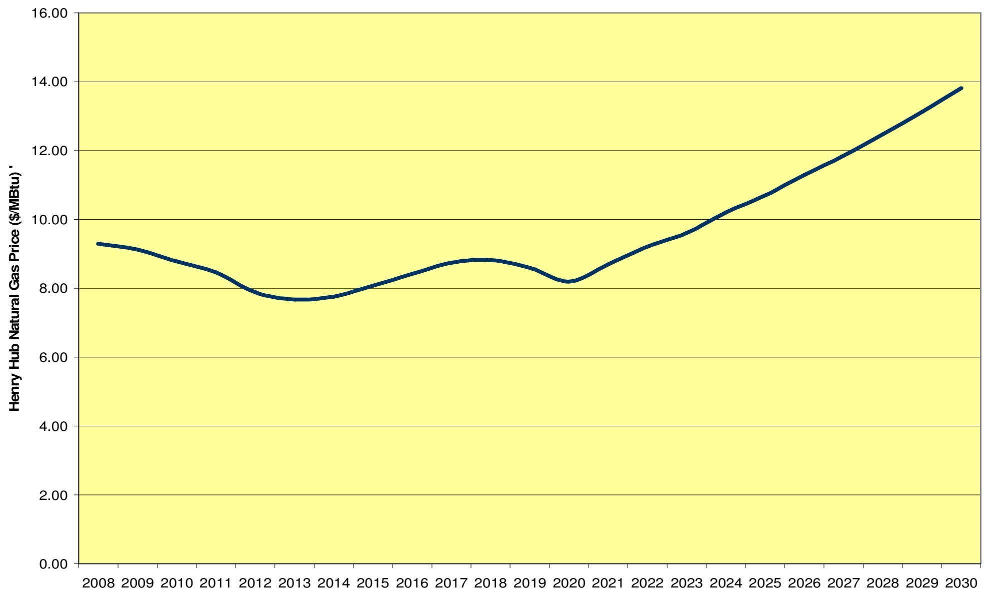
Table G-2 lists the new "generic" wind resources included in the study in the broader geographic region. In addition to those quantities, proposed non-tribal wind resources in the Western's Balancing Area were also included in the study.

Table G-2 – Generic Wind Generation Additions

Generic Wind Additions within WHFS Footprint

	2010 to 2015	2016 to 2020	2021 to 2025	2026 to 2030	2031 to 2035	2036 to 2040	Grand Total
Carolinas		1200	1200	300	300	300	3300
Dakotas			300	200	200	200	900
Illinois	5300	6600	2400	1800	1700	1700	19500
Indiana		300					300
Iowa		200					200
Manitoba	400	200					600
Minnesota	1600	2400	1800	1600	1600	1600	10600
Missouri	1400	1200	1600	1000	500	500	6200
PJM East	2200	2600	1600	300	300	300	7300
PJM South			100				100
SPP North	300	700	200	100	100	100	1500
Western PJM	6000	3100	1700	600	300	300	12000
Wisconsin	600	500	300	200	200	200	2000
Total	17800	19000	11200	6100	5200	5200	64500
Total MAPP	2000	2600	1800	1600	1600	1600	11200

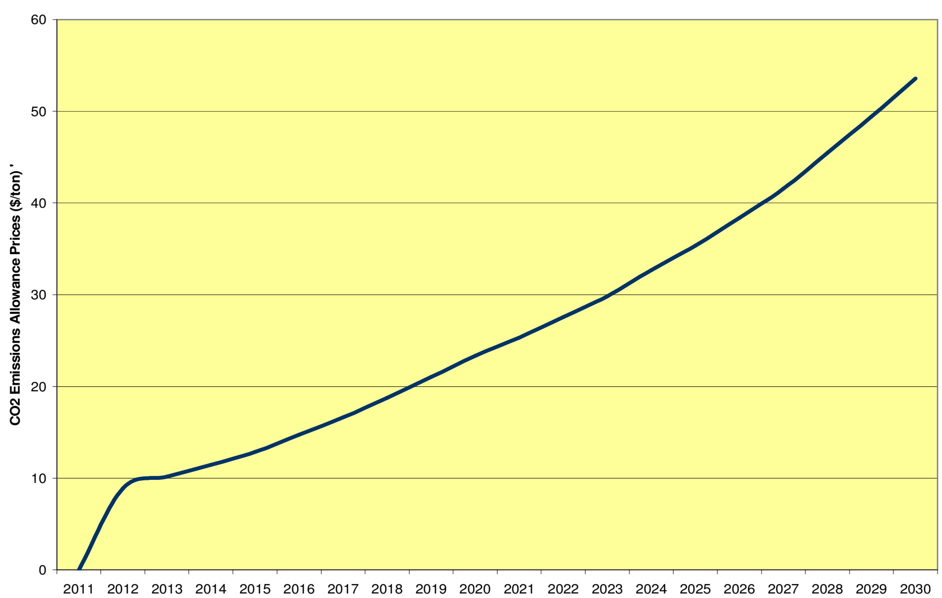
In developing the market simulations, the forecast price of natural gas is a key input assumption. Natural gas-fueled generators tend to set market clearing electricity prices during on-peak periods in the upper Midwest. Figure G-4 illustrates the natural gas price forecast at Henry Hub. Basis differentials were applied to that Henry Hub forecast to derive projected natural gas prices throughout the region.



Forecast of Annual Natural Gas Prices at Henry Hub

Figure G-4

The base case forecasts in this study also assume that a form of greenhouse gas emissions reduction policies will be enacted within the study timeframe. In developing the assumptions underlying those policies, a series of studies were examined that look at projected prices for tradeable CO2 emissions allowances. A composite view on projected CO2 prices was developed for this study, which is illustrated in Figure G-5.



Forecast CO2 Emissions Allowance Prices

Figure G-5

PROMOD IV Zonal

The long term economics of replacing Western's current purchased power are driven mainly by the market price of energy given that Western buys a majority of its supplemental energy from the spot market and has no long term contracts in place for that energy. To assist in evaluating the long-term economics of adding 50 MW of tribal wind projects to the Western Balancing Area, a 30-year zonal analysis of the MAPP energy prices was developed using PROMOD IV.

Under that approach, transmission constraints are reflected between zones, but detailed transmission operations are not modeled. Instead, market areas are specified on a zonal basis, with loads and generation modeled within each zone. Economic transfers are scheduled between zones on an hourly basis, taking into account transmission path rating transfer limits. This analytic approach provides a good long-term measure of projected electricity prices, and enables assessment of the long-term economic impact of adding tribal wind to the Western's Balancing Area.

In preparing the zonal market simulations, 9 separate cases were developed:

- **Reference Wind and Base Case Hydro** – this case only includes 158 MW of wind currently in the Balancing Area and does not include the 50 MW tribal wind project(s) or other planned wind, and assumes base case hydro-electric production levels in the Western's Balancing Area. The case serves as a reference to current conditions to be used in evaluating the effects of all the proposed wind additions.
- **Base Case Wind and Base Case Hydro** – this case does not include the 50 MW tribal wind project(s), and assumes base case hydro-electric production levels in the Western's Balancing Area. The case serves as a benchmark to be used in evaluating the long-term economics of adding tribal wind to the Western's Balancing Area.
- **Base Case Wind and Low Hydro -** this case does not include the 50 MW tribal wind project(s), and assumes low case hydro-electric production levels in the Western's Balancing Area. This case serves as benchmark for evaluating tribal wind economics under low hydro-electric production conditions, when Western is likely to face relatively higher energy procurement costs
- **Base Case Wind and High Hydro** - this case does not include the 50 MW tribal wind project(s), and assumes high case hydro-electric production levels in the Western's Balancing Area. This case serves as benchmark for evaluating tribal wind economics under high hydro-electric production conditions, when Western is likely to face relatively lower energy procurement costs
- **Tribal Wind and Base Case Hydro** - this case does include the 50 MW tribal wind project(s), and assumes base case hydro-electric production levels in the Western's Balancing Area. The case provides a base case measure of the economic value to the Western's Balancing Area of adding tribal wind to the Western's Balancing Area.
- **Tribal Wind and Low Hydro** - this case does include the 50 MW tribal wind project(s), and assumes low case hydro-electric production levels in the Western's Balancing Area.

The case provides a measure of tribal wind economics under low hydro-electric production conditions, when Western is likely to face relatively higher energy procurement costs.

- **Tribal Wind and High Hydro** - this case does include the 50 MW tribal wind project(s), and assumes high case hydro-electric production levels in the Western's Balancing Area. The case provides a measure of tribal wind economics under high hydro-electric production conditions, when Western is likely to face relatively lower energy procurement costs.
- **Base Case Wind and Base Case Hydro with No CO2 penalty** – this case does not include the 50 MW tribal wind project(s), and assumes base case hydro-electric production levels in the Western's Balancing Area. The case assumes there will be no CO2 tax or cap and trade constraint in order to evaluate the effects of that penalty on Westerns economics within the scope of this study.
- **Tribal Case Wind and Base Case Hydro with no CO2 penalty** – this case does include the 50 MW tribal wind project(s), and assumes base case hydro-electric production levels in the Western's Balancing Area. The case assumes there will be no CO2 tax or cap and trade constraint in order to evaluate the effects of that penalty on Westerns economics within the scope of this study with the addition of the 50 MW of tribal wind.

PROMOD IV Nodal

In addition to assessing the long-term economic impacts of adding tribal wind to the Western's Balancing Area, it is also important to examine short-term operation impacts of the potential new wind injections. For that purpose, we prepared a detailed PROMOD IV nodal simulation for the single year 2011. The primary purpose of the nodal simulation is to evaluate how injection of additional wind energy into the Western's Balancing Area affects overall system operations and transmission constraints. For the nodal simulations, Western hydro-electric energy projections were modeled using hourly profiles.

Under this approach, detailed transmission lines are modeled using the PROMOD IV Transmission Analysis Module (TAM). In a nodal simulation, individual transmission lines are modeled both within and across zonal markets. The electrical characteristics of the individual transmission lines are reflected in the simulation, in addition to expected contingencies, flowgate limits, and other characteristics that impact transmission system loadings and operations. Locational modeling of tribal wind projects was completed to identify any potential transmission bottlenecks for wind energy delivery, and to measure if there are any likely curtailment hours when tribal wind energy might not be deliverable due to transmission constraints.

In preparing the nodal market simulations, 7 separate cases were also developed. These cases follow the same general definitions and use the same basic input assumptions as used in developing the zonal market simulations described above, except that the nodal cases all include the more detailed transmission system modeling. In addition, the nodal cases were developed only for the year 2011.

- **Reference Wind and Base Case Hydro** – this case only includes 158 MW of wind currently in the Balancing Area and does not include the 50 MW tribal wind project(s) or other planned wind, and assumes base case hydro-electric production levels in the Western's Balancing Area. The case serves as a reference to current conditions to be used in evaluating the effects of all the proposed wind additions.
- **Base Case Wind and Base Case Hydro** – this case does not include the 50 MW tribal wind project(s), and assumes base case hydro-electric production levels in the Western's Balancing Area. The case serves as a benchmark to be used in assessing operational issues and transmission constraints on the Western's Balancing Area.
- **Base Case Wind and Low Hydro -** this case does not include the 50 MW tribal wind project(s), and assumes low case hydro-electric production levels in the Western Balancing Area. This case serves as benchmark for evaluating transmission system operations and constraints under low hydro-electric production conditions, when Western is likely to face relatively higher energy procurement costs and where expected transmission flows are impacted by lower than normal hydro-electric energy dispatch.
- **Base Case Wind and High Hydro** - this case does not include the 50 MW tribal wind project(s), and assumes high case hydro-electric production levels in the Western's Balancing Area. This case serves as benchmark for evaluating transmission system operations and constraints under high hydro-electric production conditions, when Western is likely to face relatively lower energy procurement costs and where expected transmission flows are impacted by higher than normal hydro-electric energy dispatch
- **Tribal Wind and Base Case Hydro** - this case does include the 50 MW tribal wind project(s), and assumes base case hydro-electric production levels in the Western's Balancing Area. The case provides a base case measure of operational and transmission system impacts of adding tribal wind to the Western's Balancing Area.
- **Tribal Wind and Low Hydro** - this case does include the 50 MW tribal wind project(s), and assumes low case hydro-electric production levels in the Western's Balancing Area. This case provides a measure of transmission system operations and constraints under low hydro-electric production conditions, when Western is likely to face relatively higher energy procurement costs and where expected transmission flows are impacted by lower than normal hydro-electric energy dispatch.
- **Tribal Wind and High Hydro** - this case does include the 50 MW tribal wind project(s), and assumes high case hydro-electric production levels in the Western's Balancing Area. This case provides a measure of transmission system operations and constraints under high hydro-electric production conditions, when Western is likely to face relatively higher energy procurement costs and where expected transmission flows are impacted by higher than normal hydro-electric energy dispatch.

Appendix H

Economic Analysis Assumptions

Assumptions

The majority of numbers used in the 30-year economic analysis were taken directly from the zonal results of the production cost model (PROMOD IV) prepared by Ventyx. Annual generation, purchases, sales, and loads in GWh were extracted from the production cost model. The annual costs associated with generation, purchases and sales were also extracted from the production cost model.

Transmission operation and maintenance costs and Renewable Energy Credits (REC) were not included in the production cost model but were considered in the economic analysis. Based on historical data, it is assumed that annual transmission O&M costs equal 10 percent of transmission investment. A discussion of Work Element 4 in Section 2 presents the transmission interconnection investment cost of $8,392,000. Therefore, the annual transmission O&M equals $839,200 escalated at 4 percent annually. A REC value of $5/MWh with escalation of 5 percent annually is used in the economic analysis.

The annual net costs in the economic analysis were discounted back to 2011 dollars. A 5 percent discount rate based on the January 2008 Office of Management and Budget report was used.

		Low Hydro Analysis (30 Year Total)			Base Hydro Analysis (30 Year Total)			High Hydro Analysis (30 Year Total)		
		Base Wind Case	Tribal Wind Case	Base Less Tribal	Base Wind Case	Tribal Wind Case	Base Less Tribal	Base Wind Case	Tribal Wind Case	Base Less Tribal
GENERATION/PURCHASES										
HydroGeneration	(GWH)	271,022.75	271,001.51	21.24	332,422.76	332,383.62	39.14	385,457.96	385,414.91	43.05
Wind	(GWH)	30,686.82	33,948.23	-3,261.41	30,686.78	33,948.19	-3,261.41	30,686.78	33,948.20	-3,261.42
Peaking Returns	(GWH)	9,747.00	9,747.00	0.00	9,746.98	9,746.96	0.01	9,746.99	9,746.99	-0.01
Western Purchases	(GWH)	72,111.72	70,278.83	1,832.89	51,563.01	50,379.02	1,183.99	32,122.24	31,337.11	785.13
Emergency	(GWH)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL GENERATION/PURCHASES	(GWH)	**383,568.29**	**384,975.58**	-1,407.28	**424,419.53**	**426,457.79**	-2,038.27	**458,013.97**	**460,447.21**	-2,433.25
LOADS/SALES										
NativeLoad	(GWH)	331,800.45	331,800.45	0.00	331,800.45	331,800.45	0.00	331,800.45	331,800.45	0.00
ExtCompanySales	(GWH)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Western Sales	(GWH)	42,140.29	43,445.15	-1,304.86	82,306.83	84,227.24	-1,920.41	115,545.17	117,882.45	-2,337.28
DumpEnergy	(GWH)	51.22	54.94	-3.72	58.74	63.38	-4.64	65.24	68.79	-3.55
TransmissLosses	(GWH)	9,579.96	9,678.77	-98.81	10,258.11	10,371.13	-113.02	10,608.02	10,700.58	-92.56
TOTAL LOADS/SALES	(GWH)	**383,571.92**	**384,979.31**	-1,407.39	**424,424.13**	**426,462.20**	-2,038.07	**458,018.88**	**460,452.27**	-2,433.39
GENERATION/PURCHASE COSTS/RECS										
HydroCost	(K$)	$7,393,322.93	$7,392,579.25	$743.68	8,955,091.89	8,953,693.27	$1,398.62	$10,705,377.37	$10,703,869.73	$1,507.64
Wind	(K$)	$2,069,043.69	$2,283,981.95	-$214,938.26	2,069,040.28	2,283,981.95	-$214,941.67	$2,069,040.76	$2,283,981.95	-$214,941.19
Western Purchases Cost	(K$)	$6,564,372.91	$6,407,265.14	$157,107.77	4,958,704.94	4,845,741.46	$112,963.48	$2,797,213.01	$2,734,451.11	$62,761.90
Western Sales Cost (Revenue)	(K$)	($3,078,169.46)	($3,155,524.34)	$77,354.88	(5,617,205.37)	(5,712,221.89)	$95,016.52	($8,331,811.85)	($8,440,955.87)	$109,144.02
NET GEN/PURCHASE COSTS	(K$)	**$12,948,570.07**	**$12,928,302.00**	**$20,268.07**	**$10,365,631.74**	**$10,371,194.79**	**-$5,563.05**	**$7,239,819.29**	**$7,281,346.92**	**-$41,527.63**
PRESENT VALUE COSTS (2011)										
Present Value Net Costs	(K$)	**$5,983,030.34**	**$5,981,846.85**	**$1,183.49**	**$4,589,942.17**	**$4,601,928.59**	**-$11,986.42**	**$3,496,623.37**	**$3,521,274.95**	**-$24,651.57**
Present Value Net Costs with RECs & Transmission O&M 50 MW	(K$)	**$5,983,030.34**	**$5,978,110.53**	**$4,919.81**	**$4,589,942.17**	**$4,598,192.36**	**-$8,250.19**	**$3,496,623.37**	**$3,517,538.67**	**-$20,915.30**

		Low Hydro		Base Hydro		High Hydro	
		Reference Wind	Base Wind	Reference Wind	Base Wind	Reference Wind	Base Wind
GENERATION/PURCHASES							
HydroGeneration	(GWH)	271,072.24	271,022.75	332,455.89	332,422.76	385,521.81	385,457.96
Wind	(GWH)	0.00	30,686.82	0.00	30,686.78	0.00	30,686.78
Peaking Returns	(GWH)	9,747.00	9,747.00	9,746.99	9,746.98	9,746.99	9,746.99
Western Purchases	(GWH)	92,180.19	72,111.72	66,167.10	51,563.01	41,960.65	32,122.24
Emergency	(GWH)	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL GENERATION/PURCHASES	(GWH)	**372,999.43**	**383,568.29**	**408,369.98**	**424,419.53**	**437,229.45**	**458,013.97**
LOADS/SALES							
NativeLoad	(GWH)	331,800.45	331,800.45	331,800.45	331,800.45	331,800.45	331,800.45
ExtCompanySales	(GWH)	0.00	0.00	0.00	0.00	0.00	0.00
Western Sales	(GWH)	31,789.17	42,140.29	66,520.27	82,306.83	95,093.32	115,545.17
DumpEnergy	(GWH)	47.38	51.22	55.67	58.74	60.62	65.24
TransmissLosses	(GWH)	9,366.19	9,579.96	9,998.11	10,258.11	10,280.55	10,608.02
TOTAL LOADS/SALES	(GWH)	**373,003.19**	**383,571.92**	**408,374.50**	**424,424.13**	**437,234.94**	**458,018.88**
GENERATION/PURCHASE COSTS/RECS							
HydroCost	(K$)	$7,395,114.05	$7,393,322.93	$8,956,210.51	8,955,091.89	$10,707,615.59	$10,705,377.37
Wind	(K$)	$0.00	$2,069,043.69	$0.00	2,069,040.28	$0.00	$2,069,040.76
Western Purchases Cost	(K$)	$8,317,529.28	$6,564,372.91	$6,278,504.78	4,958,704.94	$3,602,262.65	$2,797,213.01
Western Sales Cost (Revenue)	(K$)	($2,349,706.57)	($3,078,169.46)	($4,592,828.79)	($5,617,205.37)	($6,979,137.67)	($8,331,811.85)
NET GEN/PURCHASE COSTS	(K$)	**$13,362,936.76**	**$12,948,570.07**	**$10,641,886.50**	**$10,365,631.74**	**$7,330,740.57**	**$7,239,819.29**
PRESENT VALUE COSTS (2011)							
Net Present Value Net Costs	(K$)	**$6,093,512.69**	**$5,983,030.34**	**$4,631,136.83**	**$4,589,942.17**	**$3,475,428.84**	**$3,496,623.37**
Net Present Value Costs with RECs & Transmission O&M 50 MW	(K$)	**$6,093,512.69**	**$5,983,030.34**	**$4,631,136.83**	**$4,589,942.17**	**$3,475,428.84**	**$3,496,623.37**

		Base Hydro					
		Base Wind			Tribal Wind		
		With CO_2	No $C0_2$	No CO_2 Minus With $C0_2$	With CO_2	No $C0_2$	No CO_2 Minus With $C0_2$
GENERATION/PURCHASES							
HydroGeneration	(GWH)	332,422.76	332,238.00	-184.76	332,383.62	332,193.61	-190.01
Wind	(GWH)	30,686.78	30,686.82	0.04	33,948.19	33,948.19	0.00
Peaking Returns	(GWH)	9,746.98	9,747.00	0.02	9,746.96	9,746.96	0.00
Western Purchases	(GWH)	51,563.01	52,961.67	1,398.66	50,379.02	51,822.22	1,443.20
Emergency	(GWH)	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL GENERATION/PURCHASES	(GWH)	**424,419.53**	**425,633.49**	**1,213.96**	**426,457.79**	**427,710.98**	**1,253.19**
LOADS/SALES							
NativeLoad	(GWH)	331,800.45	331,800.45	0.00	331,800.45	331,800.45	0.00
ExtCompanySales	(GWH)	0.00	0.00	0.00	0.00	0.00	0.00
Western Sales	(GWH)	82,306.83	81,026.91	-1,279.92	84,227.24	82,884.81	-1,342.43
DumpEnergy	(GWH)	58.74	89.51	30.77	63.38	97.01	33.63
TransmissLosses	(GWH)	10,258.11	12,721.01	2,462.90	10,371.13	12,932.89	2,561.76
TOTAL LOADS/SALES	(GWH)	**424,424.13**	**425,637.88**	**1,213.75**	**426,462.20**	**427,715.16**	**1,252.96**
GENERATION/PURCHASE COSTS/RECS							
HydroCost	(K$)	$8,955,091.89	$8,948,800.22	-$6,291.67	$8,953,693.27	$8,947,261.16	-$6,432.11
Wind	(K$)	$2,069,040.28	$2,069,043.54	$3.26	$2,283,981.95	$2,283,981.95	$0.00
Western Purchases Cost	(K$)	$4,958,704.94	$5,428,208.89	$469,503.95	$4,845,741.46	$5,325,907.53	$480,166.07
Western Sales Cost (Revenue)	(K$)	($5,617,205.37)	($3,461,634.84)	$2,155,570.53	($5,712,221.89)	($3,502,195.86)	$2,210,026.03
NET GEN/PURCHASE COSTS	(K$)	**$10,365,631.74**	**$12,984,417.81**	**$2,618,786.07**	**$10,371,194.79**	**$13,054,954.78**	**$2,683,759.99**
PRESENT VALUE COSTS (2011)							
Present Value Net Costs	(K$)	**$4,589,942.17**	**$5,777,890.63**	**$1,187,948.45**	**$4,601,928.59**	**$5,820,099.12**	**$1,218,170.53**
Present Value Net Costs with RECs & Transmission O&M 50 MW	(K$)	**$4,589,942.17**	**$5,777,890.63**	**$1,187,948.45**	**$4,598,192.36**	**$5,816,362.89**	**$1,218,170.53**

Appendix I

Glossary

BaseHydro-one of three hydro scenarios that represents the median hydro generation
BaseWind-one of two wind scenarios that represents the base wind (723 MW) on Western's Balancing Area
Basin-Basin Electric Power Cooperative
Corps-US Army Corps of Engineers
CROD-Contract Rate of Design
Heartland-Heartland Consumers Power District
HighHydro-one of three hydro scenarios that represents the high hydro generation
ICOUP-Intertribal Council on Utility Policy
JTS-Joint Transmission System
LowHydro-on of three hydro scenarios that represents the low hydro generation
Master Manual- Missouri River Mainstem Reservoir System Master Water Control Manual
MISO-Midwest ISO
MBMPA-Missouri Basin Municipal Power Agency
MBSG-Missouri Basin Systems Group
P-SMBP-ED- Pick-Sloan Missouri Basin Program—Eastern Division
PROMOD-PROMOD IV Software by Ventyx
PTC-Production Tax Credit
Reclamation-Bureau of Reclamation
REC-Renewable Energy Credit
Section 2606-Energy Policy Act 2005, Section 2606
System- Missouri River Mainstem Reservoir System
TribalWind-one of two wind scenarios that represents the tribal wind (723 MW) on Western's Balancing Area
UGPR-Upper Great Plains Region
Western-WAPA-Western Area Power Administration
WHFS-Wind Hydro Feasibility Study

Appendix J

References

ABB Consulting, “Dakota Wind Transmission Study – Task 1: Non-Firm Transmission Potential to Deliver Wind Generation; Task 2: Transmission Technologies to Increase Power Transfer; and Tasks 3 and 4: System Impact Study and Transfer Capability Study” prepared for the Western Area Power Administration, June 15, 2005.

EnerNex Corporation and Windlogics Inc., "Final Report - 2006 Minnesota Wind Integration Study: Volume I" for the Minnesota Public Utilities Commission, November 30, 2006.

GENIVAR, “Montana Wind Power Variability Study” for NorthWestern Energy, September, 2008.

United States Army Corps of Engineers - Northwestern Division: "Missouri River Mainstem Reservoir System Master Water Control Manual: Missouri River Basin" revised March, 2006.

United States Department of Energy, et. al.: “20% Wind Energy by 2030: Increasing Wind Energy’s Contribution to U.S. Electricity Supply” May, 2008. DOE/GO-102008-2567

United States Department of Energy, Energy Efficiency and Renewable Energy, “Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007”, May 2008.

Utility Wind Integration Group, “Utility Wind Integration State of the Art” 2006 http://www.uwig.org/UWIGWindIntegration052006.pdf

Western Area Power Administration, Integrated System Customer Rate Brochure Proposed Transmission and Ancillary Service Rates Adjustment, April 2005, http://www.wapa.gov/ugp/rates/ISrates/ISRateBrochure.pdf

Zavadil, R.M. "Draft Report: WAPA Wind Integration Study" August 4, 2006.

Appendix K

Public Comments and Response to Comments on Draft WHFS

The following public comments and respective responses follow:

1) Yankton Sioux Tribe General Council Resolution No. 2009-008 –***No response required***
2) Harvest Initiative, Inc.
3) MRES
4) Fort Peck Tribes Assiniboine & Sioux
5) Xtreme Power Solutions
6) Mid-West Electric Consumers Association
7) Intertribal Council on Utility Policy
8) Western Area Power Administration Wind/Hydro Feasibility Study Public Comment Meeting Transcript

Where a response to comments refers to information in the existing report or resulted in a correction in the report, that text is shown in ***bold Italics***.

Box 248
Marty, SD 57361

(605) 384-3804 / 384-3641
FAX (605) 384-5687

OFFICERS:
ROBERT COURNOYER, CHAIRMAN
JOHN STONE, VICE CHAIRMAN
FRANCES "PUNCHY" HART, SECRETARY
LEO O'CONNOR, TREASURER

COUNCIL:
JODY ALLEN ZEPHIER
BASIL HETH
DENNIS RUCKER
GARY DRAPEAU
GREG ZEPHIER JR.

YANKTON SIOUX TRIBE
LAND OF THE FRIENDLY PEOPLE OF THE SEVEN COUNCIL FIRES
1858

YANKTON SIOUX TRIBE
GENERAL COUNCIL RESOLUTION NO. 2009-008

WHEREAS: The Yankton Sioux Tribe is an unincorporated Tribe of Indians that is not subject to t he Indian Reorganization Act of 1934; and

WHEREAS: The Yankton Sioux Tribe is an unincorporated Tribe of Indians operating under an amended Constitution and By Laws approved and amended on April 24, 1963, June 16, 1975 and March 23, 1990; and

WHEREAS: The Yankton Sioux Tribe Business and Claims Committee is the elected body constituted for the purpose of conducting the business of and serving the best interest of the Yankton Sioux Tribe; and

WHEREAS: The Yankton Sioux Tribe's Business and Claims Committee has contributed throughout the years to improving the standard and quality of life on the Yankton Sioux reservation; and

WHEREAS: The Yankton Sioux Tribe's General Council is the ultimate authority of the Yankton Sioux Tribe and government to government consultation will and shall occur at a scheduled General Council meeting according to the Yankton Sioux Tribe's Constitution and By-Laws; and

WHEREAS: Wind Energy Studies on the Yankton Sioux reservation have been completed by Mr. Bill Mitchell, Talon, LLC and Mr. Pat Spears, ICOUP and data, statistics and information collected on the Yankton Sioux Tribe is the sole ownership of the Yankton Sioux Tribe; and

WHEREAS: The Yankton Sioux Tribe's General Council desires to participate and partnership with Western Area Power Administration, Department of Energy to complete the Wind Hydropower Integration Feasibility Study; and

THEREFORE BE IT RESOLVED, that the Yankton Sioux Tribe's General Council approves and authorizes the partnership and collaborative efforts with Western Area Power Administration to complete the Wind Hydropower Integration Feasibility Study.

BE IT FURTHER RESOLVED, that Robert Cournoyer, CHAIRMAN and Frances C. Hart, SECRETARY of the Yankton Sioux Tribe's Business and Claims Committee are authorized and instructed to sign this resolution on behalf of the Yankton Sioux Tribe.

CERTIFICATION

THIS IS TO CERTIFY AND AFFIRM, the above and foregoing resolution was duly authorized and passed by the Yankton Sioux Tribe's General Council on the 5th day of January, 2009 at a meeting held at Fort Randall Casino & Hotel, Bingo Hall, Pickstown, South Dakota on the Yankton Sioux reservation, by a vote of 36 in favor, 3 opposed, MOTION CARRIED.

ATTEST

Robert Cournoyer, CHAIRMAN
Business and Claims Committee

Frances C. Hart, SECRETARY
Business and Claims Committee

Massey, Kim

From: Dustin J. Miller [dustin.miller@harvestinitiative.org]
Sent: Friday, February 13, 2009 8:00 AM
To: UGPWindHydroFS@wapa.gov
Subject: Harvest Initiative Comments

02.13.2009

Mr. Robert J. Harris

Regional Manager

Upper Great Plains Region

Western Area Power Administration

2900 4th Avenue North

Billings, MT 59101

Re: Crow Creek Sioux Tribe□s Involvement with the Wind & Hydro Feasibility Study (WHFS)

Dear Mr. Harris,

The Harvest Initiative, Inc. is submitting these comments regarding the WHFS in order to have the Crow Creek Sioux Tribe be considered part of the study. This reservation provides an environment ideally suited for such a feasibility project because all the elements are present that are sought after in the Energy Policy Act. Due to this confluence of multiple factors it is our belief that the Crow Creek Sioux Reservation provides an ideal location for the WHFS. Our organization is an Iowa based non-profit corporation doing economic development on the Crow Creek Sioux Reservation.

The elements possessed within the borders of the Crow Creek Reservation would provide a location that would satisfy the elements of Section 2606 of the Energy Policy Act. One of the largest transmission hubs in the study region rests in close proximity to the Big Bend Dam and just north of this substation lies some of the best wind resources in the United States. This location offers all the assets possible to ensure success of this feasibility project. The blending of wind energy and hydropower to determine the economic and engineering feasibility of such a project would be best suited in an environment that gives all the necessary support to ensure the success of the project. According to our observations, the cost and demonstration of a 50MW project on the Crow Creek Sioux Reservation gives the best opportunity to see the lowest cost for WAPA customers.

Another important aspect to consider is that the wind resource and transmission capabilities here on the Crow Creek Reservation were already studied under the Dakotas Wind Transmission Study. According to subpoint 6 of the amended version of the Energy Policy Act, this study is to be incorporated into the WHFS. We would like WAPA to consider that much of the work has been completed through this previous study and it showed that there is the possibility of a successful project here at Crow Creek. After weighing the possibilities of the various projects under consideration we would ask you to reexamine the information already provided through the Dakotas Wind Transmission Study to see that the Crow Creek Sioux Reservation would provide a location that would maximize the success of this undertaking.

Thank you for your review of our comments and please do not hesitate to contact me at 605.8706196.

Kind Regards,

Dustin J. Miller - Director of Development & Marketing

The Harvest Initiative, Inc.
PO Box 175
Fort Thompson, SD 57339

605-870-6196

dustin.miller@harvestinitiative.org
www.harvestinitiative.org

Response to comments submitted by Harvest Initiative on behalf of the Crow Creek Sioux Tribe

Thank you for your comments on the Draft Wind and Hydropower Feasibility Study Report. The comments suggest that Western should select the Crow Creek Sioux Tribe as the demonstration project site based on proximity to existing transmission facilities and previous study efforts. At this time, Western is not soliciting nominations for a demonstration project site. The legislative mandate for the WHFS report did not include making a determination for a specific demonstration project site. If a demonstration project is approved and funded by Congress, Western encourages the Crow Creek Sioux Tribe to participate in the yet to be defined demonstration project selection process. As stated in the Wind and Hydropower Feasibility Study (WHFS) Report, the Dakotas Wind Transmission Study (DWTS) was reviewed during the development of the WHFS work plan. Findings from the DWTS were included in the WHFS study as they were relevant to that effort - ***please see Work Element 4, Transmission System Evaluation*****.**

MISSOURI RIVER ENERGY SERVICES®

3724 West Avera Drive
PO Box 88920
Sioux Falls, SD 57109-8920
Telephone: 605.338.4042
Fax: 605.978.9360
www.mrenergy.com

February 13, 2009

Mr. Robert J. Harris
Regional Manager, Upper Great Plains Region
Western Area Power Administration
2900 4th Avenue North
Billing, MT 59101-1266

RE: Comments on Draft Feasibility Study Report Associated with Wind Hydropower Integration Feasibility Study

Dear Mr. Harris:

Thank you for the opportunity to provide comments on the Western Area Power Administration's (Western) draft Feasibility Study. Fifty-nine of 60 Missouri River Energy Services (MRES) members receive hydro power from Western. A power supply contract exists between each municipality and Western through 2020. Each municipality has a fixed demand and energy allocation Western which represents 25 percent to 90 percent of the municipality's total power supply. In aggregate, these municipalities represent over 20 percent of Western Upper Great Plains Region firm allocations. Thus any action that Western undertakes will have a direct impact on most of our members. As long as Western has firm fixed allocation responsibility, it is prudent to look at purchasing energy on a longer term basis to minimize risk exposure to the short-term market, regardless of hydro condition. The issue is finding the appropriate amount of generation given the generation resource type that Western is considering to supplement its existing resources.

MRES comments on the Draft Report are divided into the following study result areas as prescribed by Section 2606 of the Energy Policy Act of 2005.

1) ***Analysis and comparison of the potential energy cost or benefits to the customers of the Western Area Power Administration through the use of combined wind and hydropower.***

   The report does not spend much time on addressing wind intermittency and whether the intermittency was characterized appropriately to reflect the true costs of having to firm the wind when it is not generating due to Western's need to serve the load. Although, the Appendix demonstrates that EnerNex computed load following requirements, we do not know whether the costs of load following and other ancillary services were incorporated into the final analysis. The report recognizes that matching load and wind generation patterns is critical; however, a graphical representation of such seems to be lacking in the main report and executive summary. Furthermore, the report does not contain any graphical representation of forecasted hourly wind generation production by season to show the reader which hours during the day the wind benefit the customers by supplying load. Incorporating some graphics that address these issues, would be helpful to understand the character of the wind generation resource.

   The authors generally state that there is no significant risk to curtailment, but the fact is that there is risk and the probability of that risk produces cost exposure. The cost of curtailment needs to be factored in the cost/benefit to measure the impact to customer costs. High-hydro generation conditions, which essentially result in must take situations, increase the probability of having to curtail the wind generation. Since the flows are dictated by the Corps of Engineers (COE), the hydro generation would be determined by a schedule, if transmission is constrained, the wind generation would need to be curtailed. If Western is responsible for such a curtailment, which would likely be under a power purchase agreement, this would be an additional cost to the customer. The more wind MW that Western contracts for, the higher the probability of curtailment. The tribal addition is the last increment that Western adds in this study. This may exacerbate the curtailment problem.

To further complicate things, since the ultimate location and MW amount has not been finalized but just assumed, uncertainty would remain as to curtailment needed. This is an unknown that needs to be considered due to the fact that more federal/state/local agencies and regulations are increasingly exhibiting jurisdiction of the placement and MW in specific locations. If MWs are not placed in the study location more (or less) curtailment may occur.

The study utilized very simple assumptions with regard to the transmission costs associated with the interconnection and transmission service for the new wind generation resources. The study assumed that there were already existing issues that would need to be mitigated. While that may be the case at this site, there is certainly a possibility that other sites would result in different, potentially significant upgrades being required. In the past, all Integrated System load has paid for network upgrades associated with new wind generation resources being designated as a network resource. With Western not allowed to enter into power purchase contracts longer than five years, there is a concern that the network load may end up paying for the transmission upgrades when in reality it is possible that the new wind generation resources may not be serving network load beyond the five years initially contracted. The implications of this should be considered by Western, and potentially addressed by the Integrated System by making modifications to the transmission tariff minimizing the risk to network customers if such an event occurred.

MRES believes short term power supply arrangements need to be in place to limit the risk exposure to the real-time market. However, wind may not be the best option. MRES is concerned about the operational characteristics of this resource which translate to reflecting the true cost/benefit of such a resource. On the surface, it looks as though this study is limited to wind opportunities and not looking at bidding other resources which would be prudent and in the best interest of the customer's paying the costs.

2) ***An economic and engineering evaluation of whether a combined wind and hydro system can reduce reservoirfluctuation, enhance efficient and rel iable energy production, and provide MR management flexibility;***

The Corps of Engineers (COE) directs the regulation of the reservoir system to serve Congressionally- authorized project purposes. The Master Manual provides the guidelines for operating the reservoir system. Therefore, MRES recognizes that Western does not have much flexibility in the generation operations characteristics and would not expect additional flexibility with wind generation since this may alter the management of the reservoir system. The authors of the report recognize and thus the comments are only confined to 2.5 pages in the report. The operational characteristics of the wind generation would need to be subject to control because of the very limited operational control of the hydro generation. Therefore, some hardware and software capabilities, under the direction of Western, would need to be included to allow such a configuration to exist.

3) ***If found feasible, recommendations for a demonstration project to be carried out by Western in partnership with Indian tribal government or tribal energy resource development organization and Western customers to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to Western.***

The study findings suggest there is an economic saturation point at 300 MW or less when wind generation is used to meet Western's load. When comparing BaseWind to TribalWind, the incremental 50 MW (to 350 MW total for Western's load) has the potential for a negative economic impact in the base and high hydro year (-$400k per year and -$822k per year, respectively) with relatively little positive impact in low hydro year ($39k per year). Thus, MRES concludes a high likelihood of this added 50 MW resulting in a cost impact to Western customers.

If a demonstration project is authorized, it should be a fraction of the 50 MW that is recommended (perhaps 20 MW) since the tribal wind, which is the last increment, has more potential for cost impacts than the previous wind added to supply Western load. Also, the lower the installed amount for demonstration purposes, the more likely curtailment would not be an issue which is always a difficult issue to rectify in power purchase negotiations.

Reliability of the wind generation units is a real concern. MRES first invested in this technology in 2002, starting out with two 900 kW and two 950 kW units. One of the reasons of the investment was to obtain operations and maintenance experience in dealing with this generation resource before committing to a larger project (20 to 40 MW). MRES has experienced the frustration in dealing with this technology, ranging from issues related to particular brands of turbines, part availability, to operations and maintenance procedures, all which have an effect on the reliability of this resource. Some of the issues are in design and mechanical failure of certain brands while others are more controllable from an operations perspective; that is, as long as appropriate personnel and planning are in place. We advise a similar approach for those initially investing in the technology: invest first on a smaller scale, once more experience is achieved, more could be built with less risk.

Another item to consider is the expiration of the current Western power supply contracts and renewals. Current contracts expire in 2020 and no discussions have taken place as to the character of future firm allocation. One alternative to firm customer's purchases is to reduce the allocation based upon a lower hydro year. Another possible alternative to be studied is to move from a firm allocation to allocating each customer a pro-rata share of the actual hydro-generation. This is done in other federal power marketing programs. In these examples, Western would not necessarily need the wind resource. The customer would be responsible for replacing the lost resource.

4) ***An identification of the economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership; and the manner in which a Federal-tribal-customer partnership could contribute to the energy security of the United States.***

The northern plains are abundant with wind resources, on and off tribal lands. Western customers are more concerned about cost impacts than the physical location of the generation resource. In the final analysis, if tribal energy is more expensive than a non-tribal project, what is the value proposition to the Western customer to offset the increased cost?

Secondly, MRES does not agree with the study's un-researched conclusion that wind would improve national energy security. Although, the United States imports 15 percent of the natural gas it uses, 80 percent of that is produced in Canada which in not a national security threat to the

United States. Crude oil is a little different. Today about two-thirds of the oil is imported and seventy percent of that is used for transportation. However, only 1.5 percent of the electric generation in the US in 2006 was from distillate fuel. Therefore, the argument of increasing national security has not been proven and cannot be concluded in only one page of the draft report. Perhaps a better argument could be made by stating that wind would preserve the U.S. natural resources for future generations.

MRES appreciates the opportunity to provide comments on this Feasibility Study. Although, MRES outlined many concerns, in general, MRES is concerned about using an intermittent resource (i.e. wind) to replace lost hydro generation in a physical market such a Western's. Before acquiring much more than the 50 MW of wind generation that Western has purchased from Basin Electric, MRES advises that further study be conducted to determine the exact economic saturation point of wind purchases. Secondly, Western customers should not be required to pay more than the market rate for a certain wind project if wind generation is more cost effective than traditional sources.

Sincerely,

Thomas J. Heller

Thomas J. Heller, P.E., MBA
Chief Executive Officer

Response to comments submitted by Missouri River Energy Services

Thank you for your comments on the Draft Wind and Hydropower Feasibility Study Report. The basic premise behind the Purchase Capacity Bandwidth was to provide a sound approach to estimate a reasonable capacity for which wind energy could be used to supplement future energy purchases while considering the associated impacts. To this end the sub hourly analysis resulted in regulation and load following reserve requirements and the associated costs from the market simulations were incorporated into the analysis - ***please see p. 2-37, 2nd paragraph under Reserve Requirements for Wind Penetration Levels***. In addition, wind/load combinations were used in the PROMOD simulations - ***please see p. 2-36, 30-Year Load and Wind Forecasts***.

With regards to the potential for curtailment of wind, the study noted that transmission grid impacts are similar to those observed in the Dakota Wind Transmission Study; a 50 MW tribal wind project addition utilized as studied does not require overall grid additions over and above those that would be needed for the first 300 MW of non-tribal wind projects to be placed on Western's system - ***please see p. 2-33, Work Element 4 Conclusions***. Similarly, the PROMOD nodal analysis did not identify any additional flowgate constraints when adding the 50MW tribal wind utilized as studied that were not already constrained by the 300 MW of non-tribal wind - ***please see p. 2-39, Results from PROMOD IV Market Simulations***. Further, while not specifically addressed in the study, under above normal hydro generation conditions, the lead time associated with hydro scheduling/moving water (compared to wind forecasts) would allow Western an opportunity to market excess generation to mitigate wind curtailment. With regards to assessment of the risks associated with curtailment, this analysis provides a basic assessment of that risk. However, as generally known in the industry, the complex dynamics of transmission system operations and the varied conditions leading up to curtailment actions are difficult to predict much less model. For the purposes of this study, Western believes the analysis provides useful information with regards to assessing the level of risk associated with wind integration under the context of the study as performed. The addition of 50 Mw's of tribal wind, as compared to the reference case, did not result in increased wind curtailment - ***please see p. 2-39 Nodal Results***.

The simplified transmission cost assumptions utilized in the WHFS do present potential challenges if and when a demonstration project is approved and funded by Congress. For this very reason, the WHFS report clearly noted this study did not take the place of Western Open Access Transmission studies - ***please see Conclusions, p. 2-33***. Concerns of Integrated System cost responsibility can be taken into account during demonstration project criteria development. Western does have the authority to enter into contracts longer than five years, but to date, has chosen to utilize short term arrangements to purchase energy to meet contractual firm power obligations during periods of drought.

Both short-term and long-term power supply arrangements, also mentioned in your comments, can be considered during the criteria development process. The legislative mandate was to consider tribal wind energy integration over a 30-year period. Further, the study did not assume all requirements would be provided by wind - ***please see Section 2 Work Element 2***. The comments also assume that the 300 MW of wind energy is under a long-term contract. Currently, no long term contracts for provision of wind energy to Western exist. The recommendation for additional study to look at the economic saturation point will provide better insight into the quantity and term of any wind contracts considered beyond a demonstration project.

Wind generation unit reliability issues and generation production responsibility can be considered in the demonstration project criteria if authorized and funded by Congress. With regards to Western's experience in wind energy, Western would anticipate utilizing its expertise in the integration and marketing of the power in conjunction with the hydro system versus the actual operation of the wind project. The recommendation for a 50 MW demonstration project is based on several factors. For a demonstration project to be truly meaningful with regards to assessing cost and benefit, Western and the WHFS project team believes that 50 MW represents a minimal size of a project to fulfill the objectives of a demonstration project.

Since the structure of contractual arrangements post 2020 has not been determined, the assumption used for the study was the continuation of existing contracts. As noted in the final recommendations, any costs of the demonstration project beyond what Western would have normally paid for like energy should not be borne by Western's ratepayers - ***please see p. vii***.

The WHFS Report reference to improving national energy security issue implies a broad perspective that any resource that expands the domestic fuel options beyond foreign fuel will enhance national energy security.

FORT PECK TRIBES

Assiniboine & Sioux

February 12, 2009

Mr. Robert Harris
Regional Manager
Upper Grant Plains Region
Western Area Power Administration
2900 4th Ave. North
Billings, MT 59101-1266

Dear Mr. Harris:

In accordance with Federal Register/Vol. 73, No. 241/Monday, December 15, 2008, Notice. We would like to ask your consideration of our comments on the Draft Feasibility Study Report that was conducted in accordance with mandate in Section 2606 of the Energy Policy Act of 1982 as amended by Section 503(a) if the Energy Policy Act of 2005. Your Project team is to be commended for all the work that went into preparing the draft report.

We would like to encourage your office to consider two or more 50 megawatt wind farms in your recommendation to the Congress for the pilot programs outlined in the legislation. In addition, to a possible 50 megawatt farm in the Dakotas, we would like to see another 50 megawatt wind farm on the Fort Peck Tribes Reservation that could be a part of the west transmission system. The basic reason for our strong recommendation for this facility is that the Department of Energy financed a detailed study titled "Feasibility Study for Wind Energy Project" dated December 1996 that looked at the wind data and transmission facilities in detail. With the many advancement in wind technology that have occurred recently and the great need for renewable energy development we believe with great wind regime in Northeastern Montana we think this could be a great asset in providing firming energy for the hydro system in low water years plus it would be a great national asset to help get the U.S. off oil dependency. The other major benefit of development on the Fort Peck Tribes Reservation is that Western has transmission facilities in the area that could take the energy into the system with no major costs other than interconnection costs.

We were quite concerned about the statement made in the recommendation that said you needed to be sure there would be no adverse effects on the existing preference power customer's rates. We find this statement quite insincere when a person looks at the huge financial benefits currently going to the power customers as a result of the non-development of the planned irrigation in the PSMBP for over 50 years. This particular item has not only provided nearly 500 megawatts of generating capacity at no capital cost. There has also been a significant amount of additional energy available for marketing as a result of reduced water depletions associated with the delayed irrigation.

Poplar, Montana 59255 P.O. Box 1027 (406) 768-5155

It appears if we are going to develop renewables at the rate proposed by the Administration and the Congress in the 2009 Recovery Plan a complete new approach to evaluating hydro operations needs to be looked at similar to the process that was done in the 1970's when the nation was faced with the oil crisis. At that time the Bureau of Reclamation in cooperation with the Corps developed an oil conservation program, which saved millions of barrels of oil through a modified hydro generation schedules. It would appear that this would tie into the Corps plan to prepare an EIS for the Missouri River Ecosystem Restoration Plan that was announced in the Federal Register on January 26, 2009.

One item not covered in the report but very important to the Fort Peck Tribes is the opportunity to enhance the employment in the area that is truly distressed.

We want to thank you in advance for your serious consideration of recommending a 50 megawatt wind farm on the Fort Peck Tribes Reservation.

Sincerely,

A. T. Stafne

A.T. Stafne
Chairman
Fort Peck Assiniboine and Sioux Tribes

Response to Comments submitted by Fort Peck Tribes Assiniboine & Sioux

Thank you for your comments on the Draft Wind and Hydropower Feasibility Study Report. Western limited its recommendation to a 50MW Tribal project based on the 300MW of non-tribal wind currently in negotiations for a duration of approximately 5 years. Additionally, as the study results indicated, quantities of wind energy over 300MW identified diminishing favorable economics under average conditions over the 30 year timeframe. The point at which those benefits begin to diminish was not identified with the current study and was the basis of the recommendation for additional study to look at the economic saturation point. As stated in the study, the assumption was that after completion of the five year term of those contracts, the 300 MW of wind energy could be replaced by Tribal wind energy projects - ***please see p. ii third paragraph***. Western's recommendation for a 50 MW demonstration project was based on acceptable risk of a long term contract given the unknowns of the economic saturation point for wind energy.

With regards to your stated benefit to power customers that is a result of the *"…non-development of the planned irrigation system.*" This comment is unrelated to the wind hydro study since evaluation of authorized reclamation project development was not an objective of the WHFS.

Details of Western's role in any 2009 economic stimulus proposals have not been determined. It would be premature to predict changes that may impact the operating characteristics of the Missouri River Dams as a result of the Missouri River Ecosystem Restoration Plan at this time. The comments also suggested that external economic benefits were not addressed. Given the lack of site specific plans, partnership agreements or contractual arrangements between Tribes and co-developers, detailed external benefit analysis could not be assessed. However a summary benefit was provided - ***please see discussion in Direct Benefits, p. 4-1, 4-2***.

-----Original Message-----
From: Greg Hamilton [mailto:ghamilton@xtremepowersolutions.com]
Sent: Thursday, February 12, 2009 2:16 PM
To: UGPWindHydroFS@wapa.gov
Subject: Xtreme Power----re: Wind/Hydro Integration Feasibility Study

Mr. Robert J. Harris

I would respectfully request that you consider Power Storage. Not only would our technology smooth out the loads from the respective wind turbines, individual and cumulative, power generation production but addition our systems serve to address the following areas that your "Wind/Hydro Feasibility Study" January 13,2009 report notes as issues against Wind Generation:

"Wind may have short term impacts on real-time operations and could effect scheduling over several days"
"The addition of wind is not expected to provide additional flexibility in overall reservoir system management"

Our Xtreme Power System is a complete turnkey solution that provides an active Power Storage Solution that consists of our PowerCell's and an Energy Management System that can be monitored or controlled remotely with SCADA. We address and offer a solution for the power needs that are currently at issue for Wind Farms and Utility Grids. Systems include but are not limited to Voltage Control, Frequency Control, Peak Demand Periods, Load Following, Curtailments, etc.

In addition to having added benefits of a more stable, predictable power supply, Xtreme Power Systems power storage provides the Security of a known monitored and "active" Uninterrupted Power Supply connected to the grid in a specific area or areas that would help address our National Security risks.

In respect to the second part of the complete Hybrid solution. The Hydro-Generation portion would serve in a more productive capacity when it is additionally utilized with Power Storage. As you are aware, the near constant flow of water and the resulting Power that is generated is not following the highest energy demands that are required in the day light hours. Without further costs, our system would utilize the Night
Time Power Generation of Power that would normally Not be Utilized. Again, with Power Storage this energy that is not being utilized can be put to better use by Storing the Power for two, four, six or more hours. The Power then can be used with it's highest and best use for timed distribution at Peak Demand times or at other times of concern for Grid Stabilization. An optimum Hybrid System utilization would include your Wind Generation / Hydro-Generation and would possess built in redundancies from our Xtreme Power EMS which would include our Power Storage.

The PowerCell is a clean energy storage product that has merged "characteristics" of an ultra capacitor and a battery on steroids. It provides high efficiency energy storage while having almost no internal resistance (no heat losses). A notable characteristic for the PowerCell is its ability to provide the same designated power as needed until it is completely depleted of its energy. Complete systems with power storage serve to enhance performance and also provide increased efficiencies to technologies that have transient or intermittent power supply, ie. solar, wind, etc.

Some of the other characteristics of our patented PowerCell include being manufactured in a solid state as a deep cycle product that does not overheat while having a broad temperature operating range. The PowerCell is a silent operational product that can be used in any location, interior or exterior, with a small footprint. Along with the ability to recharge in quick and various time periods other qualities include being 97% recyclable, maintenance free, emitting no toxic gases (non haz-mat, DOT & DOD) and having a very long life cycle.

Our Energy Management Systems electronics have a fifty year history while our PowerCell's have a ten years history. Please get back with us for further information.

Best Regards

Greg Hamilton
Xtreme Power Solutions
1120 Goforth Rd.
Kyle, Texas U.S.A. 78640

512-442-4444 Direct
www.xtremepowerinc.com

Other Products Offered by Xtreme Power

LOAD LEVELING is the ability to time-shift the consumption of electricity. Xtreme Power can store electricity during low cost rate periods for use during high cost times. These primary power units are custom built on unique technology ranging from the 100 KW through the 50 MW system. These units operate in the 95% efficiency range (power in or power out).

BLINK-LESS UPS Always on blink-less Uninterruptible Power Supply (UPS) is available to provide a unique power back up, capable of carrying building-sized loads.

ENABLING Renewable power solutions that ensure predictible power delivery.

Xtreme Power
1120 Goforth Road
Kyle, Texas 7840
512-268-8191
888-263-5870 Fax
www.xtremepowerinc.com

Xtreme Power

POWER ANYTIME ANYWHERE

⇨ Reduce Curtailment
⇨ Increase Revenue
⇨ Reduce Wind Excursions
⇨ Increase Asset Utilization
⇨ Reduce Wind Variability
⇨ Potential Auxiliary Services Revenue

WIND POWER MANAGEMENT SYSTEM

BENEFITS:

- ⇨ Eliminate Wind Curtailment
- ⇨ Control Wind Excursions
- ⇨ Power Certain
- ⇨ Peak Power Revenue
- ⇨ Maximize Transmission Constraints
- ⇨ Power Factor Correction

FEATURES:

- ⇨ From 1 MW to 50 MW
- ⇨ Intelligent Wind Power Controller
- ⇨ Network Computer and Web-based Interface
- ⇨ Fully Programmable
- ⇨ Hot Swap the Power Cells
- ⇨ 95% System Efficiency (Power In or Power Out)
- ⇨ Complete Range of Input and Output Voltages
- ⇨ DC Pack Voltage from 12 to 1200 VDC
- ⇨ High Peak Power Capability
- ⇨ No Special Siting Requirements
- ⇨ Turn-key Power Systems

Xtreme Power

POWER ANYTIME ANYWHERE

Response to Comments from Xtreme Power Solutions

Thank you for your submittal, the study did not consider or specify supplemental technology to benefit wind integration. Consideration of the proposed technology or similar could be included in Tribal demonstration project proposals if and when authorized and approved by Congress.

Mid-West Electric Consumers Association

4350 Wadsworth Blvd., Suite 330, Wheat Ridge, CO 80033
Tel: (303) 463-4979 Fax: (303) 463-8876

February 13, 2009

Mr. Robert J. Harris
Regional Manager
Upper Great Plains Region
Western Area Power Administration
2900 4th Avenue North
Billings, MT 59101-1266

Dear Mr. Harris,

The Mid-West Electric Consumers Association appreciates the opportunity to comment on the Western Area Power Administration's ("Western" or "WAPA") draft Wind and Hydropower Feasibility Study (WHFS).

The Mid-West Electric Consumers Association was founded in 1958 as the regional coalition of consumer-owned utilities (rural electric cooperatives, public power districts, and municipal electric utilities) that purchase hydropower generated at federal multi-purpose projects in the Missouri River basin under the Pick-Sloan Missouri Basin Program.

Mid-West recognizes the potential for wind power development in the Pick-Sloan Missouri Basin Program ("Pick-Sloan"). The study here, mandated by the Energy Policy Act of 2005 is but one step in assessing how this wind potential can be developed. Mid-West offers the following comments to Western on this study:

Background on Western Balancing Area Operations: The WHFS draft study does not identify Native American tribes as preference entities. Why? Though the tribes in Pick-Sloan do not have utility responsibility – normally an additional criterion defining preference eligibility – they have been deemed qualified to receive federal power. Mid-West and its members supported allocations to Native American tribes in the extension of contracts in 2000. In fact, Mid-West and its members came up with the "bill crediting" concept to ensure that the tribes received the maximum Pick-Sloan benefit, avoiding additional costs that would have had to be imposed as a result of decisions and policies of the Federal Energy Regulatory Commission (FERC). Western's extending preference allocations to tribes does not confer any "super" preference status to the tribes, but does make them eligible to receive Pick-Sloan benefits on equal footing with other preference entities.

The description of Western's marketing area is incomplete. For instance, Western markets federal power in the entire state of Nebraska, albeit from the Eastern and Western divisions of Pick-Sloan. Though the study was conducted in the Eastern Division of Pick-Sloan, the draft WHFS should clearly identify the Western Division marketing area as well.

There is similar confusion in describing pre-1959 federal power in Pick-Sloan. While it is true that the United States Bureau of Reclamation ("Bureau" or "Reclamation") *marketed* power to Pick-Sloan firm power customers, the Bureau was marketing power generated at Bureau multi-purpose facilities and U.S. Army Corps of Engineers projects in the region. The Bureau's marketing responsibilities were assumed by the Western Area Power Administration with its creation pursuant to the Department of Energy organizational act.

The draft WHFS states that Western's Upper Great Plains Region markets 12 billion kilowatt-hours of firm energy. That overstates firm power marketing commitments of Western.

Western's draft study looks at three different generation scenarios: high (1997), median (2000), and low (2005), looking at a ten year period and then repeating that ten year period three times to create a thirty year model for each scenario . The high and low scenarios chosen are not really representative. Furthermore, some of the years used in the modeling represent generation under the Corps of Engineers' old Master Water Control Manual ("Master Manual"). The current Master Manual does not provide the same generation pattern or generation benefits to hydropower. Some of the Corps' new guidelines on water releases for navigation have significantly altered hydropower generation.

The intermittent nature of wind generation makes it difficult to assess how much wind generation would be able to contribute to total Pick-Sloan generation during low hydropower generation. In assessing the contribution that wind generation might make in the Pick-Sloan Missouri Basin Program, the study may not have sufficiently recognized that the dams' load-following capabilities are already used in meeting firm power contract obligations.

The draft study discusses a Federal-Tribal-Customer partnership, but fails to describe Western's customers' roles in this partnership. How would Western's other customers participate in this partnership?

Since the study does not identify specific sites for wind generation, it is difficult to assess what impacts there may be on the transmission system.

Before proceeding to a proposed demonstration project, Western needs to address these concerns with more detailed work. If the additional analysis shows that the Pick-Sloan Missouri Basin Program would benefit from a Federal-Tribal-Customer partnership, Western should propose a carefully designed demonstration, but must adhere to some basic principals in moving forward.

The demonstration project cannot adversely impact system reliability or firm power customers' costs. Recognizing that a demonstration project is testing a number of hypotheses and the uncertainty that goes along with that, wind generation costs in excess of Western's normal market purchases should be identified and must be deemed non-reimbursable.

There should be no subsidy of wind generation by Western's firm power customers. Wind generation purchases should not compromise Western's surplus sales during high hydropower generation periods.

Thank you for considering these comments.

Sincerely,

Thomas P. Graves
Executive Director

Response to Comments from Mid-West Electric Consumers Association

Thank you for your comments on the Draft Wind and Hydropower Feasibility Study Report. Several comments identified suggested omissions in the report. The first, Native American Tribes should have been identified as preference entities. The report has been corrected to include Native American Tribes – ***please see the first paragraph on p. 1-6.*** The second identified a failure to recognize the Western Pick-Sloan Marketing area. The text has been revised to identify the Marketing area of the Pick-Sloan Western Marketing Division - ***please see the third paragraph on p. 1-6.*** The third comment referenced an omission of the marketing of Reclamation and U.S. Army Corps of Engineers energy. The text has been revised to include the marketing energy from U.S. Army Corps of Engineers facilities – ***please see p. 1-6.*** The fourth comment referenced an overstatement of firm power marketing commitments. The first sentence under section *Delivering Western' Hydro Power* has been changed to approximately 2000 MW of firm capacity – ***please see p. 1-7***.

The selection of the high and low scenarios was intended to provide extreme ends of a range in order to frame the production modeling efforts for this study. While years selected for analysis do not all correspond to current Master Manual provisions, the need to use historical data was considered more important than the differences resulting from the Master Manual variations in this analysis. The energy patterns obtained from the historical data for the high and low years were the critical component. Given the gross magnitude of differences in the hydro scenarios selected – we believe they do serve as helpful reference points for the economic analysis. Additionally, given that the integration bandwidth does not solely rely on either of these points as absolute values we believe the integration bandwidth identified in the study would not vary significantly as a result of the change in generation patterns between the "old" and "revised" Master Water Control Manual. Further, we discussed your identified concern with representatives from the Army Corps of Engineers and they support the approach used in the WHFS.

The correlation of wind/load patterns was a significant component used to evaluate wind energy's contribution in the production modeling effort - **please see discussion under 30-year Load and Wind Forecasts, p. 2-36**. By matching the wind forecasts, load patterns and hydropower production schedules the WHFS did assess the contribution wind could make in the Pick-Sloan Missouri Basin Program. Through the use of the historical hydro generation data, the study did incorporate the dams load following capabilities. The objective was to integrate non-firm wind generation, when available, and determine the cost / benefit of that energy as compared to traditional purchases of energy. Under the scenarios and conditions studied, a long term benefit did exist under the low and base hydro scenarios.

In response to how Western's other customer would participate in a Federal-Tribal-Customer partnership, Western has historically sought customer input with regards to important matters affecting its customers. Western will continue to seek customer input as an integral part of Western's partnership with its customers. While the specific details of a demonstration project have not been determined, an appropriate level of customer interaction/participation will be included in any demonstration project process, consistent with and if authorized and funded by Congress to address many of the concerns noted in your comments.

Western agrees that the ultimate impacts to the transmission system could not be definitively determined in the WHFS. However, given the need to address potential impacts, one specific site was used for the transmission analysis - ***please see Work Element 4, Tribal Wind Case, p. 2-30***. This case was selected as a representative project for analysis purposes. Project site selection will be part of a demonstration selection process to be defined when a decision regarding the demonstration project is reached. Specific information relating to the actual wind sites was excluded from public review, in response to a commitment of confidentiality to the site proponents. Further, as noted in the WHFS report – detailed transmission assessment information was excluded in response to FERC Standards and Codes of Conduct and protection of Critical Energy Infrastructure Information. Additionally, as stated in Work Element 4 of WHFS, any demonstration project would be subject to Western Open Access Transmission Tariff - ***please see p. 2-27***.

Western concurs with the intent of your closing statements as evidenced by the overall approach, conclusions and recommendations contained in the WHFS.

Mr. Robert Harris, Manager

Upper Great Plains Region

Western Area Power Administration

2900 4th Avenue North

Billings, MT 59101-1266

WAPA Wind and Hydropower Feasibility Study Comments 2-13-09

My name is Patrick Spears, President of the Intertribal Council On Utility Policy, representing fifteen (15) tribes in the Northern Plains.

The Intertribal Council On Utility Policy, or Intertribal COUP, is a non-profit intertribal policy forum, consisting of fifteen northern Great Plains Tribes, including the Cheyenne River Sioux, Flandreau Santee Sioux, Lower Brule Sioux, Northern Arapaho, Oglala Sioux, Omaha Tribe of Nebraska and Iowa, Rosebud Sioux, Sisseton-Wahpeton Oyate, Spirit Lake, Standing Rock Sioux, Three Affiliated Tribes of Ft. Berthold (Mandan, Hidatsa and Arikara), Turtle Mountain Chippewa and Yankton Sioux Tribes. These federally recognized Tribes reside on reservations in North Dakota, South Dakota, Nebraska, Iowa and Wyoming.

Of these fifteen (15) tribes, eight are participating in the 400 MW Intertribal Wind Project proposed by Intertribal COUP. I offer greetings to all and a wish for a Happy New Year of fresh wind in our environmental and economic future.

Intertribal COUP thanks Mr. Tim Meeks, the Administrator of the WAPA for his forward thinking and support for the WHFS prior to an additional appropriation of funds to complete the study. We also appreciate the work of Mike Radecki, the Wind and Hydropower Feasibility Study (WHFS) Coordinator, Stanley Consultants, and the task force for their input and oversight in the conduct of the study.

The discussion of integrating distributed tribal wind into the federal grid takes place in the context of the rapid consumer, environmental and regulatory changes that are overtaking the energy industry, with regard to energy independence, energy security, the coming cost of carbon, and reduction of green house gases and other polluting emissions, addressing climate change and dealing with the persistent severe drought being experienced in the West and especially in the watershed area of the Upper Missouri River, along with the need for additional energy generation for the region. It is in this context that I offer these comments.

Reduced hydropower generation due to severe and persistent drought requires Western Area Power Administration to supplement its power supplies by purchasing additional coal power. Climate scientists understand that the CO_2 and other emissions associated with increase combustion of coal and other fossil fuels increase the levels of green house gases in the atmosphere and are forecasting that the impacts of global warming for the region are quite consistent with the shifts in precipitation and increased drought and drying throughout the Northern Great Plains we see today. If the climate scientists are correct, we should not expect the future run of the river to look like the last 100 yrs as reflected in our historical record, and certainly not leaning to the 30 wet year extreme. In fact, the forecasted case of 30 predominantly dry years is a more reasonable climate and hydrological scenario for the upper Great Plains.

The long term "natural hydrologic cycle" over the past 2,000 years demonstrates a fairly clear fluctuation between predominately "wet" and "dry" cycles which have lasted a century or more. The past century and a half has been one of the "wet" periods. This is the period of settlement on the Great Plains, and despite period decadal droughts, it has been predominately "wet" when compared to the long term historical trends. Consider that all that has been built -- cities, agricultural infrastructure, industrial economies and ways of living since settlement over the past 130 years -- have occurred during the most recent wet cycle. We take this particular "natural" point in the cycle as "normal". Science and the past long term hydrologic cycles would suggest that it is by no means a fixed "normal". Whether we look to current concerns about climate change or the long term natural cycles, climate can not be held as a constant, and water is the principle critical variable.

[See research of the EERC in Grand Forks, ND on such natural cycles, and "Extreme Swings in Climate Cycles Could Jeopardize the Socioeconomic Stability in the Northern Great Plains Region" http://www.undeerc.org/newsroom/newsitem.asp?id=211 inserted below. This is without any consideration of climate change due to "global warming".]

The rules of the electrical road have been written following the particular characteristics of specific generation which have already secured a place on the grid, namely, quickly dispatchable hydropower and long ramping lignite coal.

Federally hydropower generated by the Bureau of Reclamation or the Corps of Engineers is now of limited quantity due to drought conditions in the watershed, but provides relatively clean energy, with great dispatchability as a renewable resource. It also enjoys a primary legal right to be on the federal Western Area Power Administration transmission lines since it is generated from government instrumentalities, i.e. the federal power dams. It also is an intermittent or variable resource given relative availability of water flowing into the river system above the dams. Hydropower utilizes water in its generation of power. While it does not remove water from the river system, it does "consume" it in a manner of speaking at each generation point (reducing its potential energy by the reduction of altitude above sea level), making it no longer available at the previous generation site. Hydropower generation has extracted considerable costs paid primarily by the Tribes along the Missouri River.

While we are generally supportive of the research and data collection in the study, we are disappointed with the conclusions of the WHFS, as its focus was more limited that expected. The inclusion of the authorizing language of the WHFS in the Energy Policy Act of 2005 was due largely to the proposal by Intertribal COUP requesting the study with WAPA, our federal treaty partners, to study the merger of intertribal windpower and federal hydropower in a partnership that would have considerable environmental and economic benefits to the tribes and the federal government. It was the intent of COUP, which we believe was shared by Congress, to have a broader focus to include more data on the dispersed generation at eight tribal sites, and interconnection capacity on the WAPA grid system as well as more emphasis on the economic benefits of the purchase of intertribal windpower as supplemental power purchases.

It was the hope of the Intertribal COUP Tribes for a more coordinated study on the economics of purchase of tribal wind energy and the interconnection at **each** COUP reservation site with above average wind resources, that were deliberately selected near existing WAPA substations. However, only the Yankton site was used as a model for any of the eight COUP sites in the Intertribal Wind Project.

The study did not focus on the overall wind interconnection capacity of the WAPA system. It is based on the economics of wind power purchases by WAPA over a ten year period based on supplemental power purchases in high and low water level years. Although the amounts and costs of annual of annual power purchases by WAPA were not identified, it was stated by the consultants and supported by WAPA at the public comment meeting on January 13, 2009 that a baseload of coal fired power was assumed resulting in a limited purchase of windpower according to current economics of WAPA supplemental power purchases projected over the next twenty years.

Intertribal COUP believes that the economics of fossil fuel generation are going change due to increased costs as a resultant of environmental pollution valuation, particularly carbon costs. We also believe there should exist, more capacity in the transmission system for intertribal windpower, and that this capacity and economic benefit will only increase in the near future. As promised by WAPA and the consultants at the public comment meeting, we are awaiting the information supported by the research data on the amount and cost of coal fired power to more clearly understand the economics as to why only 350 MW of wind energy can be purchased as supplemental hydropower, with only 50 MW of tribal windpower.

It was further disappointing that the study identified that WAPA is negotiating for purchase of 300 MW of non-tribal windpower expected to be completed in early 2009. This means that the WAPA economics at current prices can only support the purchase of 50 MW of tribal windpower. Needless to say, this is far less than expected, far less than the 748 projected nameplate capacity by 2010 identified by the 14 participating Tribes, far less than the 1748 MWs that regional Tribes identified for future build out, and only slightly above business as usual.

There remain some unanswered questions in the economics on the purchase of tribal windpower compared to other fuel sources. It was admitted that a baseload of coal fired power as supplemental hydropower is assumed in the economics that will only allow for 50 MW of tribal windpower. Does the study assume a baseload of coal fired power purchase over the ten or twenty year periods? Another related reason for the limited amount of windpower purchase was due to increased costs to WAPA customers. It should be noted that the price of WAPA hydropower allocations have increased three times since 2001, with coal fired power providing the supplemental hydropower.

It should also be noted that drought conditions have existed been endured in the Upper Great Plains Region for nine of the past ten years (1999-2008). Climate scientists and tribal spiritual leaders both expect drought conditions to be the new normal not only in the Great Plains, but throughout the West, which include the 15 states in the WAPA jurisdiction, and nine of the top ten wind states.

What is encouraging about the study is that the limited purchase of 50 MW of tribal windpower is based on <u>today's</u> prices, which include the supplemental purchase of coalpower and the resultant purchase price for hydropower allocations to eligible recipients. It is agreed among the energy and climate communities that the price of coal fired power is only going to increase in the near future. This only makes windpower more competitive and attractive from economic and environmental perspectives. The growing awareness by the American public of the impacts of global warming will soon be reflected in public policy as interpreted by the new presidential administration and the Congress. Intertribal COUP shares this awareness and the anticipated increase in the cost of carbon based fuels to be reflected in the price of electricity.

The Intertribal Council On Utility Policy (COUP) promotes development of tribally owned wind projects and the rethinking of how we operate our federal grid system in the Upper Great Plains Region, which once transmitted 100% hydropower, but now carries nearly 85% coal power. It appears that the utilities that provide supplemental hydropower at higher costs and receive lower cost hydropower have the majority use of the WAPA grid with the dams operating as the peaking power plant. This study intended to determine the feasibility of tribal windpower has determined that only 50 MW of tribal windpower are feasible, as 300 MW of windpower will be provided by non tribal generation. It took 50 years for tribes to receive hydropower allocations in 2001, when the tribes provided the land for the reservoirs and have water rights that produce hydropower. Most of the tribes in the Dakotas have acess to only two markets for windpower: Rural Electric Cooperatives and WAPA.

Now it appears that once again, tribes are the last in line benefit from the federal hydropower system, with only limited purchase of 50 MW of tribal windpower determined as a feasible supplemental power purchase. The same utilities that have had free rein on the integrated federal system are now positioned to provide windpower to supplement the coalpower to firm up the hydropower, a once renewable resource.

Coal is abundant but has a variety of emissions issues and is relatively less dispatchable, given its inability to ramp up and down quickly. Coal, as part of the integrated system has come fully occupy all the excess capacity on the federal grid and has expanded to occupy any additional capacity opened up due to reduced federal hydropower. Coal consumes (actually removes it from the river system) significant amounts of water in the production of steam for its turbines, and in the cooling process. Water limitations, including thermal limits, have already significantly constrained or curtailed conventional generation at times from Wyoming to St. Louis. Coal has been able to externalize significant environmental costs in order to remain the cheapest fuel.

Wind is clean, lacks any emissions and is tremendously abundant in the northern Great Plains, variable but predictable with upwards of a 40% capacity factors on many reservation sites, and Tribal wind enjoys an aspect of "government instrumentality" according to recent FERC rulings. Wind generates electricity without the use or consumption of any water. Wind is expected to carry all ancillary costs associated with shaping and firming.

In the past, Tribes seeking to develop wind power have been told that there is no room on the grid and to make the business case for wind power. Putting the business case issues aside for now, the problem is the lack of room on the grid, when the system by its prevailing rules seems designed to take all the hydropower first and then provide all excess capacity to coal. For supplemental power, the argument has been made that the variability and lack of dispatchability of wind makes it extremely difficult for Western to purchase wind when it needs the supplemental power because you never know when the wind is or is going to be available.

In actual practice, it seems that Coal has both physical and procedural predominance on the grid, and the remaining reduced hydropower is utilized primarily for extremely inexpensive peaking power. Given that arrangement there will never be any room on the grid for significant amounts of windpower.

A conceptual framework for thinking about how we can optimize tribal wind on the federal grid in the mix as a supplement power source for federal hydropower requires us to start with a completely open transmission capacity, of course, recognizing both the primary legal rights of hydropower and the significant reliance upon coal in this region and the existing contractual rights and obligations with regard to the integrated system currently in operation.

However, we need to determine how to make some portion of the grid capacity available to wind. Perhaps we can start with that portion which was once occupied by the federal hydropower, but which has been diminished by the persistent drought moving into nearly a decade. We must also consider the prospects of climate change exacerbating the existing drought conditions and those impacts added on to the changes that may be in the offing for the long-term natural cycle where we move from a "wetter" to a "drier" natural state. In a word, we need to be thinking 30 to 50 years out at least!

We then take all the wind that we have determined the system can handle whenever it is available. The principle of taking the LEAST DISPATCHABLE FIRST!! Then firm that amount of wind (no more than 40%) with most of the existing hydropower, reserving some for final peaking requirements.

Then we add available baseload coal as needed. In the long term scenario, we look to utilize our abundant coal resources in the form of IGCC, along with the remaining hydro reserves, which gives us greater flexibility and ready dispatchability over conventional coal generation.

Intertribal COUP asserts that WAPA, is a treaty partner, as part of the federal government of the United States who approved the treaties with the tribes. The treaties and other Congressional acts support commerce among the Indian Tribes to restore economies in mutually beneficial trade agreements. Never has their been a more fitting opportunity to demonstrate this partnership than by tribes harnessing the power of the wind to supplement the water in the provision of clean electricity for all communities connected to the WAPA transmission system.

With an annual Native wind potential of 535 billion kWhs nationally, Intertribal COUP envisions the build out of thousands of megawatts of tribally-owned, utility-scale wind projects distributed on two dozen Indian Reservations across the Great Plains and interconnected to the federal transmission grid. The integration of tribal wind and federal hydropower can transform the existing system into a clean, green energy dynamo, increasing our renewable energy capacity and supporting sustainable tribal economic development, while keeping coal safely in the ground and reducing the consumption of our precious water resources throughout the West.

Intertribal COUP believes that this study should have included economic methodology that included a scenario which purchases wind at all times, to be supplemented by hydropower, and purchase of coalpower only when the wind is not available and water is in short supply. This can still be done in an extension of this study and under a federal direction to demonstrate the purchase of windpower from an intertribal wind project on each reservation. Intertribal COUP has the plan, the ability, and the finances to complete development of this project within the next year.

Intertribal COUP is hopeful that the new federal energy and climate policies will initiate a new paradigm that supports the primary use of renewable energy, to firm up diminishing hydropower resources, and the purchase of fossil fuels only as the last resort to meet the growing energy needs across the country. The WAPA transmission grid can be restored to be once again the National Renewable Energy Grid, as was its original function in delivering 100% hydropower. It can be the Nation's primary collection system of renewable energy, beginning with Intertribal Windpower in the Northern Plains.

We need our treaty partner to agree to purchase Intertribal windpower and prove that this can be done in the best interest of the United States, the Tribes, and the Earth.

Response to Comments from Intertribal Council on Utility Policy (Intertribal COUP)

Thank you for your comments on the Draft Wind and Hydropower Feasibility Study Report. We believe Intertribal COUP may have misinterpreted several key concepts contained in the WHFS. In particular, comments repeatedly refer to the inclusion of only one Tribal wind energy project in the WHFS Study. The WHFS does make a recommendation for only one demonstration project not to exceed 50MW. However, the study made the assumption that the 300MW of non-Tribal wind energy could be replaced with Tribal or non-Tribal wind energy upon expiration of the 5-year contract term of those contracts - ***please see p. ii third paragraph***. Regardless of "ownership" the WHFS did assess the benefits of distributed wind generation.

Another key misinterpretation by Intertribal COUP is the assumption that coal is "base-loaded" as a Western load serving resource. Western's load obligation is first served by hydropower generation with supplemental energy coming from market purchases of regional resources during those periods when hydrogeneration capability is not sufficient to meet load obligations. While coal is a predominant regional resource in the Upper Great Plains for supplemental needs, it is not the primary energy resource for Western's load obligations. As discussed in the WHFS report and during the Public Comment forum held in Rapid City, South Dakota on January 13, 2009, market purchases of regional resources were never dispatched ahead of hydropower or wind energy in the studied amounts to serve Western load. Rather, market purchases were made only to meet Western load obligations after consuming available hydrogeneration and wind energy as previously described.

In response to your comment at the public meeting in Rapid City on January 13, 2009 and your written comments, a direct correlation between the cost of Interchange (energy) used in the PROMOD analysis and the cost of coal cannot be easily extracted from the analysis conducted for the WHFS. Interchange prices are based on cost of the marginal unit which could be coal or a gas fueled unit. For our analysis, PROMOD did not specify the source of the energy purchased to meet load obligations and the level of study necessary to obtain this type of information would have provided no additional value in the economic analysis conducted for the purpose of the WHFS.. However, in direct response to your question as to the cost of coal, the MRO (US) Coal Average cost in 2011 is $1.29/mmBTU. The corresponding natural gas forecast price for the same year is $8.46/mmBTU. These prices are commodity prices only and exclude additives such as emissions. The data source for the commodity prices is priviledged/confidential information of Ventyx and was not included in the WHFS report.

Several comments suggest that more detailed economic analysis was expected. The level of economic analysis presented in the WHFS report was appropriate given the number of assumptions that had to be made for this study. Lack of site specific information relating to the Tribal wind energy proposals (Questionnaires) received for each of the tribal wind energy projects submitted made it difficult to provide more specific economic details related to those projects. The conceptual interconnection cost estimate used in the study was calculated as a representative cost estimate for all Tribal wind projects studied in the WHFS. Further, the development of the cost of energy estimate was led by Mr. Tom Wind, a well respected wind development consultant currently supporting Tribal wind energy projects for Intertribal COUP. Additionally, the cost of energy estimate was deemed reasonable for the purposes of this study and agreed to by the Project Team. Actual costs could be more or less, depending on site specifics. The production modeling considered a 30 year period as opposed to 10 and 20 years as noted in the comments. ***Costs generated by the PROMOD analysis are available in Appendix H***.

With regards to overall wind interconnection capacity, the primary objective of the WHFS was not to identify overall interconnection capacity but to consider the impacts of the amount of wind deemed appropriate to supply energy to Western in the study analysis. The Dakotas Wind Transmission Study focused on overall wind interconnection capacity and that information was relied upon in this report - ***please see p. 2-28***.

Comments regarding composition of the Federal Transmission system usage or composition percentages do not impact the stated objectives or recommendation of the WHFS. The focus of WHFS was not to assess composition of resource types on the transmission system; rather the purpose of the WHFS was to look at cost/benefit of tribal wind to assist Western in meeting its firm power obligations.

A significant portion of the Intertribal COUP comment letter offered no technical critique to the Draft Wind and Hydropower Feasibility Study Report and therefore the commentary unrelated to the technical analysis conducted is not addressed in this response to comments.

WESTERN AREA POWER ADMINISTRATION

WIND/HYDRO FEASIBILITY STUDY

PUBLIC COMMENT MEETING

Held at Best Western Ramkota Hotel
2111 N. LaCrosse Street
Rapid City, SD 57701

January 13, 2009 at 1:00 p.m.

PRESENT ON BEHALF OF WAPA:

Michael Radecki, Energy Services Specialist
Jody Sundsted, Power Marketing Manager
Doug Hellekson, Contracts and Energy Services Manager
Jay Mill, Information Technology
James Bach, Field Representative
Tracy Thorne, Field Representative
Greg Vaselaar, Field Representative
Kimberly Massey, Stanley Consultants
Rick Hunt, Ventyx

PUBLIC PRESENT:

Don Metzger, Jeff Metzger, Faith Spotted Eagle, Sharon Drapeau, Mike Swenson, Mike Haines, Mike Trykoski, Vic Simmons, John Stone, Jody Zephier, Louis Janis, Vicky Wicks, John DeYoe, Andrea Cook, Qusi Al-Haj, Dwayne Coleman, Fred Mousseaux, Eric Scherr, Chet Mills, Pat Spears, Joe Red Cloud, Lisa Teeslink, Dell Petersen, Bob Gough, Warren Karlen, and Braden Houston

Taken by Sandra C. Semerad, RMR
Court Reporter and Notary Public
Rapid City, South Dakota

MICHAEL RADECKI: My name's Mike Radecki, I'm the Project Manager for the Wind/Hydro Integration Feasibility Study. I'm also the Energy Services Specialist for Western's Upper Great Plains Region.

One, I want to thank everybody for coming out this afternoon. I know there's some weather issues in both North and South Dakota and for anybody that braved the driving conditions, thanks, appreciate it. Your participation in this afternoon's event really makes it all worthwhile.

Some general housekeeping, bathrooms are down at the end of the hall. We'll have a 15-minute break within about an hour. I've got today's presentation broken up into two sections. We'll cover sections 1 through 4 and then we'll take a break and then we'll come back and -- or we'll have some question and answer, some discussion on this morning's events, and then we'll come back and talk about the rest of it.

But today's discussion, Wind/Hydro Integration Feasibility Study -- but before I start I should also point out Mr. Jody Sundsted, our Power Marketing Manager is here with me today, Doug Hellekson, our Contracts and Energy Services Manager, Jim Bach is our Field Representative for the Upper Great Plains Region, as well as Greg Vaselaar and Tracy Thorne. There's Tracy over there.

So today's agenda, I'm going to give you a brief overview of Western, talk about some of Western's historic wind integration activities, then I'll talk about the Wind/Hydro Feasibility Study itself.

We'll cover work elements 1 through 4, we'll have a little discussion, we'll take a short break, when we return we'll talk about work elements 5 through 6, have a little more discussion, and then when we wrap up we'll call it a day.

Western today. Western's Upper Great Plains Region, our office is in Billings, Montana. We have our Rocky Mountain Region, our Colorado River Storage Management Center or CRSP, Desert Southwest Region, and our Sierra Nevada Region.

The Wind and Hydro Integration Feasibility Study applies only to the Upper Great Plains Region as directed by the Energy Policy Act and this study.

Hydro generation facilities in the Upper Great Plains Region, we have two Bureau of Reclamation facilities, Canyon Ferry and Yellowtail in Montana. Yellowtail in particular, the Upper Great Plains Region only gets half of the output from Yellowtail, the remainder goes to the Rocky Mountain Region.

Army Corps of Engineers facilities in Montana is

Fort Peck, North Dakota is Garrison, and South Dakota is Oahe, Big Bend, Fort Randall and Gavins Point.

Western markets approximately 2,000 megawatts of capacity in the Upper Great Plains Region. We have a 378,000 square mile service territory. We've got more than 300 firm power customers consisting of irrigation districts, municipal, rural and industrial users, municipalities, Native American Tribes, public power districts, rural electric cooperatives, as well as state and federal agencies.

Our power is allocated under marketing plans. Our marketing plans are developed through public processes and we follow the requirements of the Energy Planning Management Program, subpart (c), which is the Power Marketing Initiative.

Some of Western's historic wind integration activities. Some of you may have heard of the Dakotas Wind Transmission Study which was completed approximately four years ago. There was a WAPA Wind Integration Study that was sponsored and conducted by the National Renewable Energy Lab and then this study that we're here to talk about today, Section 2606, Wind and Hydropower Integration Feasibility Study, which came out of the Energy Policy Act of 2005.

Talking about the Dakotas Wind Transmission Study, it evaluated available transmission capacities not Western's use of wind. Multiple sites were analyzed in the study, Garrison, Pickert, Leland Olds-Groton Tap, New Underwood, Fort Thompson, White, Mission. Those are all large substations within our service territory.

It also evaluated the impacts of wind on the North Dakota Exchange, Fort Thompson and Watertown interfaces, and what those are are key points in a transmission system moving power across a grid. They could be called bottlenecks. You know, in a lot of studies they are critical elements in determining how much energy can move in and out of the system.

Generally the Dakotas Wind Transmission Study said the system had available transmission capacity for 500 megawatts 95 percent of the time in a non-firm capacity.

Moving on to the WAPA Wind Integration Study sponsored and conducted by NREL, the study objectives were to characterize the Dakotas wind resource, develop wind generation profiles, and assess impacts on the hydroelectric system.

Some of the key conclusions from that study were penetrations of up to 200 megawatts would have quantifiable but modest impacts on the characteristics of control area demand. At the 500-megawatt penetration level they became noticeably larger, and then at 1,000 megawatts they were further amplified. The study did not provide an assessment of control area operations or how generation sources would be impacted.

Moving on to today's topic, 2606 Wind/Hydro Feasibility Study, the key objective from the legislation was to study the cost and feasibility of developing a demonstration project that utilizes wind energy generated on Tribal lands with the hydropower generated by the Army Corps dams in the Upper Missouri Basin to supply firming power to Western.

Boiled down there are three main components of the study: There's physical integration, that's actually putting wind facilities in the system. There's operational integration, that is how does the operation of that wind plant work with the existing system. And then there are the resulting economics, how does it all work out with regard to dollars and cents.

Keynote, the results and findings. The results reflect the assumptions used in this study. As I go through today's presentation I'll mention several different things, assumptions we made, conditions we assumed, they are key in the findings and the conclusions made on this study.

Some of our initial activities, formation of the project team. In March of 2007 we sent out an invitation to all Tribal and non-Tribal customers in the Upper Great Plains Region. In May of 2007 a project team was formed and this was our core project team. Tribal participants included the Blackfeet Tribe, Fort Peck Tribes, the Santee Sioux Tribe, as well as the Intertribal Council on Utility Policy.

Some of our non-Tribal members included Rushmore Electric, Heartland Consumers Power District, the Nebraska Public Power District, as well as federal participants including the Bureau of Reclamation, National Renewable Energy Lab, and the Army Corps of Engineers.

In May of 2007 we awarded the contract to Stanley Consultants. They were our prime contractor for this project.

The wind/hydro work plan consists of six primary work elements. Work element 1 was develop the work plan. Work element 2 was analysis of historic operations. Work element 3, wind project identification. Work element 4, transmission system evaluation. Work element 5, assessment of impacts, also economics. And then work element 6, the draft and final report.

Work plan development was a collaborative effort of the project team members. We met in person as well as through conference calls. We refined the project scope based on legislation. We identified key study requirements and worked through the development of the work plan as well as continued to work together through the study.

On September 27th of 2007 we had a public meeting in Bismarck, North Dakota, where we accepted public comments on the work plan. That was also available for public review and comment.

November 5th of 2007 the work plan was finalized and we began to study in earnest.

The first real work element of real key work was work element 2, the analysis of historical operations. Essentially, the historical operations analysis was look in the past, what has Western had to do with regards to purchase power, how was the runoff into the river system, what our hydropower generation was, what our purchase requirements were.

In conducting this activity we looked at some single week snapshots of generation and load. I'm going to show you a couple here today for 1997, which is our high water/generation year, 2000 was an average water/generation year, and 2005, which was our low water/generation year. Now, subsequent to this study, as the study was well under way, 2007 actually was an even lower year, but 2005 suits us well for this study.

I just want to point out a couple things. The bars represent annual runoff above Sioux City and this is from 1968 to 2007. The line above the bars is the hydropower generation.

A couple things that I want to point out about this is that hydropower generation and runoff don't have a one-to-one relationship. We may have good runoff one year, but our generation could be less than a year in which we had less runoff. I want to point out 1993, hydropower generation was just a little bit below 6 billion kilowatt hours, but when you look at the runoff it was significantly more. Well, that's because of the way the Army Corps of Engineers operates the river system. They were in a mode of trying to rebuild the reservoirs.

And as you look through the history you'll see other similar occurrences. You can look where 1997, which was our high water/generation year, which was a record year for water, and then the next year we had significantly less runoff but we still had pretty good hydropower generation. So we just want you to get into your mind or help you understand that there's not a one-to-one relationship between runoff and hydro generation.

This and the next two slides are single week snapshots. These are an hourly profile from each of the three years I discussed, 1997, 2000, and 2005. The year that I have up on the screen right now is 1997, which represents our high water year. The blue is our generation, hydro generation to meet our loads. And hopefully you can make it out, there's a black line in between the blue and the red crosshatch. That is the corresponding load that we had to meet. And then above that is excess generation. That's excess generation that was available for sale. Again, 1997 was a great generation year.

The next slide is 2000, it's our average water year. Now you see something a little different, you see yellow pop up into the screen. The blue, again, is our hydro generation. That same black line, our load, but you'll note that the hydro generation didn't meet our load requirements so the yellow represents purchase power. In 2000 we still did have some excess hydro generation that was available for sale.

And then we move to 2005, approximately the same week for all three years, but a completely different story. 2005 was an extremely low runoff and generation year and you can see that this week, in particular, but for most of the year Western was on the market purchasing power to meet our load obligations. There were some periods of excess generation in 2005, but in comparison to a normal year or a better water year, relatively minor.

One of the next things that we had to understand in our historical operations is Western's load, what is our load pattern. This represents the total monthly load for the same three periods, '97, 2000, 2005, and if you look at this you say, well, it's consistent, but there's some difference.

Well, there were some differences and, you know, quite honestly, if you look at March of 2000, as well as December and a little bit in July and August, there would appear to be a few anomalies, and when looking at the data we couldn't really determine the cause of the anomalies, but this graph still depicts our key assumption and, that is, our load is consistent.

One of the other reasons our load is consistent is because we only market 2,000 megawatts. We have a firm power obligation. We are not a full-service provider. That is, we don't -- we're not required to follow someone's load. We provide energy up to a limit, whatever their allocated limit is.

This and the next two slides, I'm going to try to take this and show it to you in another format. Looking at 2000, our average water year, the blue represents our hydro generation. Hopefully everybody can see that. What I brought up on the screen now is our total load. And by the way, this is -- these are hourly profiles of generation and load and you can see when you overlay the load over the generation there are periods where the generation exceeds the load and periods where the load exceeds the generation.

Now I'm going to bring in the difference between load and generation, and what I'd like to point out now is, all of the yellow above the zero line indicates the requirement for Western to purchase energy to meet our load obligations. All the yellow below the zero line is excess generation and resulted in our ability to sell excess energy.

Our historical operations findings. Our goal was to identify a range or bandwidth for the capacity to offset historical purchases. Some of the key elements we considered was the range of hydro generation scenarios. We talked about 1997 being a good generation scenario, 2000 being an average, 2005 being below average. We talked about Western's consistent load patterns as well as ultimately our ability to use energy. Western's goal is to remain a net user of energy with regards to meeting our load obligations.

Based on the study that we conducted the initial integration range was 0 to 330 megawatts. Now, I want to point out that this does not represent wind nameplate capacity, it was 0 to 330 megawatts of capacity.

Moving on to work element 3, wind project identification. Western received nominations or information from 14 reservations as well as one intertribal organization, and ICOUP, Intertribal COUP, actually represented eight different reservations in their submittal to us. All in all there are 18 projects throughout the Upper Great Plains Region. Project size envisioned was between 10 and 320 megawatts. The stage of development of projects included everything from, hey, we'd really like to have a wind project on our reservation to several reservations who were well down the road in project development, they had conducted studies, they had wind anemometers installed, they've got consultants on board working towards project construction.

The project team in one of its earlier activities developed a questionnaire to collect information from the Tribes about their wind development activities. Based on the questionnaires that we received for this project -- you know, again, projects ranged from conceptual through various stages of development -- an initial development potential was approximately 748 megawatts by 2011. Post 2011 development was approximately 1748 megawatts. Project development on reservations not included in this study was assumed to be an additional 50 megawatts each, or 50 megawatts at each location. All in all, total resource potential is at least 2600 megawatts, probably much more than that.

One of the next activities that we had to perform were to conduct Tribal wind energy profiles. Wind energy profiles were developed for each wind project that we received information on by the established deadline. Wind production modeling was necessary to evaluate our transmission system impacts, operational impacts, and to help us in the economic analysis.

The wind modeling was conducted by 3TIER. They're an established company in wind development, wind modeling, wind forecasting.

For this project we used one turbine type. Several of the questionnaires that we received indicated they may use -- may have wanted to use other types of turbines, but for the purposes of this study and to try to keep everyone on a level playing field we chose the GE 1.5 megawatt SLE wind turbine, and the reason we wanted to choose only one turbine was because of the power curves. It greatly simplified the analysis that we would have to conduct for the study.

The wind modeling, we produced hourly average wind speeds as well as resulting energy profiles.

Tribal wind potential findings. I think everyone in here probably knows Tribal lands are located on good wind resources or within a good wind resource. For Western, for the purposes of this study, what we found was that there is a good resource pool from which a demonstration project could be competitively awarded if approved and authorized or funded by Congress.

Work element 4, the transmission system evaluation. The approach that we had taken was to model the east system and the western system separately. I guess I didn't think that I probably -- does everyone understand that the Upper Great Plains Region has two systems, the eastern grid and the western grid? Has anyone heard of the Rapid City DC tie? Okay. A couple folks.

Okay. Without getting into a lot of detail, while Western covers -- our Upper Great Plains Region covers Montana, Dakotas, Minnesota, Iowa, Nebraska, the systems are actually physically separated by the DC tie. In other words, they basically operate independently, and I'm not going to get into -- I can't give you a good explanation as to all the electronic reasons or the electrical engineering reasons behind that, but there's a good reason and I can get you an answer if you need to know it.

So for the purposes of this study we modeled the east and west grids separately because they do operate independently.

The modeling followed established reliability criteria and protocol using approved model cases. We also developed conceptual interconnection costs and we assumed that interconnection would be at 115, 161 or 345 kV.

There was a critical assumption made in the transmission system analysis and, that is, there are other system improvements underway/ongoing for projects that have no relation to this study and they are in the model cases, so the assumption that we had to make to move forward was that anything in the model that was being looked at, any improvements that were associated with the particular project that was being looked at, those improvements were put into place. So a key assumption was that for everything in the model, any improvements of the system that were required, they were put in place in connection with whatever was being studied.

Transmission system analysis findings. In the east system we injected a representative 50-megawatt project into the transmission system. The contingency analysis basically is, if we put this in, what's going to happen to the system? A couple of the key things that they're concerned about are overloads on both the lines and the transformers.

For lines there was one less overload over the base case and for transformers there was one additional overload over the base case. For voltages, they're concerned about whatever you're putting into the system, what does it do to the system voltage. For undervoltages there were three additional undervoltages over the base case, and overvoltages there were no changes.

For the west system we actually injected two projects totalling 89 megawatts. The reason we injected two projects into the west system as opposed to one project in the east system is that we only had two potential nomination sites in the west system, so we put both of them in.

So basically the same thing, we conducted a contingency analysis. For overloads for lines there was one additional overload over the base case. For transformers there was no change. For voltages there were ten fewer undervoltages over the base case and there were no overvoltages or no changes to overvoltages over the base case.

Transmission system interface analysis findings. Both the east and the west case analysis revealed no interface ratings were exceeded as a result of Tribal wind injection. Any projects selected as a demonstration project is still going to be subject to Western's Open Access Transmission Tariff or OATT process and it's going to require a formal feasibility study, system impact study prior to actual interconnection and transmission service.

Transmission system analysis conclusions. The injection of the Tribal wind in the amounts studied did not result in a requirement for overall grid additions. We assumed that base case system violations were going to be resolved relevant to the other interconnection requests and the conceptual interconnection cost that was developed for this study of $8.3 million, it consisted of a typical configuration of interconnection facilities at 115 kV and it assumed no additional transmission or grid additions.

So that's the first half of this afternoon's discussion or this afternoon's presentation, so I guess what I'd like to do is open up for some brief discussion relevant to what we covered this morning. I'll try to answer any questions. If there's something I can't answer this afternoon, we do have -- I should have mentioned earlier, I apologize, we do have a reporter here, a recorder recording today's discussion, and there are reporters here, so we'll get your question and we will follow up with you on something that we can't answer this afternoon.

So any questions on what I've covered so far this afternoon?

LOUIS JANIS: I do.

MICHAEL RADECKI: Could you please state your name?

LOUIS JANIS: My name is Louis Janis, I'm with the Oglala Sioux Tribe, and we're really going to develop an energy company with the Tribe and we're almost into the new administration now and I seen your comments being wanted by the 13th. That's today, right, the written?

MICHAEL RADECKI: No, Sir, that's February 13th.

LOUIS JANIS: Oh, that's February 13th. Okay. Because I know I'm pretty sure some of our economic development council members would like to comment on your marketing.

The question I had was, you know, there is maybe three or four WAPA lines going through Crow Creek and I just wondered why nothing hadn't been developed in that area. I know we drastically want something like that, but, you know, it extends eight miles off our reservation and the comment that came up is the political boundaries. Is there a process that Western can do to alleviate that process?

MICHAEL RADECKI: I'm trying to -- is it your thought that we didn't include your Tribe in the study for some particular reason?

LOUIS JANIS: No, it's just that if you look, the lines go right through -- right through Crow Creek. It must be three or four lines and, you know, it seems -- that was one of the reservations that felt -- I felt is really, you know, hurt by today's economics and, you know, technologywise, you know, and it seems like, you know, why haven't they pursued renewable energy?

I know Rosebud and Pine Ridge are ahead of the game, as well as Cheyenne River. We would gladly accept something like that, you know, on our reservation. Just even the comment that came out was it was very political by the corporations, the energy corporations running their lines through there and as to why -- you know, why any transmission hookup link or firming link could have been developed for -- you know, this has been going on since 1992 and here we are, almost 10, 20 years later, you know, and we're still asking the same questions and you guys seem to -- should have been up on that technology, yet we're still at that same -- maybe advanced two or three pages down the road, that's it, so -- but that's my question.

MICHAEL RADECKI: Okay. Just quickly, the objective of the 2606 study, the study I'm presenting on this afternoon, was to study the cost and feasibility of a demonstration project and this study will make a recommendation to Congress for a demonstration project. How that project will be selected or implemented has not yet been determined, so I think in partial response to your question, the Crow Creek Tribe stands, I believe, as equal opportunity as any other Tribe in the region to be selected as a demonstration site. So there have been no decisions made specifically with regards to how a demonstration project will be identified or selected, if it's approved and funded by Congress.

LOUIS JANIS: Because I know, like, for us the transmission -- I just wondered how far they got on the -- there was a gentleman out of Seattle, Washington, did a study on using the rail line as the transmission, that forms the transmission line, and I've seen -- I've seen a billion dollar project developed on a monorail system in, like, Walt Disney in Florida. You know, why can't something like that happen to Rosebud and Pine Ridge to Rapid City? You know, there's been -- I know the Black Hills issue's still going through legislation in Congress, you know, and that's -- what's $1 billion to that, you know, to develop something like that as a transmission line?

MICHAEL RADECKI: I believe the gentleman in the back had his hand up, and could you state your name, please?

JOHN STONE: Are you done, Louis?

LOUIS JANIS: Yes.

JOHN STONE: John Stone of the Yankton Sioux Tribe. You was talking about transmission capacity and I don't know if this is relevant right at this moment, but the saturation study, how far has that moved on or has that been awarded or where is that sitting at to determine saturation, South Dakota wind power?

MICHAEL RADECKI: Unless I know it by a different name, I'm not familiar with that study.

JOHN STONE: It's in the study that you guys referenced in your document, your draft study document. There was to be a --

MICHAEL RADECKI: Oh, are you referring to the economic saturation point?

JOHN STONE: Yeah, the saturation of South Dakota capacity.

MICHAEL RADECKI: That will be study work to be performed.

JOHN STONE: Okay.

MICHAEL RADECKI: Okay. Sir?

MIKE HAINES: Mike Haines with Fox Ridge. My question in your study is, what's your time frame of implementing a 50-megawatt, integrated with water to firm it, and then that turnaround time before that's going to turn back to being able to develop wind and use Missouri River water as a firming agent with the wind? And I'm sure that must have been their thoughts when they implemented the entire study. Has there been any time frame put on that?

MICHAEL RADECKI: No, there haven't been any time frames established for that. For the purposes of our study we looked at -- and I apologize, I should have discussed this earlier. The year 2011 was chosen as our study year. When we started this project we had to figure -- or we had to assume how long was it going to take us to complete the study and when would we get a report to Congress, when could Congress act on something and fund it. So our assumption was that a project, a demonstration project could theoretically be built and put in place by 2011.

MIKE HAINES: Then is a private wind farm eligible for this 50 megs also or is it a government entity only?

MICHAEL RADECKI: The 2606 study is specific to Title V of the Energy Policy Act, which is Indian energy, and it is specific to Tribal lands and Tribal projects.

MIKE HAINES: Okay.

MICHAEL RADECKI: Does that answer your question?

MIKE HAINES: Yeah, it sure does.

MICHAEL RADECKI: Any other questions?

QUSI AL-HAJ: Does any of the states that -- I'm sorry. My name is Qusi Al-Haj, I work for Senator John Thune. Does any of the states you're looking at for potential sites have more advantage than others as far as wind and being able to utilize -- I mean, as far as does the wind blow more in South Dakota than it does in Montana or North Dakota?

MICHAEL RADECKI: I don't believe that based on anything that we found any one of the projects that we looked at has a specific advantage over another, and when a project is actually approved, authorized and funded, I'm sure that we will probably have to develop some criteria to determine how a project will be selected. That may be a criteria. I don't know. That's essentially work to be completed once we know whether or not we're going to have a project.

JOHN STONE: John Stone again. Could you elaborate a little on what you foresee as being the process to determine the pilot project?

MICHAEL RADECKI: I would hate to look into a crystal ball right now. I have maintained throughout this project, through this study that it would more than likely be something competitively awarded amongst the eligible Tribes, and eligible Tribes, that would be all the Tribes in our region.

JOHN STONE: That are federally recognized?

MICHAEL RADECKI: Yes. You know, once it gets to Congress and what they decide, it's in their hands, but that has been our assumption all along.

Any other questions?

FAITH SPOTTED EAGLE: My name is Faith Spotted Eagle, Yankton Sioux Tribe. What are some steps that Tribes could take to prepare to present themself in this competitive process?

MICHAEL RADECKI: You know, I'd hate to say -- I'd hate to try to give you guidance on preparing for a competition that I have no idea what it's going to include, but the most sage advice that I could give you is understand wind financing, understand wind project development. Talk to a consultant. Talk to Intertribal

COUP. Both Pat and Bob are very knowledgeable and could lead you to someone else to help educate you on what it takes to develop a project and put one in place.

JOHN STONE: Does the DOI have any involvement in this process, particularly the guys out in Lakewood, Colorado that deal with energy production? Would they be involved in the process of coming up with the application or the technical assistance or --

MICHAEL RADECKI: That has not been determined. Have they been involved? I can answer that a little bit. I did speak with -- and you're referring to the DOI Minerals Management?

JOHN STONE: Yeah.

MICHAEL RADECKI: I have spoken with them several times over the last few years. I know they're aware of our project. They've been trying to keep up to speed on what's going on, but as to what their future involvement will be, I don't know at this point in time.

Any other questions?

(No response.)

MICHAEL RADECKI: Okay. I've got 1:40. I suggest we take a 15-minute break, but before we do, do we know where the sign-in sheet is? I'll have a sign-up sheet up here in the corner. If you didn't sign in, please do, and with that we're going to go ahead and take

15 minutes.

(A break was taken from 1:44 p.m. to 2:01 p.m.)

MICHAEL RADECKI: Okay. Well, it doesn't look like we lost too many. That's good. I didn't scare anybody off.

Okay. Next slide. Moving on to work element 5, assessment of impacts, and for anybody who thought the first half of the presentation was really clear and easy to understand, hold on.

The assessment of impacts was conducted using a series of power marketing simulations using PROMOD IV simulation software. It's a computer model. We conducted a zonal analysis to identify the long-term 30-year economics of the integration of Tribal wind energy as well as a nodal analysis to evaluate how Tribal wind impacts overall system operations and transmission constraints.

To do this we had to develop some case scenarios. There was a reference case, which is 158 megawatts of existing wind of which none of that wind serves Western load.

There's a base case of 723 megawatts. That's the existing wind plus non-Tribal wind projects reasonably expected or assumed to be connected to the integrated system by our study year 2011. The 723 consists of 158, 265 megawatts of non-Tribal projects that are committed, that had studies either under way or completed, as well as 300 megawatts of wind that would result from a midterm purchase to meet Western load obligations.

And then last is the Tribal case, which is the 723 that I just discussed plus a 50-megawatt demonstration project.

The case design compared those to three hydro generation system loads. I talked about those earlier, the low, average and high water years. We looked at a no wind scenario, the two wind scenarios, which was the reference and the base and Tribal wind scenarios, and we looked at Western's load obligations.

Remember earlier I stated that our load is not subject to growth? Our load patterns show general consistency over time.

PROMOD, the power market simulation used, the software itself has standard input assumptions for most data. It uses hydro generation forecasts for zonal, it was a 30-year average. For nodal it was a single year average. Peaking contract energy returns, 30-year load and wind forecasts. We talked about our load being consistent. The wind forecasts, you may recall that I referenced 3TIER developing wind generation profiles for us. Reserve requirements for wind penetration levels.

We injected a cost of energy as well as considered carbon legislation penalties that may be in place.

Our forecast development, we utilized 40 years of hydro system operational data. In fact, I think it was the first graph that I showed you was that 40 years of data.

For our low hydro scenario it was 7.8 billion kilowatt hours. And one thing you need to understand about the low hydro scenarios and the high hydro scenarios, this is assuming 30 years of low hydro. The high hydro assumes 30 years of high hydro conditions. So to represent that we used data from 1998 to 2007 and we used 10 year's worth of data repeated three times.

For the base hydro or average conditions, 10.2 billion kilowatt hours, we used 1967 to 1996, 30 years of data. And then for our high hydro conditions, 12.06 billion kilowatt hours, 1967 to 1976 repeated three times.

For our nodal single year forecast we used Army Corps of Engineers' projections through 2011. That is the Corps' actual projections that they use in developing their annual operating plans as well as the daily operating orders that they issue to the dams.

For low hydro we selected year 2007 with 5.7 billion kilowatt hours. Our base hydro year was

2000 with 10.2 billion kilowatt hours, and 1997 with 15.2 billion kilowatt hours.

30-year load and wind forecasts, we had to develop a representative load/wind year utilizing Western historical load data, wind data from Western's data archive, and 3TIER simulated wind energy matched for the year 2000.

Forecasts were based on the two wind cases previously described and forecasts are a representative profile and not intended to be used as a metric for wind energy potential in the region.

Something that I probably should have mentioned earlier when I talked about the profiles conducted on the Tribal projects, in establishing or setting up the wind modeling with 3TIER we did not optimize turbine locations on any of the reservations, so the information that was developed may not represent the best conditions at any one spot.

Reserve requirements. Wind penetration levels assumed for the study, 723 megawatts as well as the 773 megawatts, represent penetration levels of 23 and 25 percent of Western's control area or our balancing area.

A sub-hourly analysis was conducted to determine the additional load following requirements for the reference wind case, the base case, and the Tribal wind case.

The sub-hourly analysis findings. The three wind cases, reference, base and Tribal, under three different conditions. There is a controlled performance standard that our -- that the system operators have to maintain; that is, generation to load.

In this metric Western's Upper Great Plains Region maintains approximately a 99 percent CPS2 standard, which is extremely high nationwide. Western's pretty proud of it. But under this scenario maintaining a 98 percent CPS2 standard in a perfect wind forecast; that is, you know what the wind's going to be for the next hour, for the reference case the existing wind 18.5 megawatts of additional load following requirements, for the base wind, 28 megawatts, and then you add the additional 50, it's 29.4 megawatts.

The next scenario is a 98 percent CPS2 standard with a forecast error. That's an imperfect forecast. You don't know exactly what it's going to be, but you base the forecast on what it did the previous hour. For the reference wind case it's approximately the same, 18 and a half megawatts, but for the base wind case it increases to 73.5 megawatts, and for Tribal wind it increases to 77.2 megawatts.

The project team said, well, what if we reduce the CPS2 metric to 95 percent? You don't have to meet 98 percent, what happens when you go down do 95? Essentially no change to the reference case. The base wind dropped back down to 42 megawatts and Tribal wind dropped down to 45.2 megawatts.

So adding 50 megawatts to the existing -- or to the base wind case of 723 megawatts had an impact of 1.4 megawatts under 98 percent CPS2 metric with the perfect forecast, 3.7 megawatts with an imperfect forecast, and 3.2 megawatts with a 95 percent CPS2 metric with an imperfect forecast.

One of the questions probably in your mind is, why is the reference wind case 18.5 across the board? And we had a bit of discussion with the gentleman who did the sub-hourly analysis for us and it predominantly deals with the small amount of wind in the system, its distribution within the system, and the fact that it had a relatively negligible impact under each of the three conditions that we looked at. There was some deviation between these numbers, but it was rounded out when we reduced it down to just one digit out.

The cost of energy for a Tribal wind project. To conduct the economic analysis we had to develop a cost of energy. This particular activity took place over a course of conference calls with the project team, and, in fact, one of the Tribal consultants on the project team led a significant amount of the discussion on this topic.

We utilized two different industry-accepted wind project calculators. We produced two estimates using each calculator, one with a production tax credit and one without. The estimate was completed using assumptions agreed to by the project team, in particular, assumptions agreed to by the Tribal representatives participating in the call.

An energy cost estimate of 5 cents per kilowatt hour was used, and that's in 2011. It includes the production tax credit. It does not include the value of REC, and it also includes the cost of the transmission interconnection.

The market simulation results. The nodal results for the base and Tribal wind cases as compared to the reference wind cases, no additional constraints on the flowgates -- and we're talking about transmission now -- no significant increase in the number of binding hours, nor was there a significant increase in wind curtailment due to transmission.

The economic analysis. Specifically the net cost to Western from zonal results, the 30-year simulations were discounted 5 percent in the net present value. The REC values were included, the $5 initial value, 5 percent escalation. Transmission O&M costs were included and the O&M costs were assumed to be 10 percent of the capital cost with a 4 percent escalation.

Okay. Here's where it starts getting interesting. This is the 30-year net present value results. So the reference case, which is 158 megawatts of wind on the system today of which nothing serves Western, okay? The base wind is 723 megawatts in the system, 300 megawatts serves Western. Tribal wind, 350 megawatts serves Western. So that's 300 from the base case, 50 from the Tribal case.

Under a low hydro scenario the 30-year net present value cost is $6.093 billion. That's the 30-year cost for Western to buy energy under this scenario to meet our firm power obligations. Under the base wind scenario with 300 megawatts to meet Western's load the cost decreased to $5.983 billion. Under the Tribal scenario they decreased further to $5.981 billion.

Base hydro case and high hydro case, all the same ground rules apply. The cost to Western under the base hydro condition, 4.631 billion over 30 years. 300 megawatts serving Western load, 4.589 billion. 350 megawatts, 4.601 billion over 30 years.

Under the high hydro scenario, remember that's 30 years of high hydro conditions, cost to Western, 3.475 billion. With 300 megawatts of wind serving Western load, 3.496 billion. With 350 megawatts serving Western load, 3.521 billion.

So the costs actually increased under the high hydro scenario with wind. And I'm going to show you this all in a different format here in a couple slides. But we're not looking at the cost of wind compared to the cost of hydro. What we're looking at is the cost of wind with regards to other sources of purchased energy.

One of the next things we had to do, though, was looking at a comparison of the reference to the base case and the reference to the Tribal case. So this is the differences between the whole -- or the net present value numbers we just discussed. Under the low hydro scenario the base wind case, that's 300 megawatts, saves $110 million over 30 years. The Tribal wind case saves $112 million over 30 years.

Under our base hydro conditions base wind saves 41 million over 30 years, Tribal saves 29 million over 30 years.

Under high hydro conditions base wind costs 21 over 30 years, 21 million over 30 years, Tribal wind costs 45 million over 30 years.

Comparison of base wind to Tribal wind, that's what's the difference just between base and Tribal, or that is what is the cost associated with adding that 50 megawatts.

Under the low hydro scenario Tribal wind saves 1.1 million over the base case for 30 years.

Under the base hydro scenario Tribal wind costs 11.9 million more over 30 years.

Under a high hydro scenario Tribal wind costs 24.6 million more over 30 years, and those are costs over the base case, and I want to show you that again yet in another format.

So the last two slides that I just went over, which is the difference between the reference case and the base case and the reference case and the Tribal case, both produce savings to Western under the low hydro scenario and the base hydro scenario, both add additional costs in a high hydro scenario.

Under a low hydro scenario that 50 megawatts saves an additional 1.1 million. Under the base hydro scenario, or average water year, it costs an additional 11.9 million, and under high hydro conditions -- I want to back up. Under the base hydro scenario it saves 11.9 million less. The point is, it's still saving Western money overall, it just saves 11.9 million less than the 300-megawatt scenario. And under the high hydro scenario the 50 megawatts costs an additional 24.6 million over the 300-megawatt scenario.

Did I confuse anyone? I didn't have a question slide in here right now, but this slide is important, and if you take anything away from today's presentation, I want you to be clear on this slide.

Okay. A couple slides back I mentioned that we looked at the impact of carbon legislation, so we ran an additional set of cases that excluded a carbon penalty. We ran base hydro/base wind, base hydro/tribal wind. The results were somewhat counterintuitive.

The no carbon penalty market resulted in increased costs of approximately 1.2 billion over 30 years. The reasons simply boil down to a change in the cost curves for energy production in the region.

Under a no carbon penalty market Western saw a decrease in sales revenues; that is, that clean hydropower was a little less valuable and it's a little less valuable because of an increase in coal generation in a no hydro scenario and changes in the cost curves for other than intermediate generation facilities. In other words, in a no carbon market coal is base loaded and when Western needs to buy power, peak power for power to meet our firm power obligations, we're generally buying it from the more expensive units that are on line.

Rick didn't throw anything at me so I did good.

Impact on reservoir fluctuation. Overall hydroelectric operations are governed by the Missouri River Mainstem Reservoir System Master Water Control Manual. Annual operations follow an annual operating plan that's developed each year by the Army Corps of Engineers. That annual operating plan is also updated in the spring of each year and in implementing the annual operating plan every year the Corps issues either standing orders or daily orders which dictate the generation at each of its dams.

Reservoir system uses. Hydroelectric generation is a by-product of other system purposes, flood control, beneficial consumptive use, downstream water supply, navigation, recreation, wildlife. The need to move water for other purposes is the driving factor behind hydroelectric production.

The addition of wind is not expected to change long-term reservoir management practices. Wind may have short-term impacts on real-time operations and could affect scheduling over several days.

The addition of wind is not expected to provide additional flexibility in management of the system. One thing that I want to point out is that Western has, the Corps has, we have and actually make use of the existing flexibility in our daily operating orders, and the slide that I showed you earlier I'll just take you back to quickly.

These points right here represent the peak loads in a given day; that is, when the most amount of energy is needed in a given day. So if you look at our hydroelectric production, these low points represent the off-peak periods, essentially nighttime. So Western, the Corps flex the generation capacity of the system to extract the most benefit from it, so there is flexibility in the system and it is used.

Key conclusions. The economic simulations indicate the calculated capacity range of 0 to 330 megawatts doesn't identify the theoretical optimal level of cost savings to Western's customers. That was that number we came up after work element 2, the historical analysis.

We also learned that carbon legislation plays a significant role in the economics of wind and hydropower integration.

Our recommendations. A demonstration project, if authorized and funded, be of no more than 50 megawatts nameplate in size. Any costs of a demonstration project beyond what Western would have normally paid for like energy shouldn't be borne by Western's ratepayers and additional study is required to refine the economic saturation point for wind to serve Western's load, including impacts of carbon legislation penalties as that develops.

Some of the benefits of a demonstration project. It provides an opportunity to develop and test standards and terms for mutually beneficial federal/tribal/customer partnerships, and it will provide long-term benefits from a source of renewable energy, it will mitigate a portion of the uncertainty of future energy costs, produce economic benefits of renewable energy development on Tribal lands, and enhance energy security through reduction of dependency on fossil fuels.

Some of the next steps. A question was asked earlier about getting comments in. Public comment period closes February 13th. We expect our response to comments will be approximately two to four weeks after the close of the comment period depending on the number of comments that we receive.

Western will prepare a final report to Congress and that will make its way up through the Department of Energy for submission to Congress. We expect to submit a final report in May of this year.

Submission of written comments. Submit written comments to Mr. Robert Harris, he's our Regional Manager. This is the same information that you found in the Federal Register notice that's available actually on-line at our project website. Comments can also be submitted via E-mail, UGPWindHydroFS@wapa.gov. These addresses are in your handouts, also is the Wind/Hydro Study web address. If you haven't seen the document it can be found at this website location.

Questions, comments relevant to part 2? Yes?

JOHN STONE: John Stone, Yankton Sioux Tribe. Did the Corps of Engineers comment on the probability of low base or high, or did you guys look into their documentation as to predict some sort of a 30-year forecast of which one of these it would most prominently be in?

MICHAEL RADECKI: Oh, you mean which one of those would be -- is most expected to happen?

JOHN STONE: Yeah.

MICHAEL RADECKI: No, that wasn't our purpose.

JOHN STONE: Okay. I see there's -- it ends up -- in a high hydro production year it ends up costing WAPA to have wind power integrated, Tribal wind power. How about the feasibility of marketing that power through the transmission grid at some point when it's not feasible for WAPA to be buying it to at least allow the Tribal wind to be passed through their grid?

MICHAEL RADECKI: The PROMOD IV software, the economic analysis, as part of running that analysis it actually sells that energy and the results of the software doing that, we still lost money. It still cost us more money.

JOHN STONE: The program considered it, then?

MICHAEL RADECKI: The program sold the energy. It didn't just vanish. It assumes that all energy we did not need to meet load was sold on the market.

JOHN STONE: Okay. Then to the reservoir, the impact of wind on reservoir fluctuation. In a case such as Fort Randall where WAPA is peaking power for six hours a day and then shutting it off for the remainder, the ability for wind to capacitate that peaking would actually enable the Tribe to stop the degradation of our bank system, so actually it would impact, in just my general view of it, the fluctuation of the flow that WAPA is using at the Fort Randall Dam.

When they're peaking at Fort Randall they're opening the generators up wide open for six hours and shutting them off for the remainder of the day, which leads to further bank degradation, and that's where I'm thinking that would it be possible to determine that on a case by case basis of whether or not it would be in making these projects more appealing, I guess.

MICHAEL RADECKI: I don't know if I can really answer that question. One, I'd ask just to make sure that your question is submitted. I know we do have it.

JOHN STONE: I just raise that because of participation in the operating manual process, in the master manual, I see their ability to stop the peaking, I guess, which I'm really not for.

MICHAEL RADECKI: Yeah, and I believe, if I can kind of summarize your question a little bit, your question is addressing two things: One, it's addressing flexibility of the system, can we change how we peak because of an impact that it's having on --

JOHN STONE: Basically I would like to see the river run steady and you peak off of your wind power. That sort of scenario is what I'm looking for.

MICHAEL RADECKI: Yeah, and I believe the issue there would be, it would be based on what the availability of wind is, and being an intermittent resource the likelihood isn't very good, but we'll give you a better answer to your question.

JOHN STONE: Okay. I think that's all I had. Thank you.

MICHAEL RADECKI: Other questions, comments? Did I just totally confuse everyone?

(No response.)

MICHAEL RADECKI: Again, my goal here today was to walk you through the report, help you understand the key components in the report and really try to help you answer any questions you might have as you go back and either finish your comments or develop your comments. We want to try to help you provide meaningful comments as you submit them to us.

JOHN STONE: One more question I would have. In our proposal, I guess, or whenever that time would come to apply for the pilot project, would WAPA consider that an added benefit if it serves more than the purpose of just the integration? Such as if we could prove that it would actually eliminate some of the peaking and the bank degradation on the Yankton Reservation, would that be a consideration?

MICHAEL RADECKI: I can see where that might be a consideration, but, you know, as I said earlier, we don't know how that selection process is going to be put together and what it's going to consist of.

JOHN STONE: I was just mentioning it because it was included and mentioned in the study as something to look at, so, you know, they must have had a purpose for asking the question does it --

MICHAEL RADECKI: Right.

JOHN STONE: -- you know, fluctuate or does it have an impact on the reservoirs, you know, so Congress must have asked a question, so they -- you know, they had a reason for that. That's kind of why I was putting it forth.

MICHAEL RADECKI: Okay.

JOHN STONE: Thank you.

MICHAEL RADECKI: Any other questions or comments? Pat?

PAT SPEARS: Yeah, this may be going --

MICHAEL RADECKI: Pat, could you state your --

PAT SPEARS: Oh, excuse me. Pat Spears, Intertribal Council on Utility Policy. The slide that you want everybody to understand, going back there, maybe it would help if you put that up.

MICHAEL RADECKI: That one?

PAT SPEARS: Yeah. But we're comparing the cost benefit and savings of wind energy over this 30-year period, we're comparing the wind energy to the cost of fossil fuel that you normally purchase for supplemental hydropower.

MICHAEL RADECKI: Correct.

PAT SPEARS: And you've got, you know -- I mean, the low hydro years is based on a 10-year period and a high hydro you do on a 10-year period. I --

MICHAEL RADECKI: Repeated three times.

PAT SPEARS: Three times.

MICHAEL RADECKI: 30 years, 30 years, 30 years. So it's a good point, Pat. So each of these case scenarios is 30 years. This was one particular 10-year period repeated three times, so it assumes 30 years of low hydro conditions. This is 30 years of actual conditions. This is one 10-year period repeated three times, 30 years of high hydro conditions. So if you wanted -- the low hydro and the high hydro are extreme cases. Base hydro represents actual flows, actual generation for 30 years. So if 30 years were to repeat itself in some similar format, that's what we'd see.

PAT SPEARS: Is this only purchase of wind power or does it assume that there's a base load of coal-fired power over this period also? Is that underneath based on your base data, the history?

MICHAEL RADECKI: I don't -- I'm not getting the point of your question, Pat.

PAT SPEARS: Is the base load of coal-fired power figured into this equation and this formula? Is it assuming that or is this completely wind power as supplemental hydropower, no other power at all?

MICHAEL RADECKI: The model PROMOD, the software used the hydro generation patterns and load patterns and wind energy production patterns all matched for the year 2000, so if for some reason -- and, Rick, please correct me if I'm wrong -- that hydro generation and the wind serving Western load did not meet the load for a given point in time, the software purchased energy off the market to meet our load. Is that correct?

RICK HUNT: That's right. I think to supplement Mike's answer, this is a simulation of the full region, so I think, Pat, the answer to your question is energy -- coal energy was available for purchase to meet Western's firming needs because it's a full regional simulation, not just Western's resources.

PAT SPEARS: Then that's also assuming current market prices, today's prices for the coal power, but using 5 cents for wind power as the price throughout the purchase period?

MICHAEL RADECKI: No, the study year was 2011, so it's in 2011 -- no? Well, I'm sorry.

RICK HUNT: For these values this is a 30-year simulation, so it's 2011 through 2040 and the prices escalate through time at various rates depending on the commodity and then these values you see here are that present value back to whatever dollars those are in.

MICHAEL RADECKI: 2011.

PAT SPEARS: So what's the base price of coal-fired power during this period? If wind is 5 cents, what is coal?

RICK HUNT: It's not a specific number, it's based on the price of coal at each plant and there's a forecast associated with each of those values, so it's -- there's a lot of detail into that answer. It's kind of hard to say, you know, it's based on the price of coal forecasted out 30 years.

PAT SPEARS: Well, that's my point. Can you give us an average of what that is? And then there was this figure with no carbon tax and then there was a carbon tax assumed in there and the rate that we use was what, 30? Was it 30 bucks?

MICHAEL RADECKI: Oh, the carbon the penalty?

PAT SPEARS: The penalty, what was it?

RICK HUNT: That's actually -- that value changes through time. It's documented on the website. I don't know the value off the top of my head, but we can get you both of those, actually.

MICHAEL RADECKI: I think 20 or 25.

RICK HUNT: It actually starts out relatively low and escalates up.

PAT SPEARS: We would appreciate some more information --

RICK HUNT: Yeah, we can definitely document all that.

PAT SPEARS: -- so we can understand that. Thank you.

JOHN STONE: John Stone, Yankton Sioux Tribe. Just to better understand how you arrived at a base hydro flow you said off of historic data. You know, just for my own sake, last year I think WAPA or the flow of the river was at 38 percent of normal last year and this year the Corps is projecting a 50 percent annual runoff or annual -- the guy's shaking his head here.

MICHAEL RADECKI: Annual runoff?

JOHN STONE: Okay. Do you have any answer for me? No? You were shaking your head, so I was just wondering what that was about.

But is that comparative to -- the base rate would be comparable to the Corps' projection of a 50 percent annual flow this year?

MICHAEL RADECKI: The base hydro condition or the base case that we used, I'll take you back to -- back to this slide.

JOHN STONE: That's an average, then, of all of those flows?

MICHAEL RADECKI: Those are the yearly flows for

1968 to 2007. The base case is 30 years of actual flows.

JOHN STONE: Okay. So your low, your high, and you're middle came out of that data set?

MICHAEL RADECKI: Yes.

JOHN STONE: Okay. Thank you.

MICHAEL RADECKI: Yes?

BOB GOUGH: Bob Gough, Intertribal Council on Utility Policy. There was no attempt at putting probabilities on those extreme cases, was there?

MICHAEL RADECKI: No, we did no probability analysis, Bob, it was to show the extreme.

BOB GOUGH: I mean, the opportunity of receiving 30 years of wet, high, full dams versus 30 years of drought, we haven't contemplated that discussion in this analysis?

MICHAEL RADECKI: We have not.

QUSI AL-HAJ: Qusi Al-Haj. So your recommendations were not based on a set of assumptions? I mean, the fact that you're in support of a demonstration project being constructed, was there some underlying assumptions made as far as predicting what the flow will be or what the carbon legislation would look like?

MICHAEL RADECKI: No. The recommendation for a demonstration project, it was based on essentially the historical analysis. The fact is that Western is always on the market -- almost always on the market purchasing energy to meet our firm power obligations. We recognize that our historical analysis conclusions, that 0 to 330 megawatts, didn't exactly hit the right mark, but we also know that we are on the market purchasing energy, so we do need some energy, we just don't know what the maximum amount that we can integrate for our, Western's use to meet its firm power obligations, we don't know what that maximum amount is.

QUSI AL-HAJ: But as far as whether carbon legislation would be tightened or loosened, I mean, that's -- because that is counterintuitive, your findings or the study's finding with the carbon legislation.

MICHAEL RADECKI: And that's one of the reasons in the recommendation that we do some additional analysis. One, to further refine what the optimal amount of wind to integrate into the system is, but also to look at -- do further study into the impacts of carbon legislation.

QUSI AL-HAJ: Thank you.

MICHAEL RADECKI: Yes?

DELL PETERSEN: My name is Dell Petersen from Ellsworth Air Force Base. My question is that many of the -- many of your customers have federal mandates for the purchase of renewable power. Do you have a feel for the total market, market potential of that mandate to your system? In other words, by 2025, for example, the Air Force is supposed to have a renewable power target of 25 percent, so that represents a potential purchase by the Air Force of power that is distributed through the WAPA system. What is that in total for your distribution network? Have you arrived at anything that projects that?

MICHAEL RADECKI: Yeah, I don't -- Dell, I don't know if I can directly answer that question. You know, I made a comment earlier in the presentation that the two levels that we looked at, the two penetration levels we looked at represented 23 and 25 percent wind penetration in the Western system based on a maximum annual load, but only a portion of that energy would actually be serving Western's load.

As of today I don't believe Western has established a policy or procedure as to how renewables that are integrated into the system will be applied to our customers. Several customers in different states, Minnesota, Iowa, they have renewable mandates. Our federal customers have renewable mandates. There has been no decision as to how the renewables in the system will be accounted for.

JOHN STONE: Would that be similar to the Native American WAPA allocation that he's talking about, to be able to study that federal purchasing ability? So does WAPA -- they do it on that level. Is that comparable to what the gentleman is speaking about? Because we're mandated that we only purchase power that's generated from the hydropower and then we get a discount for use of that sole source of renewable power.

MICHAEL RADECKI: I apologize, I'm not following the root of your question. I believe the Native American power allocation is different than what Dell was referring to.

JOHN STONE: Okay.

MICHAEL RADECKI: Bob?

BOB GOUGH: Bob Gough, Intertribal COUP. The outcome of this, the recommendations, that also hasn't contemplated the benefits of multiple projects going on the grid at the same time and what the benefits, the increased capacity value of wind and the number of larger distributed areas hasn't been accounted for in this study?

MICHAEL RADECKI: I would -- Bob, I'd respond that it has been included in the study, although not specifically addressed in text, remembering the

300 megawatts of non-Tribal wind that is distributed within the region and the Tribal wind project. So the results of this study reflect distributed wind generation in the system serving Western load, but we specifically did not discuss in text benefits of distributed generation.

BOB GOUGH: But it doesn't treat bought distributed Tribal wind.

MICHAEL RADECKI: No, it does not.

Any other questions, comments? Yes, Sir.

LOUIS JANIS: After the demonstration project --

MICHAEL RADECKI: Sir, could you --

LOUIS JANIS: Oh, Louis Janis with Oglala Sioux Tribe. After the demonstration project is WAPA willing to allocate more purchasing power of wind or are they going to determine that from this?

MICHAEL RADECKI: I think that's a question I can't answer. We don't know what the future's going to bring once this report is sent to Congress.

LOUIS JANIS: And who sets that standard with the amount of coal that you use versus the amount of your water or your hydro, is that Congress or is that WAPA?

MICHAEL RADECKI: Your question is who sets the amount of coal as opposed to the amount of hydro use?

LOUIS JANIS: As far as allocating the amounts and how renewable energy is to fit into that diagram of energy, of the developing energy of renewables.

MICHAEL RADECKI: I don't believe I can give you an answer to that today. It's something I'm going to have to look into. I don't believe anybody sets a standard between or a reference between coal and hydro.

LOUIS JANIS: Because you are using 85 percent, aren't you, of coal?

MICHAEL RADECKI: The amount of the energy Western purchases in any given year, which could be from coal, could be from natural gas, it depends on what's available or what contract arrangements we make.

LOUIS JANIS: So who sets that value?

DOUG HELLEKSON: Mike, maybe I can help in the answer. All of Western's contracts with our customers are a set amount of power, correct, up to the limit of what we have to market, so 2,000 megawatts. So we're committed to make sure we provide 2,000 megawatts to our customers every year, so that is really the benchmark that we have to shoot for. If the hydro generation can supply all 2,000, we buy zero coal. If it can't supply it, we buy whatever the market provides. The market may be coal, it could be an integration of wind and coal. We don't know what the source is. In this area, generally coal is a predominant supplier so we can make that assumption, but the 2,000 megawatts is what we have to meet every year.

LOUIS JANIS: Okay. So if that 2,000 was to go up --

DOUG HELLEKSON: It won't.

LOUIS JANIS: It won't? Why is that?

DOUG HELLEKSON: Because we're mandated to only market the hydro generation resources --

LOUIS JANIS: And who mandates that?

DOUG HELLEKSON: That's Congress and the mission of our board.

LOUIS JANIS: That's the question I had, you know, what type of mandate power does WAPA have versus Congress and what are the key roles of Tribes involved in this process. That's just a question.

DOUG HELLEKSON: Does that help, what I provided you?

LOUIS JANIS: Yeah, because I know that came up too is if WAPA would be willing to purchase more, you know. Like you said, you only mandate to that 2,000. That answered my question. So it's not your decision if you are going to purchase more, it's just that mandate, setting that mandate higher or -- yeah.

MICHAEL RADECKI: Thanks, Doug.

Any other questions or comments?

(No response.)

MICHAEL RADECKI: Reminder, February 13th submission of written comments on the work plan E-mailed or written. You have the information in your handouts today.

I would just like to, once again, thank everyone for braving the weather and coming out here. I know some of you came from the eastern side of the state and I know you had some weather to drive through and I appreciate your presence. Look forward to seeing your written comments and just thanks for being here this afternoon.

(Public Meeting concluded at 2:53 p.m.)

STATE OF SOUTH DAKOTA)
) SS. CERTIFICATE
COUNTY OF PENNINGTON)

I, SANDRA C. SEMERAD, RMR, Court Reporter, hereby certify that the foregoing pages 1 through 57, inclusive, are a true and correct transcript of my stenotype notes.

Dated at Rapid City, South Dakota, this 21st day of January, 2009.

____

SANDRA C. SEMERAD, RMR
Registered Merit Reporter
My Commission Expires: 3/7/12

Stanley Consultants INC.

Project No. Western Area Power Admin Page No.

Subject Wind-Hydro Feasibility Study

Computed by Date

Checked by Date

Approved by Date Sheet No. of

Public Comment Meeting 1/13/09 1-4pm

	Name	Affiliation	email/contact
1	Jim Bach	WAPA	jbach@wapa.gov
2	Don Metzger	Just Wind	Dmetzger@justwind
3	Jeff Metzger	Just Wind	JMetzger@Justwind.com
4	Doug Hellekson	Western	
5	Jody Sundstrom	" "	Sundstrom@wapa.gov
6	Jay Miller	"	jay.miller@wapa.gov
7	FAITH SPOTTED Eagle	Yankton Sioux Tribe	eagletrax@hotmail
8	Sharon Drapeau	" " "	sharon_d99@yahoo.com
9	Rick Hunt	Ventyx	richard.hunt@ventyx.com
10	Mike Radecki	WAPA	Radecki@wapa.gov
11	Kim Massey	Stanley Consultants	masseykim@stanleygroup.com
12	Mike Swenson	US Army Corps of Engineers	michael.a.swenson@usace.army.mil
13	Mike Haines	Fox Ridge Energy Education Institute	mhaines@gwtc.net
14	MIKE TRYKOSKI	SDEIA	MIKETFR@RAPIDNET.com
15	Vic Simmons	Rushmore Electric	vsimmons@rushelec.com
16	John Stone	Yankton Sioux Tribe	ystew@yahoo.com
17	Jody Zephier	Yankton Sioux Tribe	zephierj@yahoo.com
18	Louis R. Janis	Oglala - Utilities OFC	loujan-55@yahoo.c
19	Vicky Wicks	freelance journalist	wicksvicky@hotmail.com
20	John B. LeVoe	Self. SDPB	jbdeyoe@yahoo.com
21	Andrea J Cook	Rapid City Journal	andrea.cook@lee.net
22	TRACY THORNE	WAPA	
23	Qusi Alkhaj	Senator Thune	qusi_alkhaj@thune.senate.gov
24	Dwayne Coleman	WHV	dm.coleman@rushmore.com
25	Greg Vaselaar	Western	
26	FRED MOUSSEAUX	OST UTILITIES	ostutilities@hotmail.com
27	Eric Scherr	Black Hills Corp	eric.scherr@blackhillscorp.com
28	CHET MILLS	NARP LLC	mills@NARPLLC.com
29	Pat Spears	Intertribal COUP	patspears25@gmail.com
30	Joe RedCloud	OST Econ. Dev. Office	joeredcloud@hotmail.com
31	Lisa Teeslink	Tetra Tech - 28CES/CEA	Lisa.Teeslink@[illegible].com

SC 3004 R4 898

Stanley Consultants INC.

Project No. ______ Page No. ______

Subject ______

Computed by ______ Date ______

Checked by ______ Date ______

Approved by ______ Date ______ Sheet No. ______ of ______

	NAME	Affiliation	email contact
32	DELL PETERSEN	ELLSWORTH	dell.petersen@ellsworthaf
33	Bob Gough	Intertribal COUP / WPA	gough.bob@gmail.com
34	WARREN KARLEN	Citizens Wind Energy	karlenranch@yahoo.com
35	Braden Houston		bhouston@CitizensEnergy.com
36			