DRAFT

December 12, 2008

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

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

Preface

The purpose of this report is to address the mandates outlined by Section 2606 of EPAct 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 the Energy Policy Act of 2005, Section 2606. 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.

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.

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 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. Western is negotiating wind resources from 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. Although 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), the 2606 legislation is looking to test the feasibility of a Tribal Wind Demonstration Project in the near term. (All wind project sizes are provided as nameplate values unless specifically indicated otherwise.)

To conduct the feasibility assessment for this study, a 50 MW Tribal Wind Demonstration Project was used. 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.

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.

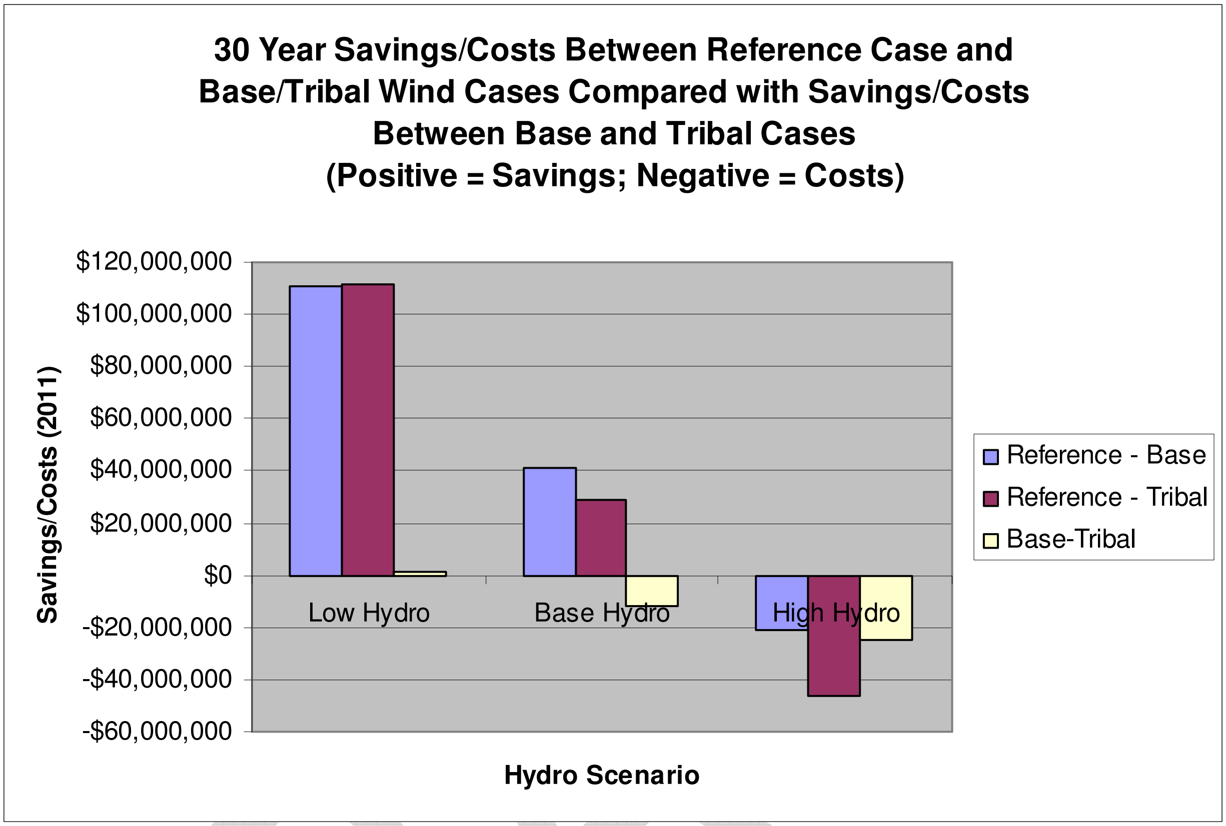
The economic impact of additional tribal wind in the Balancing Area was also analyzed. Zonal market simulations (using PROMOD IV) generated costs to Western's customers of the wind used to meet Western's load over 30 years for the six scenarios (two wind scenarios for each of the three hydro scenarios). These 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 wind generation to Western's generation portfolio during a high hydro generation year, costs Western's customers money.

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 used 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. 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.

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.

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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 according to the outline of the legislation:

- 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, 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 Upper Great Plains Region (UGPR) with a regional office in Billings, Montana, markets the Eastern Division of P-SMBP-ED. The Rocky Mountain Region, with a regional office in Loveland, Colorado, markets the Western Division of P-SMBP-WD. The 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. 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. 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 more than 12 billion kilowatt-hours of firm energy 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 will be presented at a Public Comment meeting in Rapid City, South Dakota, on January 13, 2009. The WHFS report will be 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--*	
A) *the economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership*	**4**
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) 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

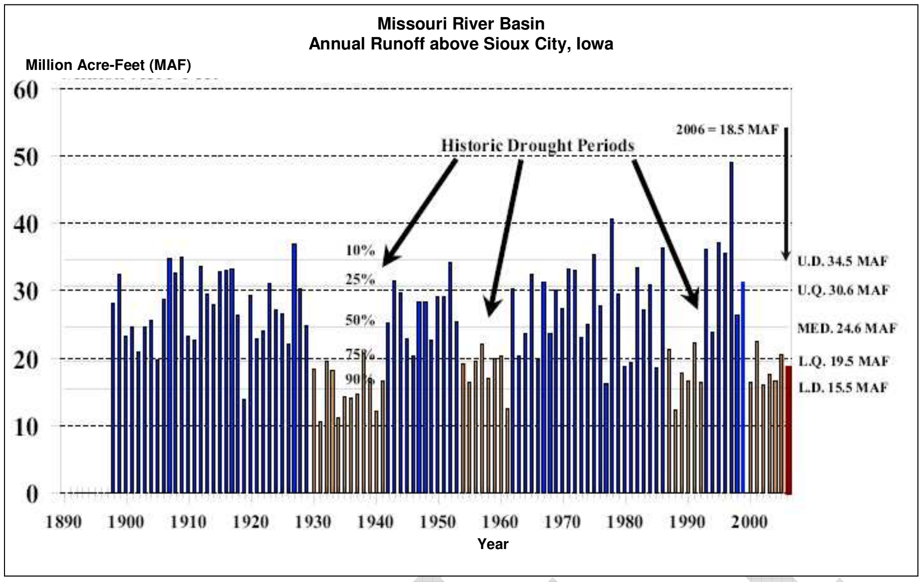
A minimum and maximum potential for energy that could be used to replace existing purchases was developed from Western's historical generation and load data. Minimum potential should be characterized in a high generation year when very few purchases are required; maximum purchase potential occurs in 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.

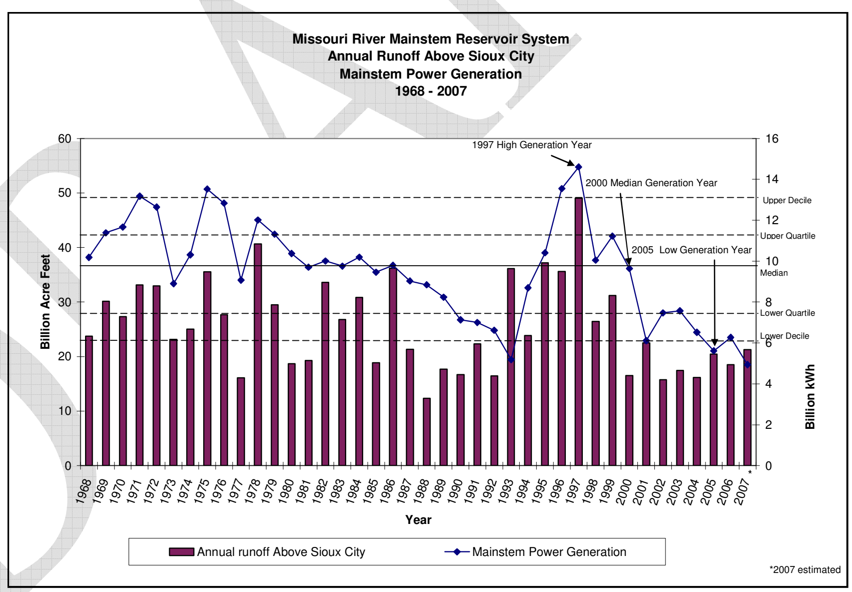
Western Historical Data

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

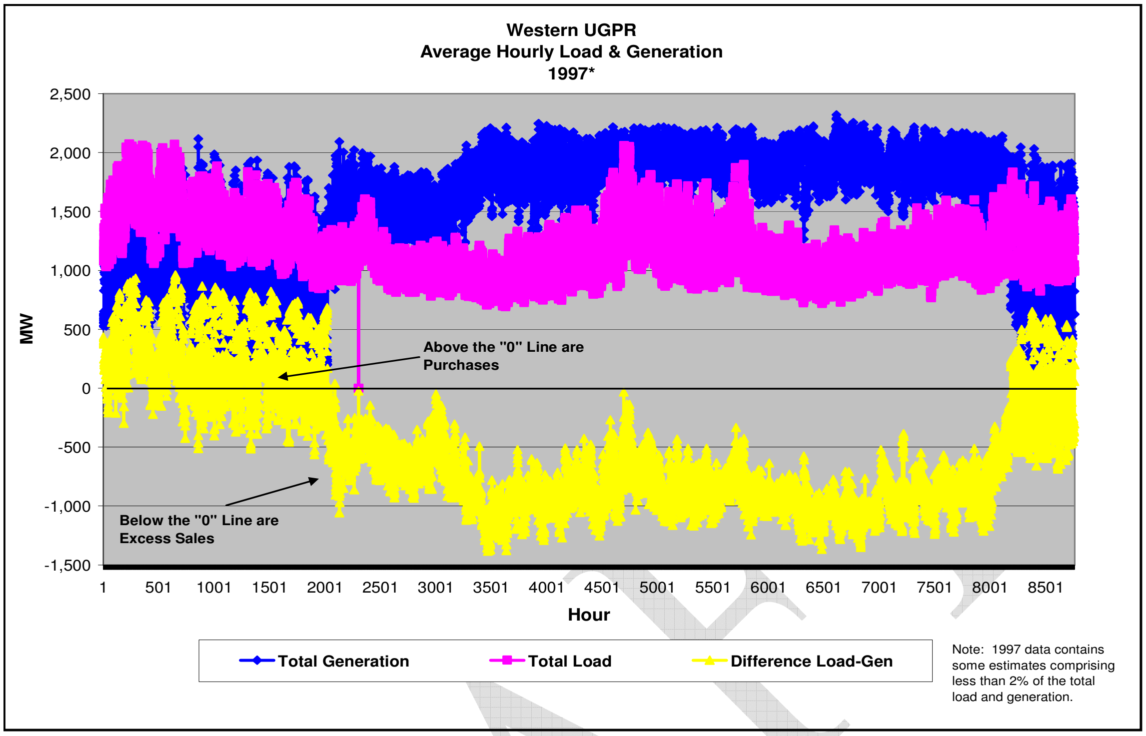
As documented in Figure 2-2, although the annual runoff and power generation do not always align, system storage and refilling requirements can create either a high water runoff year that is also a low generation year (i.e., 1993) or a low water runoff year that is a high generation year (i.e., 1998). 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 within the range of 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.]

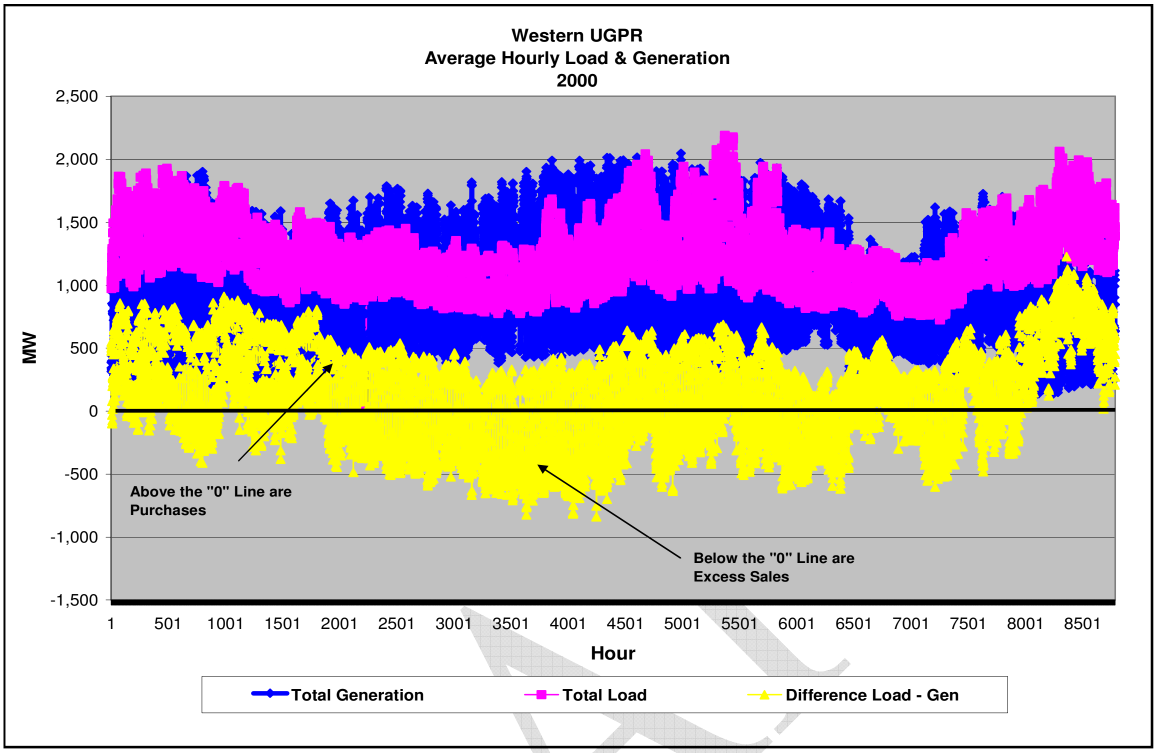
Western Purchases

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).

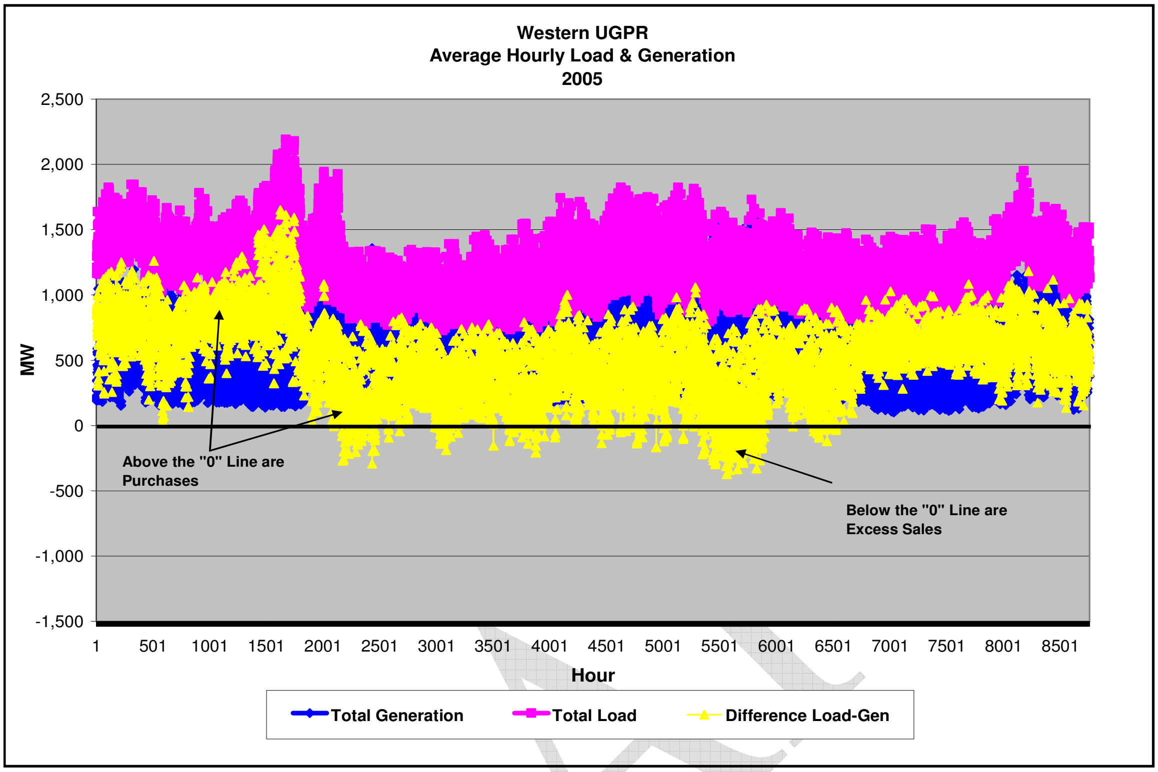
HIGH HYDRO Hourly Load, Generation, & Purchases, 1997
Figure 2-3



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



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

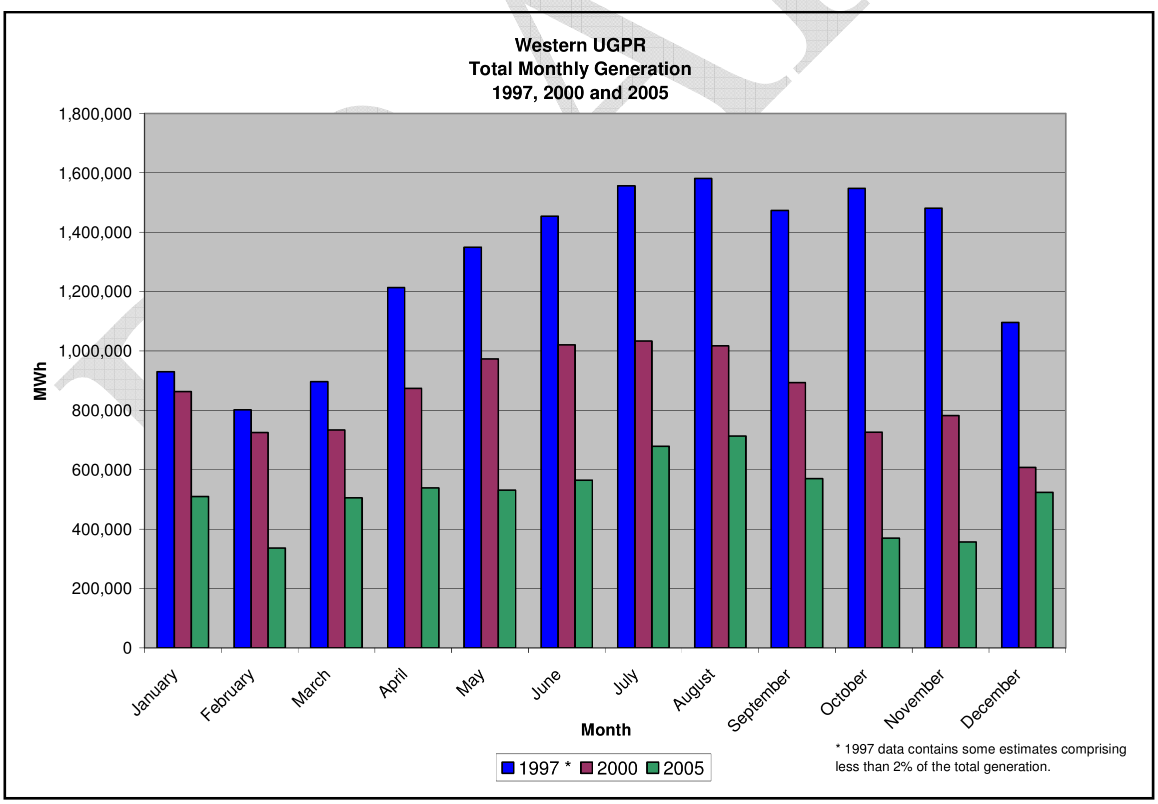


Seasonal/On and Off Peak Variation

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.

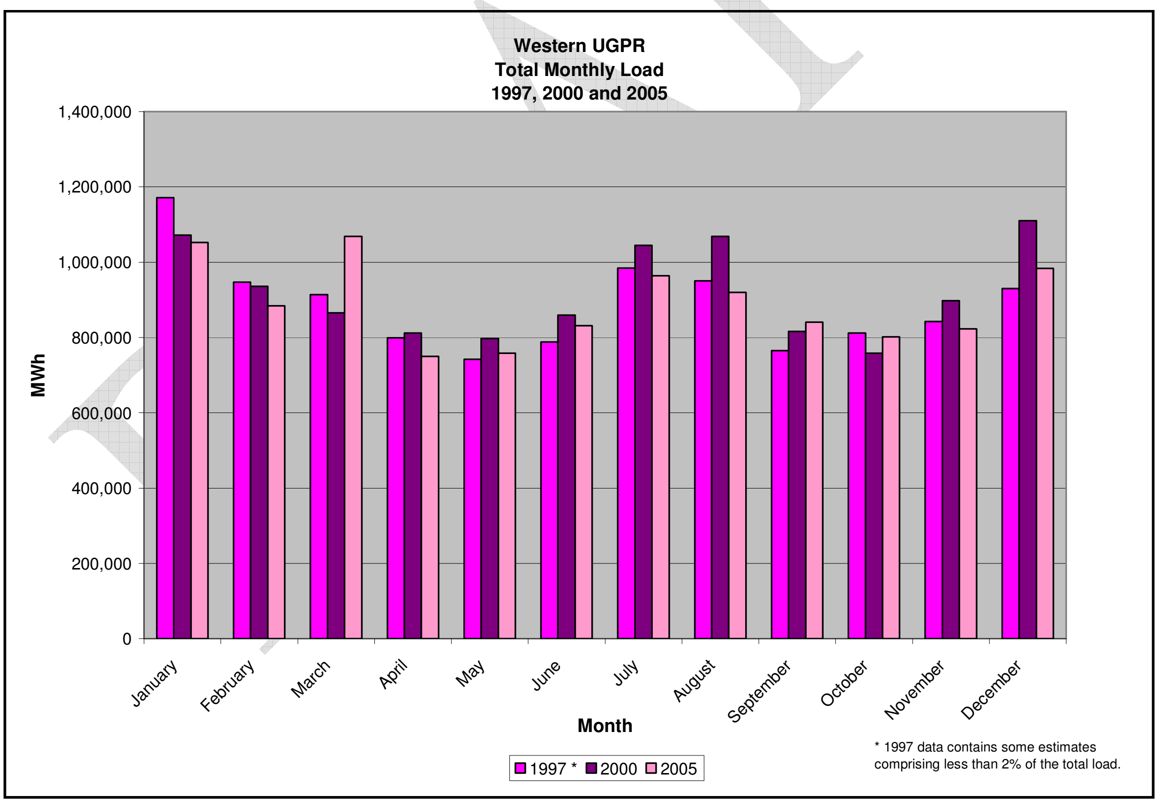


Total Monthly Generation: 1997, 2000, & 2005
Figure 2-6

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

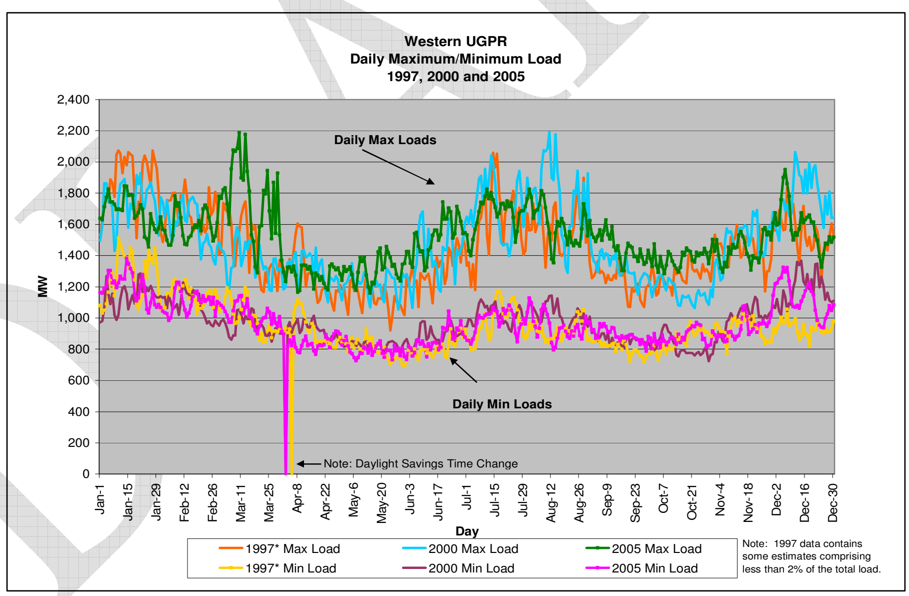
As seen in Table 2-3, total load energy requirements for each of the three years varies less than 4 percent, but does not track with water/generation level.

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—

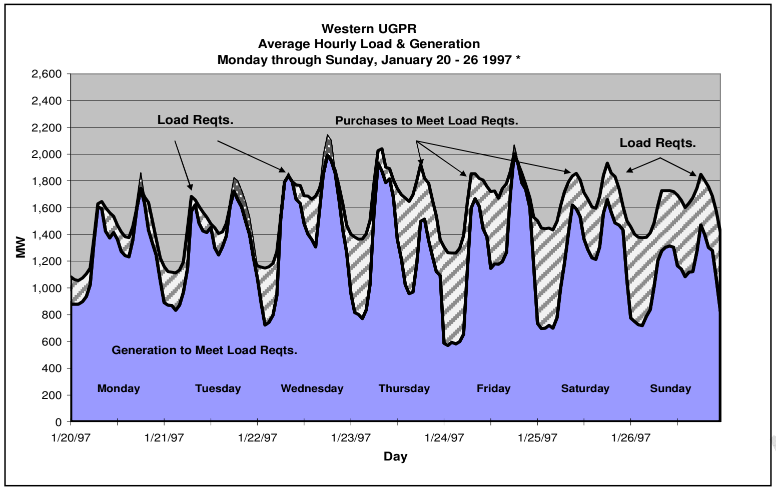
purchases occur during winter months even during a high generation year (1997), while a small amount of sales occur during on-peak summer hours even in a low generation year (2005).

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.

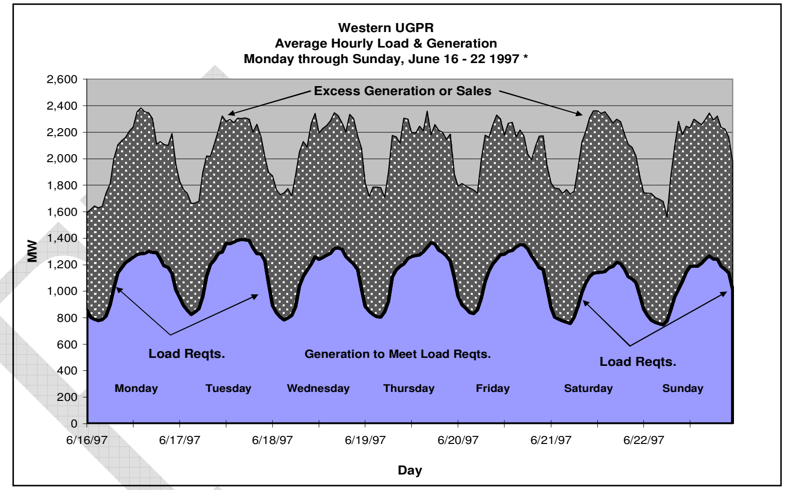
HIGH HYDRO SCENARIO

Winter

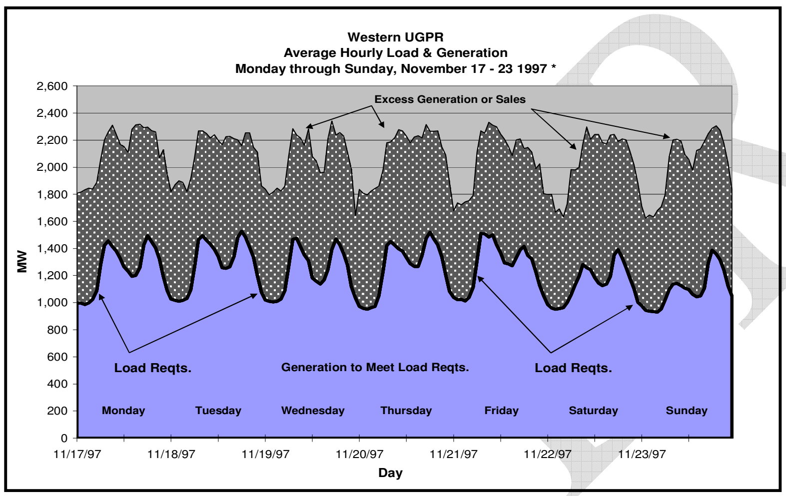


Hourly Load & Generation, January 20-26, 1997
Figure 2-9

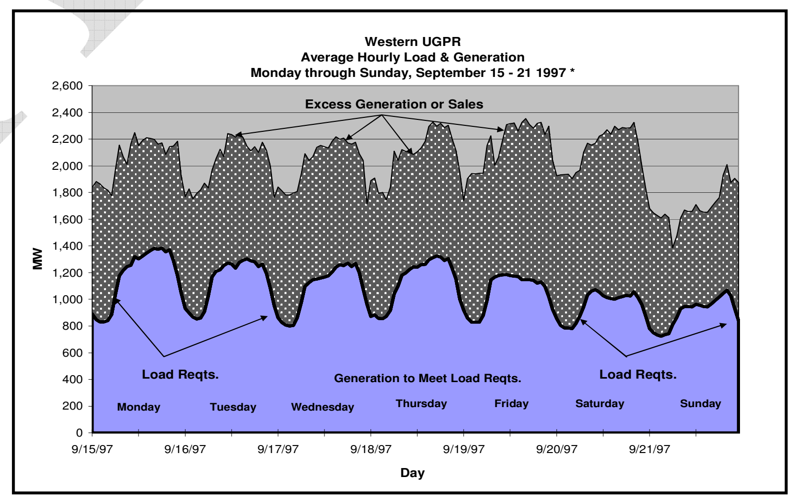
Summer



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



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



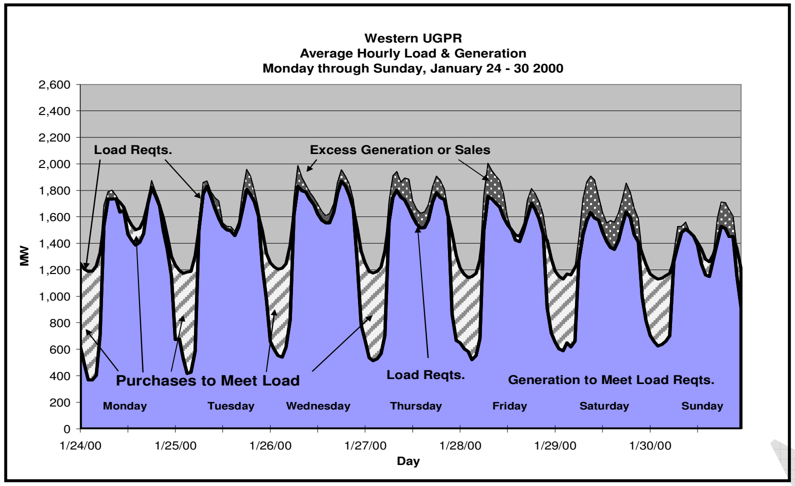
Hourly Load & Generation, September 15-21, 1997
Figure 2-12

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.

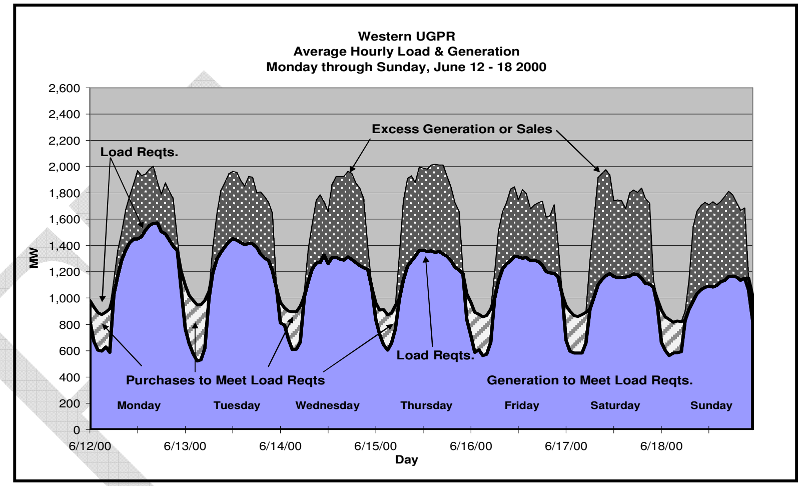
BASE HYDRO SCENARIO

Winter

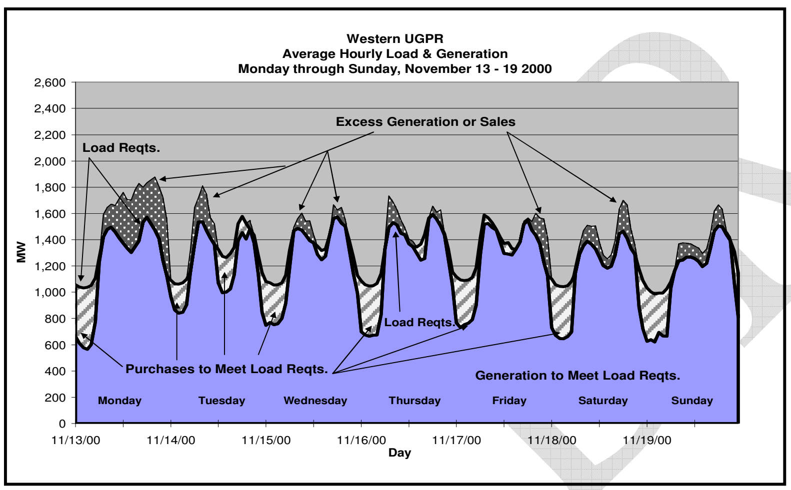


Hourly Load & Generation, January 24-30, 2000
Figure 2-13

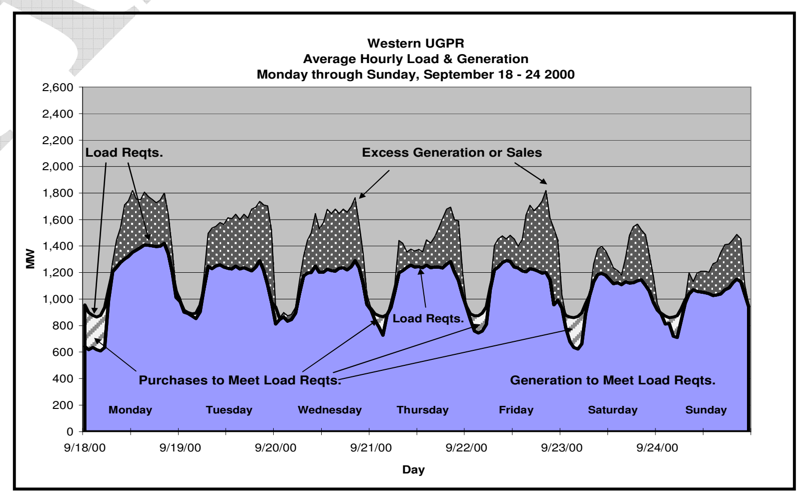
Summer



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



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

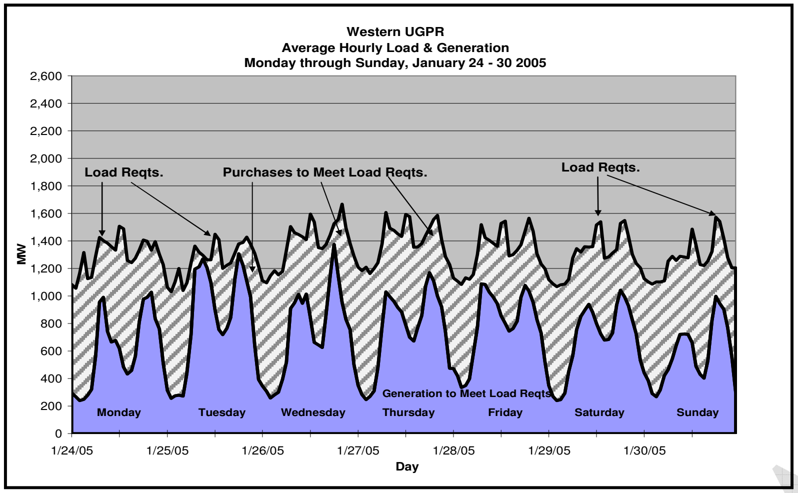


Hourly Load & Generation, September 18-24, 2000
Figure 2-16

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

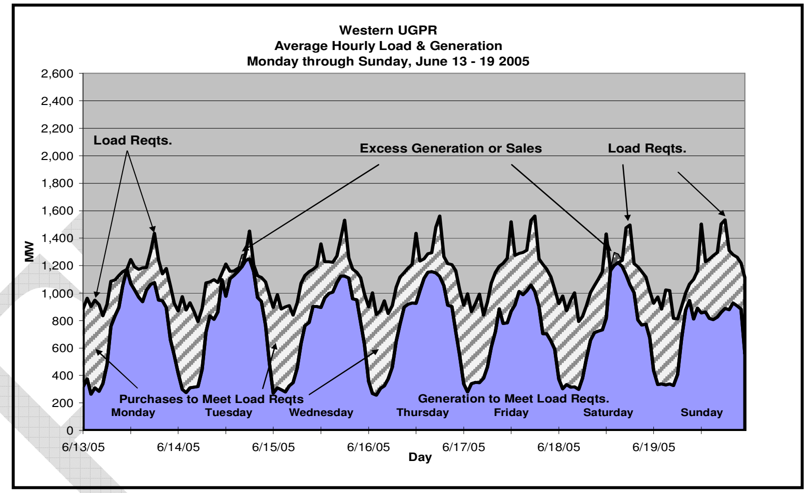
LOW HYDRO SCENARIO

Winter

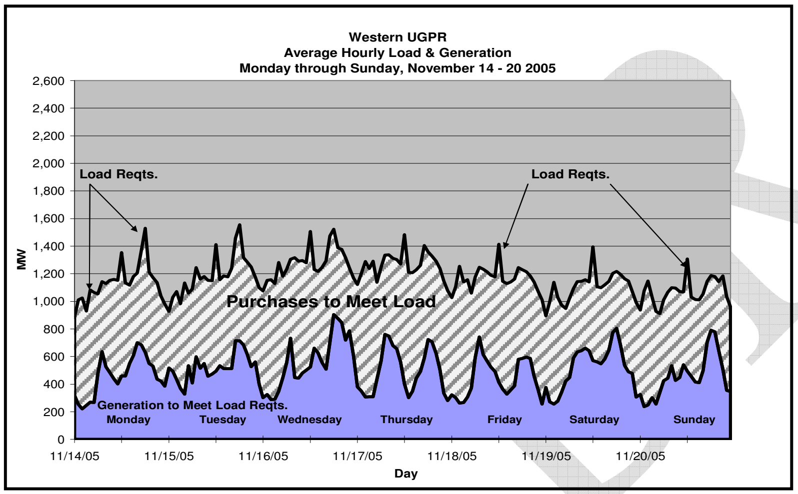


Hourly Load & Generation, January 24-30, 2005
Figure 2-17

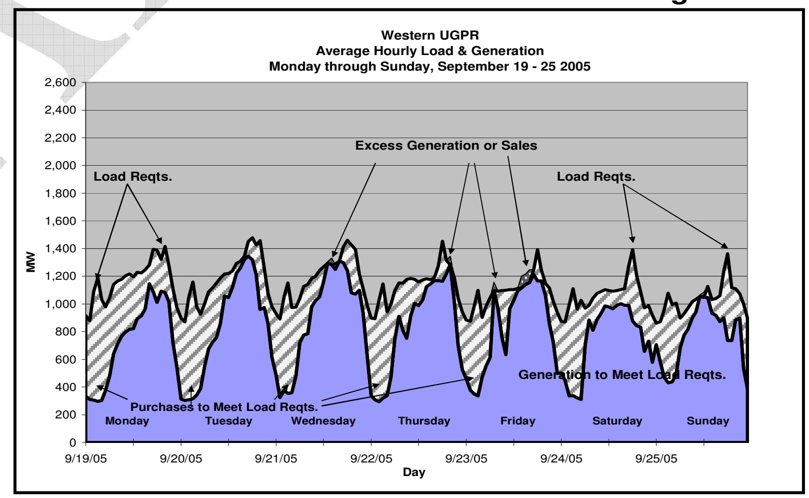
Summer



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 20MW 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 9 of the last 39 years (see Figure 2-2).

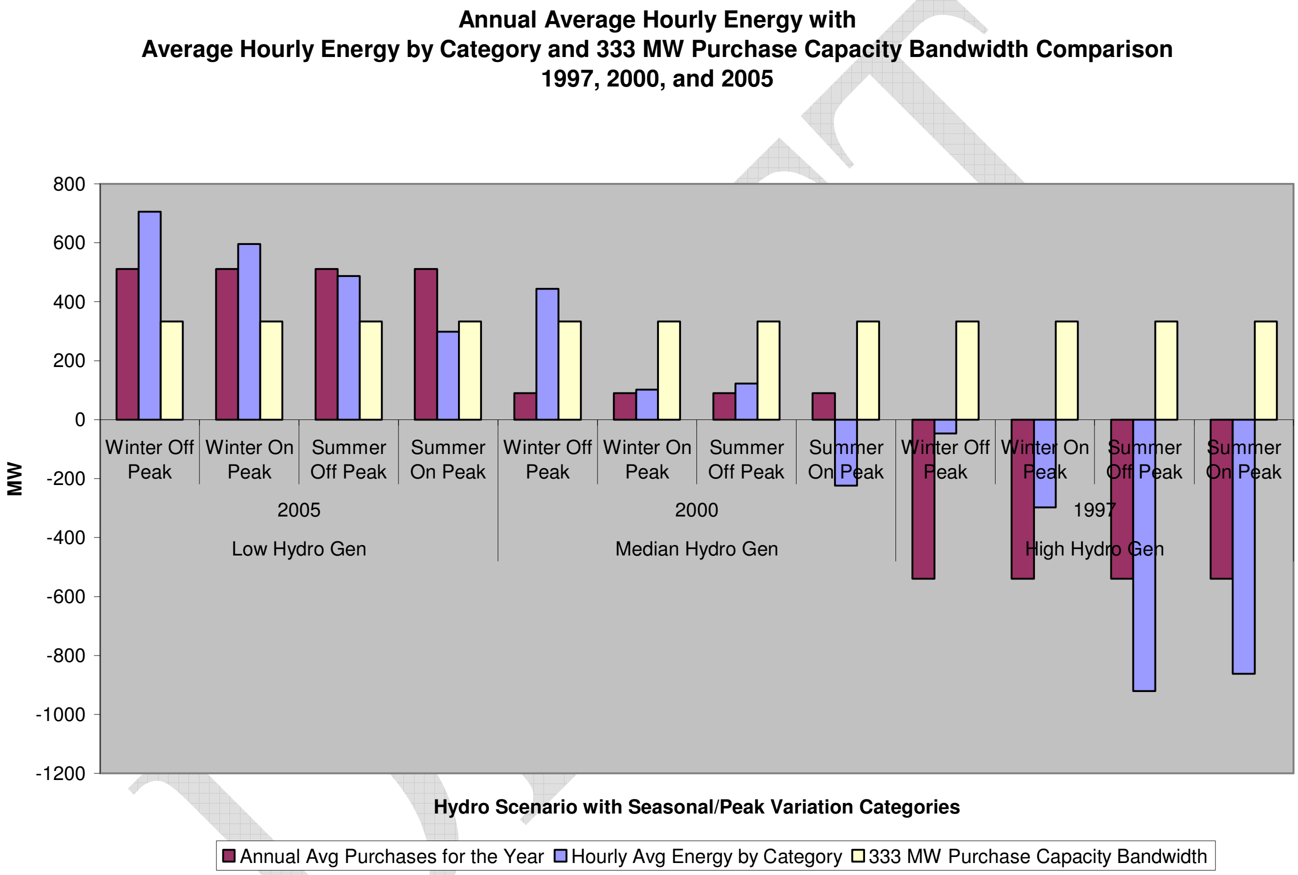
Table 2-4 Average Three Year Hourly MW Purchases/Sales
(Positive = Purchases; Negative = Sales)

	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.

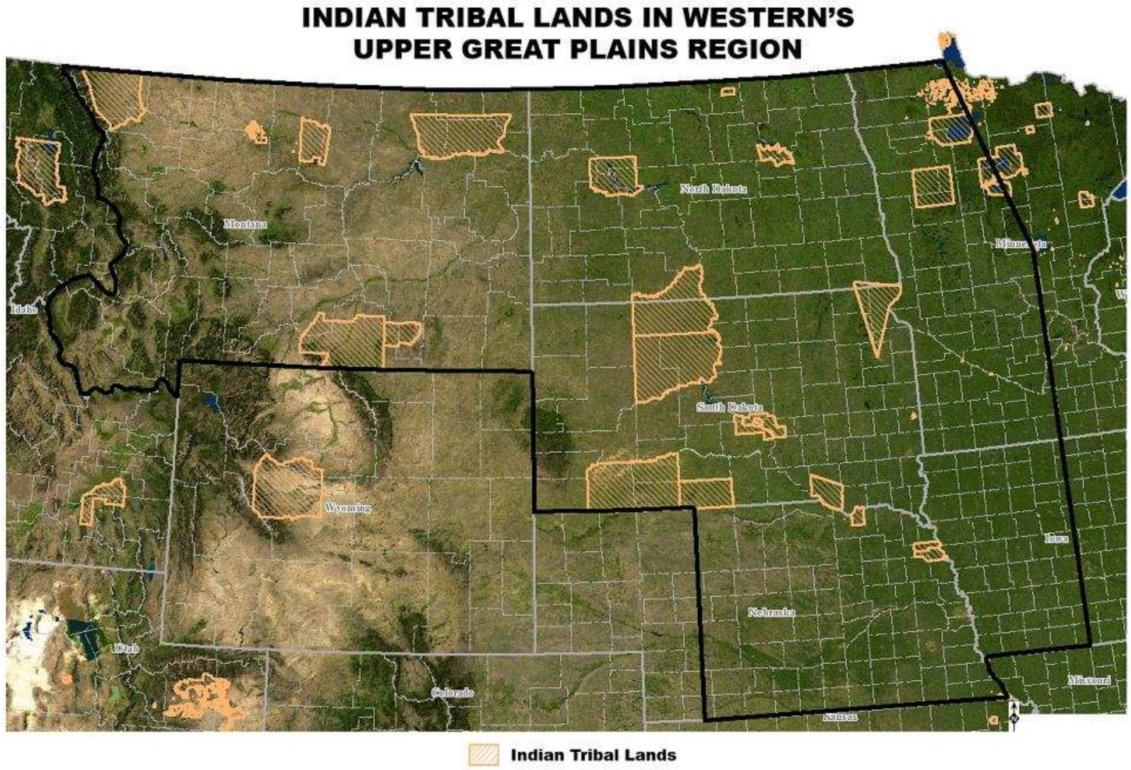
Work Element 3 – Wind Project Identification

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). The Native American Customers Post 2000 listed in the CROD follows:

- 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 WHFS 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. 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.

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.

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 following areas were monitored in this study: XEL, MP, SMMPA, GRE, OTP, MPW, MEC, NPPD, OPPD, LES, WAPA, MH, SPC, and DPC. 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

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

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

Low Hydro Generation-Years 1998-2007 repeated 3 times. Average annual generation = 7.838 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
Exiting 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 carry 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
Exiting 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 CO2 emissions allowances. A composite view on projected CO2 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). 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 the 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

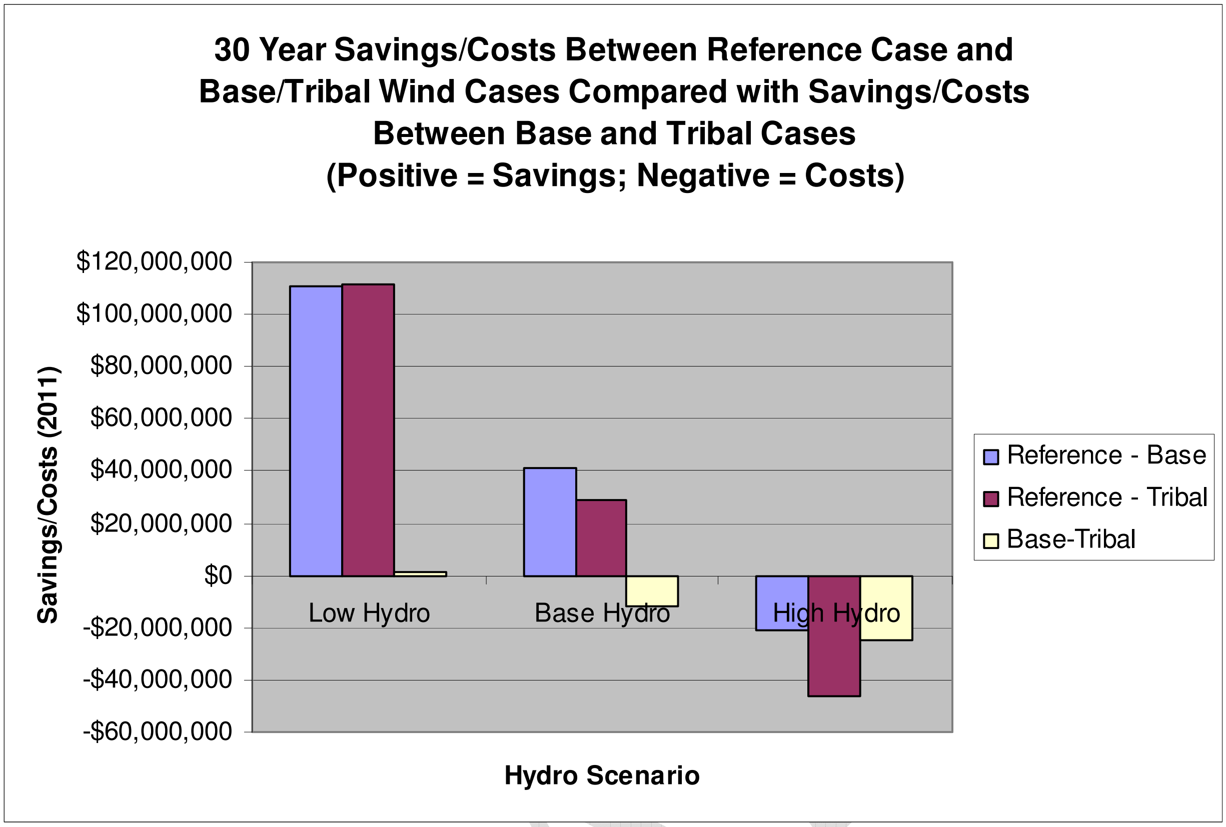
Finally, comparison between the BaseWind and TribalWind cases for the three hydro scenarios is displayed in Table 2-17 (as shown in Table 2-15 column B-C). Here, only the LowHydro case shows a savings to Western's customers for the additional 50 MW of tribal wind. Both the BaseHydro and HighHydro scenarios 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 the 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. 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

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 300MW to determine an ideal name plate capacity of wind to serve Western load obligations, no blanket economic assumptions can be made below the 300MW 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.

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 50MW 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 Section 2606 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).

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.

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 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.

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.

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.

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.

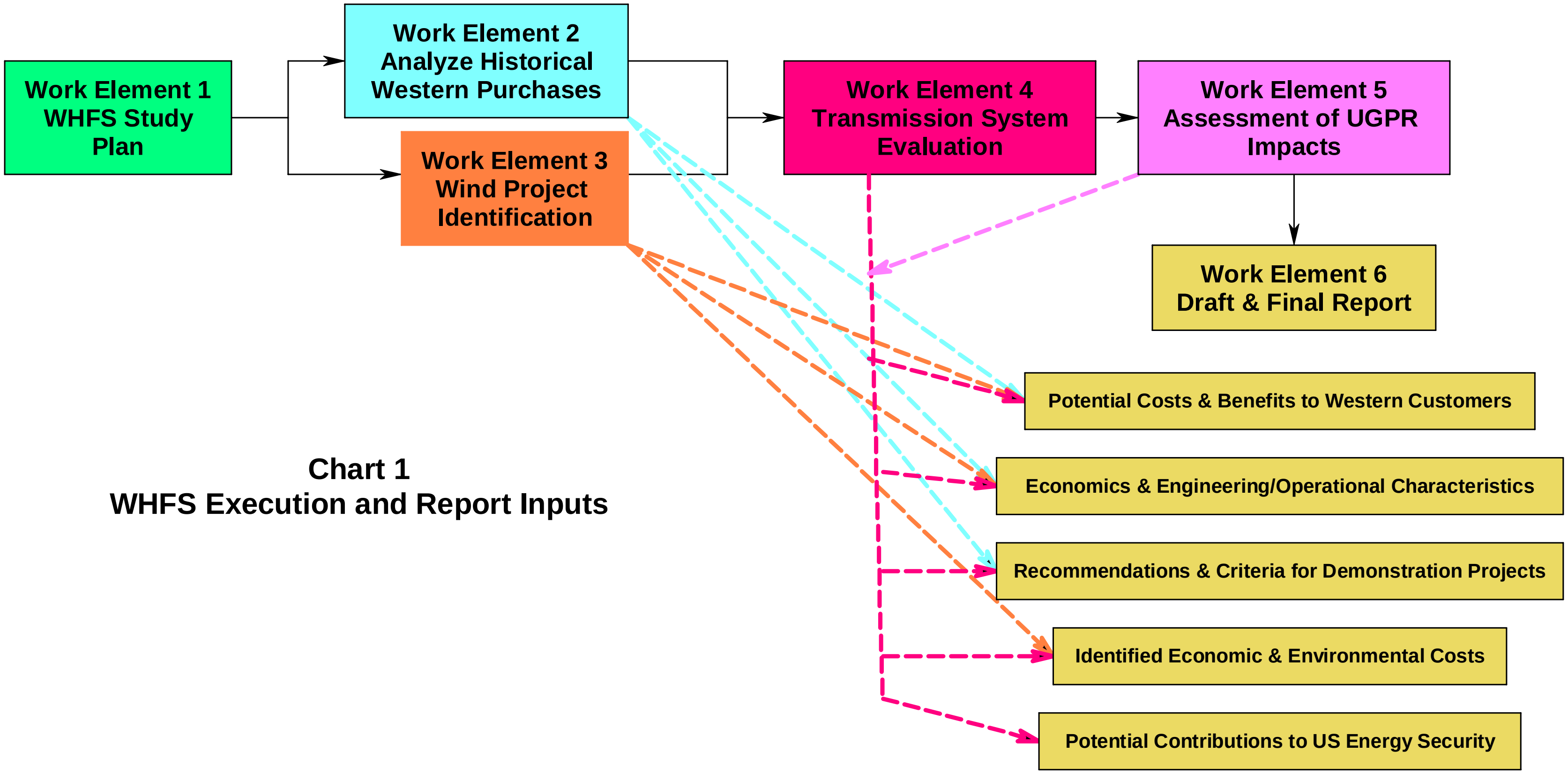


Chart 1
WHFS Execution and Report Inputs

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*

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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

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Tel: (303) 463-4979 Fax: (303) 463-8876

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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.

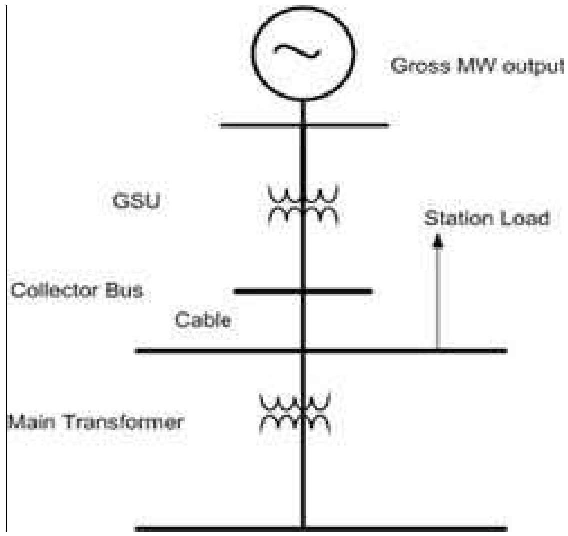
Please review EPAct 2005, Title XXVI, Section 2606 for details on the requirements of the Wind and Hydropower Feasibility Study. For more information on the WHFS Wind Demonstration Project, you may contact Michael Radecki, Energy Services Specialist, Western Area Power Administration, 406 247 7408 radecki@wapa.gov.

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.

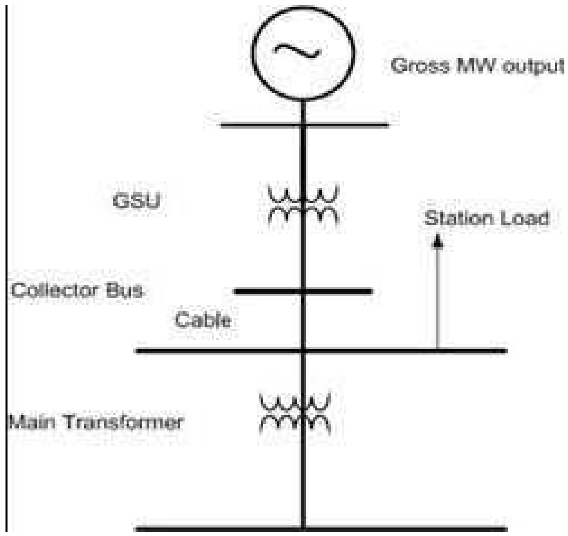
Please review EPAct 2005, Title XXVI, Section 2606 for details on the requirements of the Wind and Hydropower Feasibility Study. For more information on the WHFS Wind Demonstration Project, you may contact Michael Radecki, Energy Services Specialist, Western Area Power Administration, 406 247 7408 radecki@wapa.gov.

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	

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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

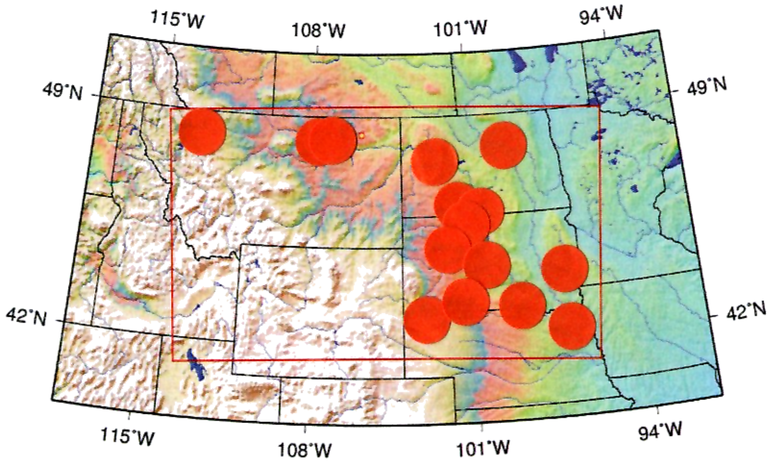

Figure 1. Domain utilized for Phase 1 with wind plant locations identified.

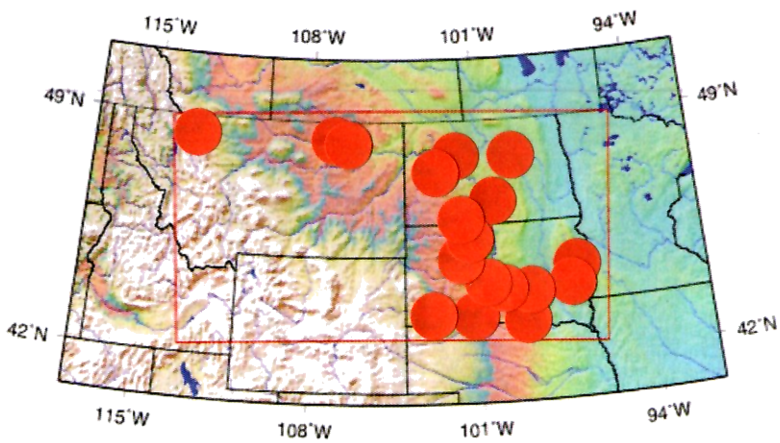

Figure 2. Domain utilized for Phase 2 with wind plant locations identified.

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

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

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www.enernex.com

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.

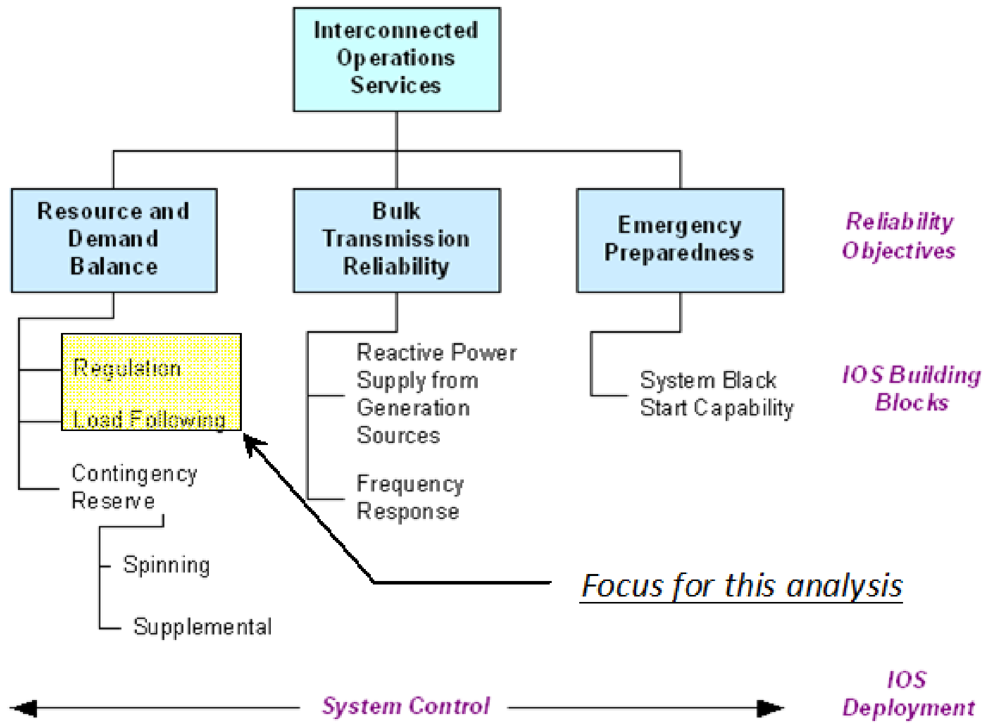


Figure 1: NERC Interconnection Operations Services (IOS) building blocks.

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.

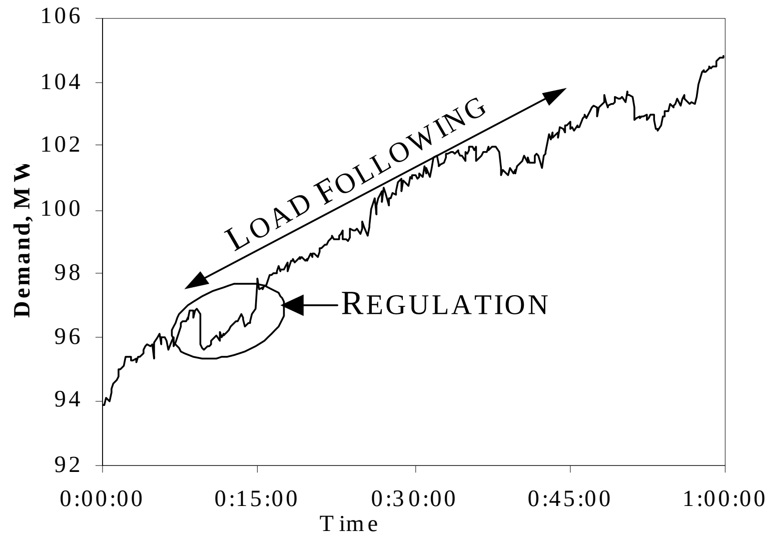


Figure 2: Illustration of regulation and load following from NREC IOS Reference Document

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.

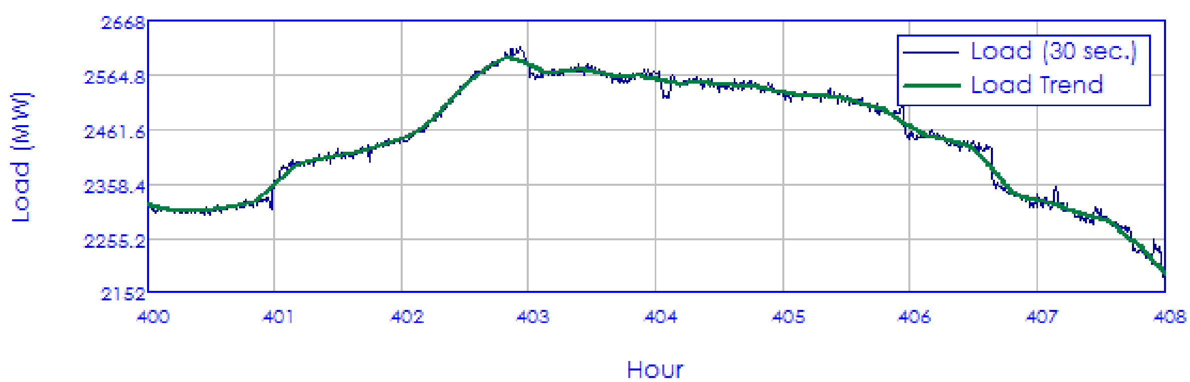


Figure 3: Extracting the regulation characteristic

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.

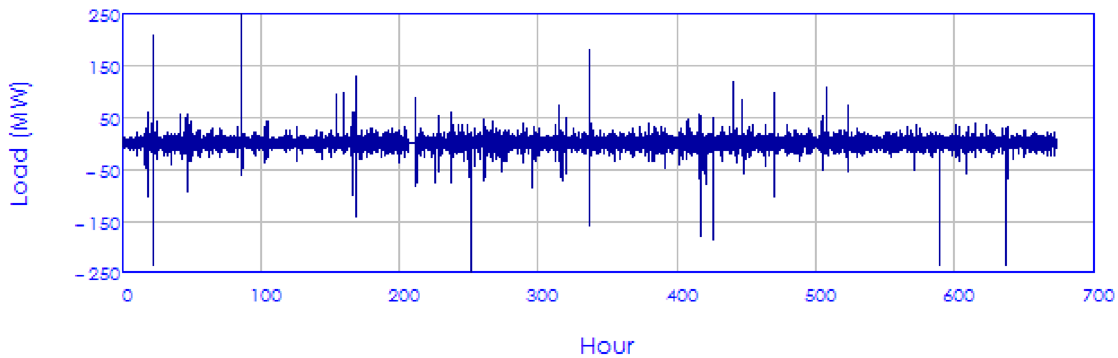


Figure 4: "Regulation characteristic" of WAPA load

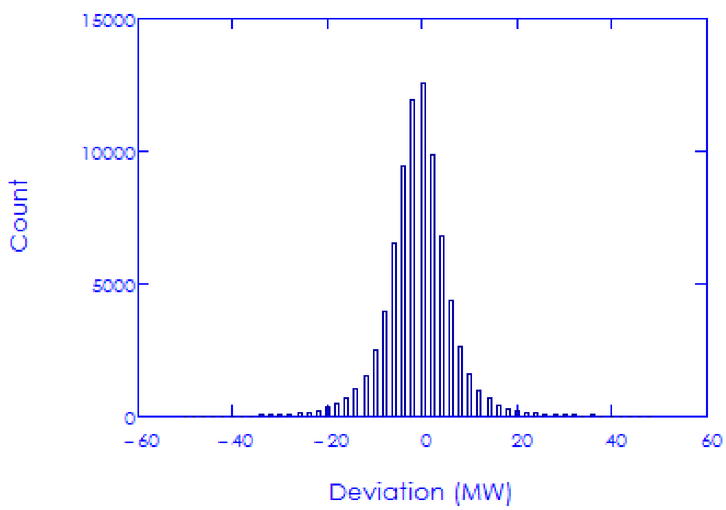


Figure 5: Distribution of WAPA load variations from 20-minute rolling average

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.

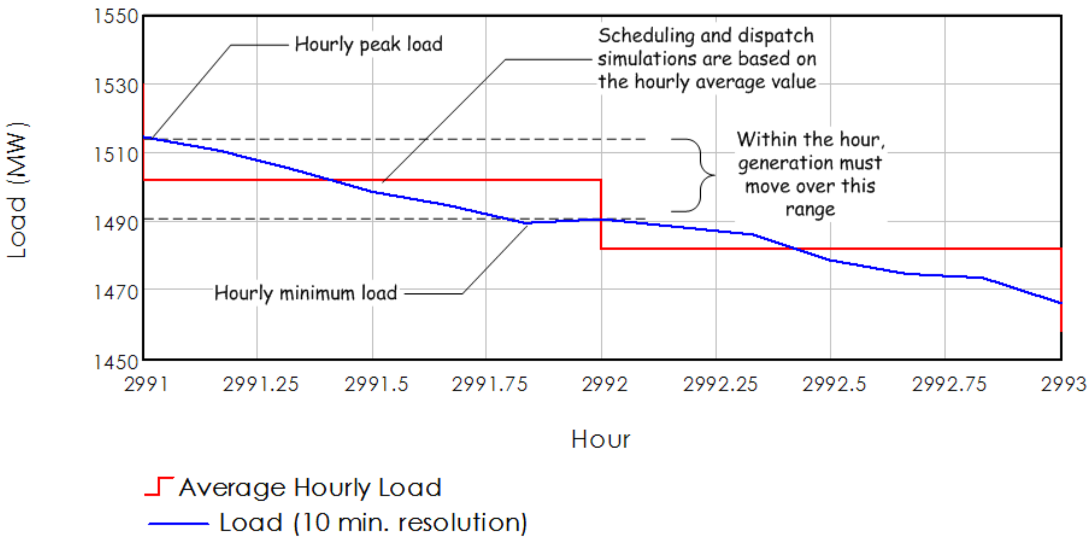


Figure 6: Hourly average and ten-minute load – WAPA load data

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.

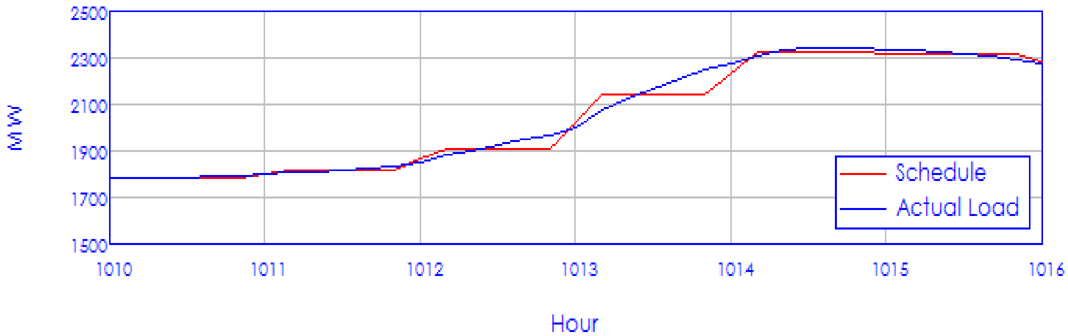


Figure 7: Hourly schedule with top-of-the-hour "ramp".

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.

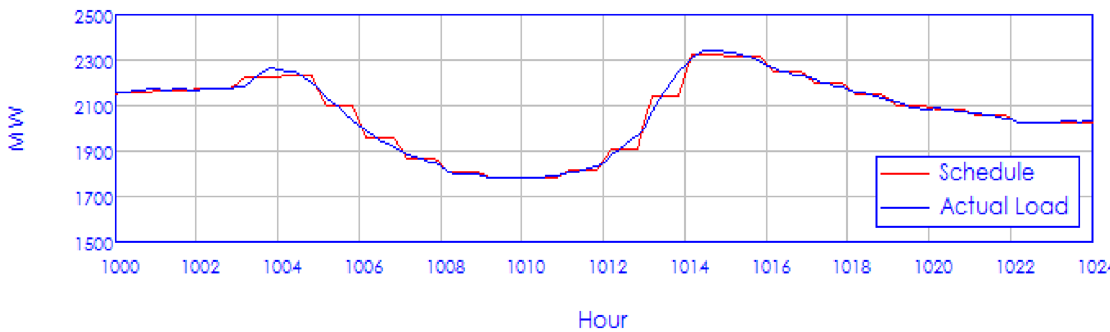


Figure 8: "Flat" hourly schedules as the basis for computing load following requirements

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.

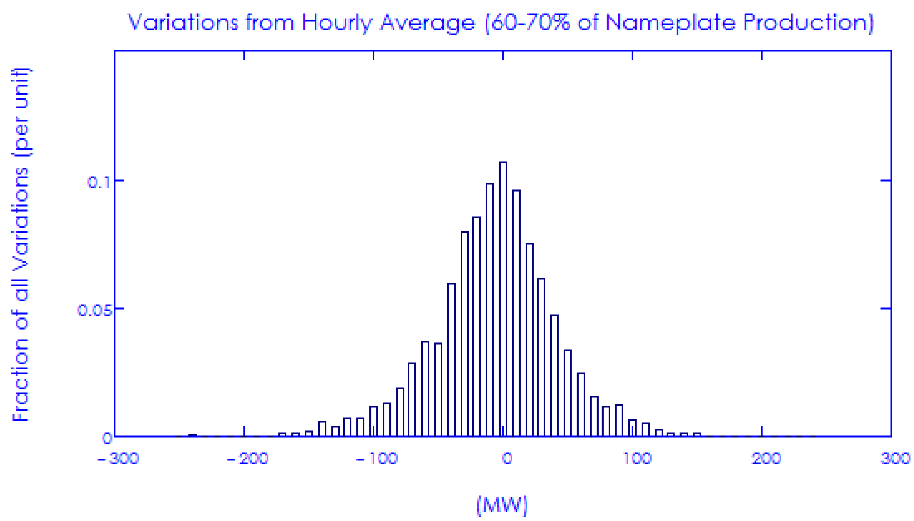


Figure 9: Variations from hourly average – Tribal Wind scenario

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.

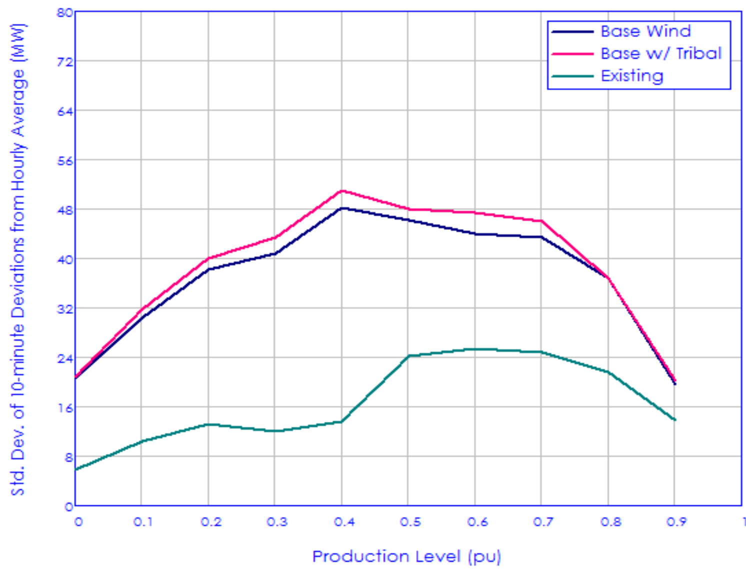


Figure 10: Standard deviation of ten-minute deviations from hourly average for three wind scenarios. Values are computed for production deciles.

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.

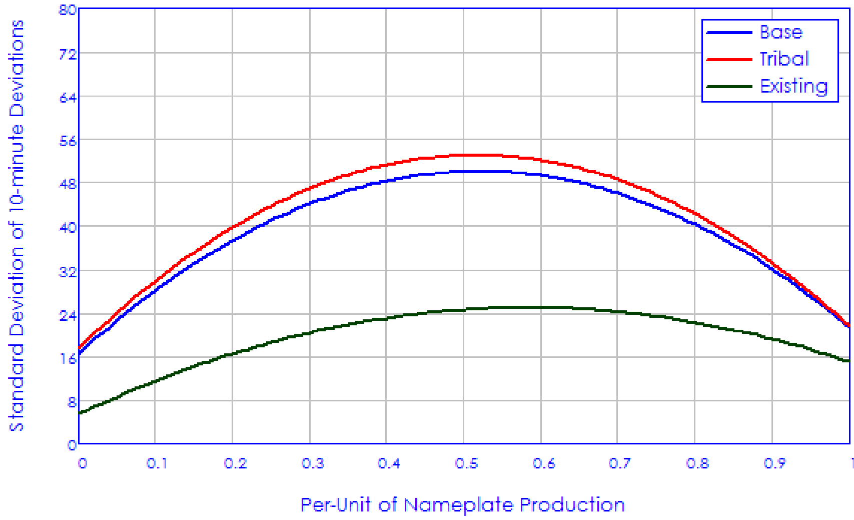


Figure 11: Approximation of curves from Figure 11with quadratic expressions; vertical axis in MW. All three wind scenarios shown.

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.

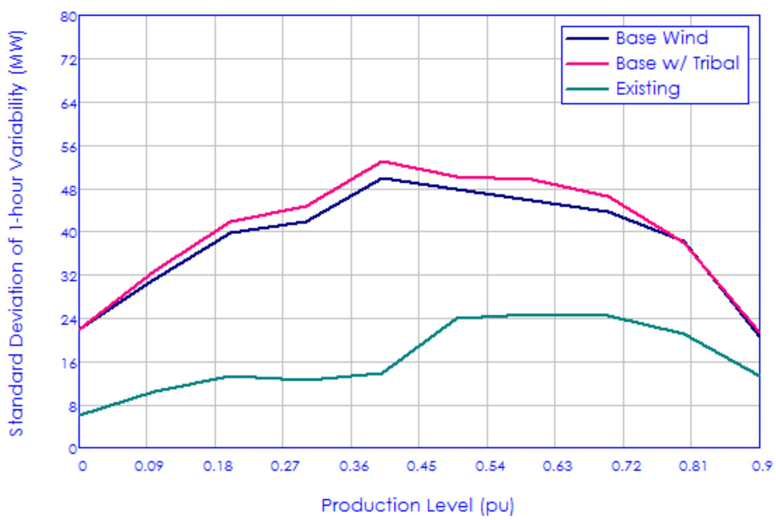


Figure 12: Standard deviation of hour-to-hour average production changes, i.e. persistence forecast "error" expectation. All three wind scenarios shown

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

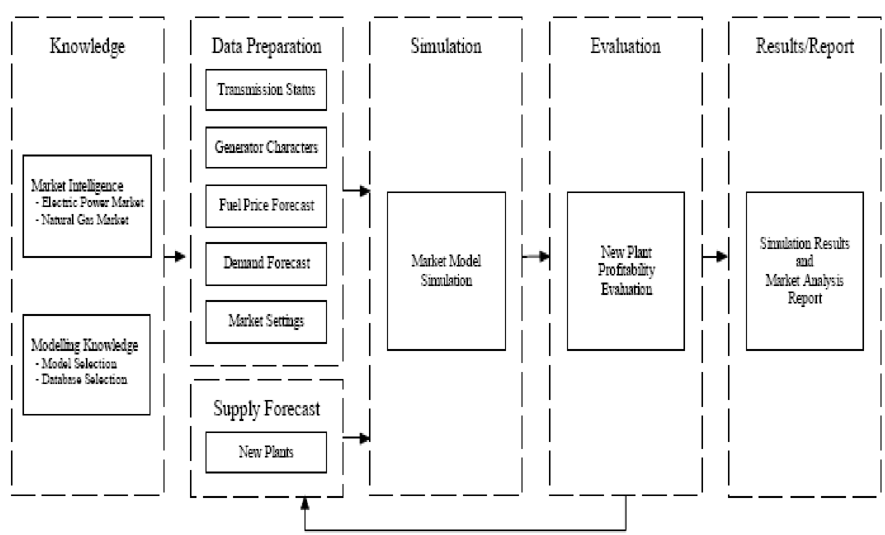
Transmission Planning Documents

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:

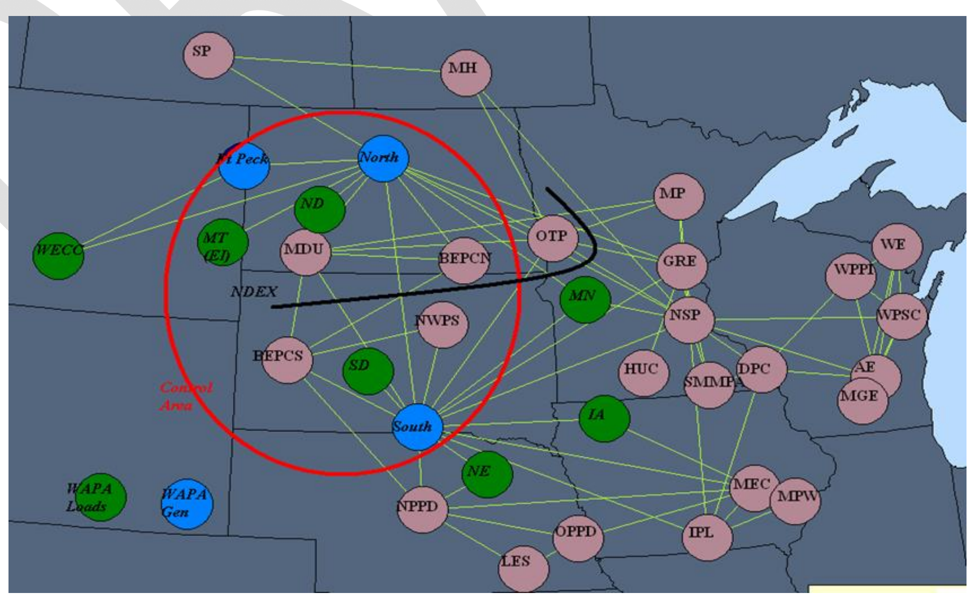
- ***Public Data Sources Relied Upon in Developing Ventyx's Simulation Data***
  - Platt's Energy Advantage
  - Ventyx EnergyVelocity
  - NERC, Energy Company and ISO websites
  - North American Electric Reliability Council (NERC) Electric Supply and Demand (ES&D) reports
  - Trade Publications such 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.

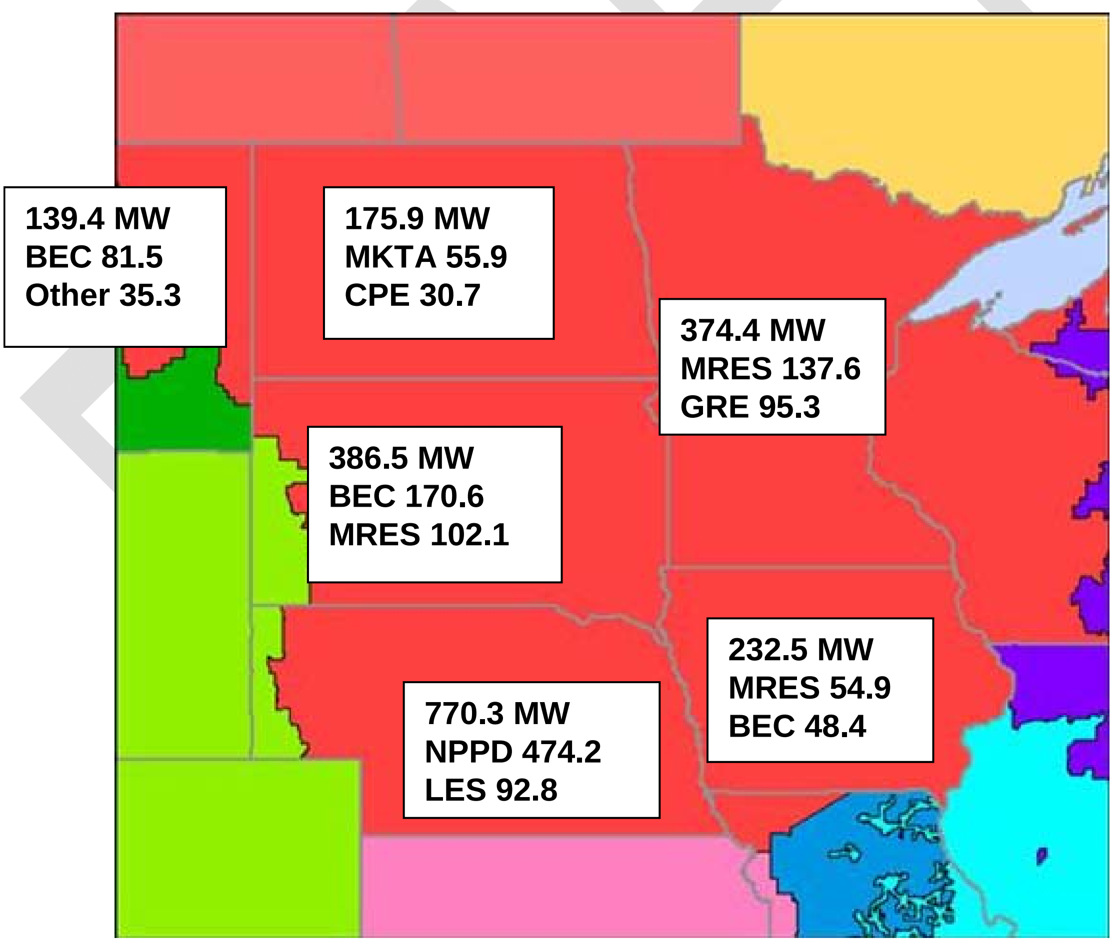
The market footprint used in this study focuses primarily on the upper Midwest, and is illustrated below in Figure G-2:



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

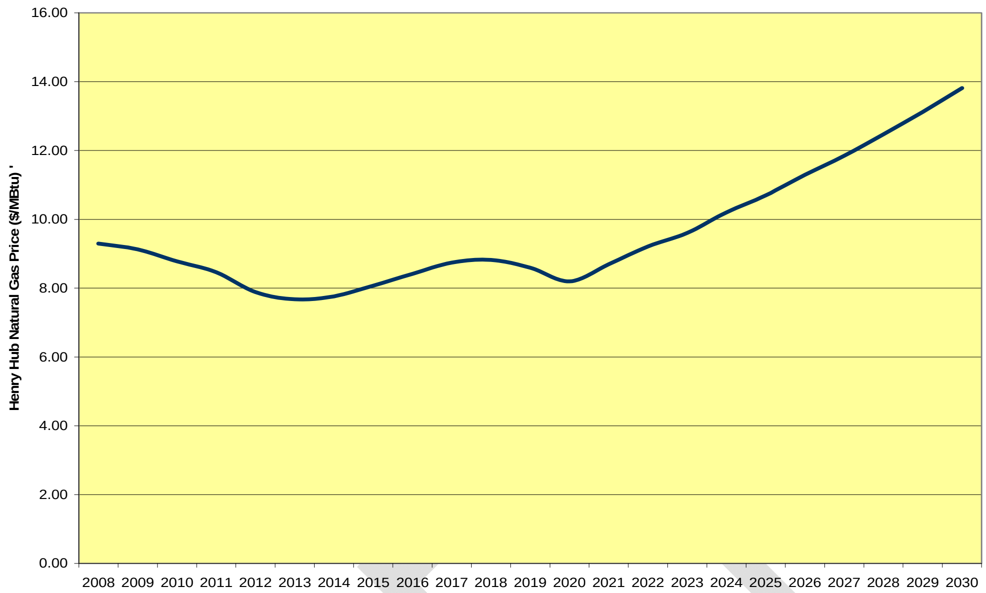
Table G-2 lists the new "generic" wind resources included in the study in the broader geographic region. In addition to those quantities, proposed non-tribal wind resources in the Western's Balancing Area were also included in the study.

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

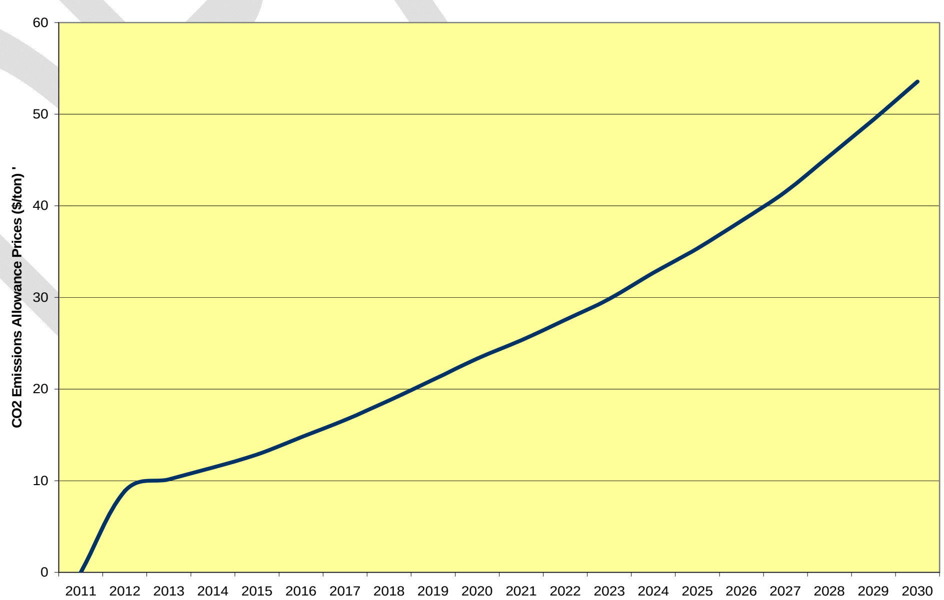
In developing the market simulations, the forecast price of natural gas is a key input assumption. Natural gas-fueled generators tend to set market clearing electricity prices during on-peak periods in the upper Midwest. Figure G-4 illustrates the natural gas price forecast at Henry Hub. Basis differentials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

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