FINAL REPORT

WIND POWER

WARM SPRINGS RESERVATION TRIBAL LANDS

DOE GRANT NUMBER DE-FG36-07GO17077

SUBMITTED BY

WARM SPRINGS POWER & WATER ENTERPRISES

A CORPORATE ENTITY

OF

THE CONFEDERATED TRIBES

OF WARM SPRINGS

WARM SPRINGS, OREGON

Submittal Date: March 2009

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Notice

In the preparation of this report, and the opinions and recommendations that follow, HDR has made forward-looking statements including information concerning possible or assumed future results of operations of the proposed facility. HDR has used and relied upon certain information and assumptions provided by sources that HDR believes to be reliable. Although HDR believes that these forward-looking statements are based on reasonable assumptions, forward-looking statements are subject to numerous factors, risks, and uncertainties that could cause actual outcomes and results to be materially different than projected. Readers should not place undue reliance on forward-looking statements. HDR cannot give any assurance that any of the events anticipated by any forward-looking statement will occur, or if they do, what impact they will have on the project. Therefore, the actual results can be expected to vary from those estimated to the extent that actual future conditions vary from those assumed by us or provided to us by others.

Executive Summary

Warm Springs Power and Water Enterprises (WSPWE) is a corporate entity owned by the Confederated Tribes of the Warm Springs Reservation, located in central Oregon. The organization is responsible for managing electrical power generation facilities on tribal lands and, as part of its charter, has the responsibility to evaluate and develop renewable energy resources for the Confederated Tribes of Warm Springs.

WSPWE recently completed a multi-year-year wind resource assessment of tribal lands, beginning with the installation of wind monitoring towers on the Mutton Mountains site in 2003, and collection of on-site wind data is ongoing. The study identified the Mutton Mountain site on the northeastern edge of the reservation as a site with sufficient wind resources to support a commercial power project estimated to generate over 226,000 MWh per year. Initial estimates indicate that the first phase of the project would be approximately 79.5 MW of installed capacity.

This Phase 2 study expands and builds on the previously conducted Phase 1 Wind Resource Assessment, dated June 30, 2007. In order to fully assess the economic benefits that may accrue to the Tribes through wind energy development at Mutton Mountain, a planning-level opinion of probable cost was performed to define the costs associated with key design and construction aspects of the proposed project. This report defines the Mutton Mountain project costs and economics in sufficient detail to allow the Tribes to either build the project themselves or contract with a developer under the most favorable terms possible for the Tribes.

This opinion of probable cost was performed to support the development of the Mutton Mountain wind project. The costs and risks associated with all aspects of the proposed project layout, including access roads, electrical system, turbine foundations, tower and turbine erection, and environmental impacts, were estimated in order for the Tribes to be in a position to make informed decisions regarding project economics and benefits. This opinion of probable cost was developed to support project financing.

In the process of developing the opinion of probable cost, several tasks were completed. A conceptual design and opinion of probable cost was developed, along with assumptions about fixed and variable costs. A project development plan was developed. Ownership options were evaluated, sources of additional funding were identified, and risks and mitigation strategies were assessed.

An economic pro forma model was developed to estimate economic performance of the proposed project, based on the opinion of probable cost for the 99 MW layout – the full characterization of the maximum capacity of the region, as determined by team meteorologists. Results of the economic model showed that removing low-performing turbines from the design would improve overall per-MW revenues of the project. The economic modeling results show that estimated returns on investment may be more attractive for a 79.5 MW facility, consisting of 53 turbines, at 1.5 MW each. Based on this modified design and cost analysis, there are now several steps that can be taken to minimize development risk, and potentially improve estimated economic returns. This should be the near-term focus for the project.

The economic analysis revealed that there are four factors with the strongest influence on the economic performance of the project: turbine price, capacity factor, power sale price, and availability of grants and incentives. If the recommended price values for each of these variables cannot be obtained, this would have the greatest impact on the attractiveness of the development opportunity. These can be considered the "deal-breaker" variables. The economic model should be updated as project development milestones are reached, to ensure that overall estimated performance remains attractive, as detailed design is developed and cost estimates are refined.

Recommended next steps:

- Perform Geotechnical Investigations
- Perform Environmental Studies and Obtain Permits
- Obtain Turbine Supply Agreement
- File Interconnection Application
- Negotiate Power Purchase Agreement
- Develop Financing Plan
- Select Construction Firm or Firms
- Detailed Civil Design
- Detailed Electrical Design

First, geotechnical investigations, environmental studies, and permitting should be undertaken to minimize project development risks. This will minimize uncertainty regarding civil engineering costs and maintenance access, and uncertainty regarding potential environmental constraints.

Second, WSPWE should pursue a turbine supply agreement. Reducing turbine cost by $200/kw from the base case cost assumed in the economic model may increase the project returns by an additional 2%.This would also likely increase the amount of PTC equity investment available per turbine.

In parallel, negotiations regarding potential power purchase agreements (PPA) should be undertaken and interconnection applications should be filed. Strong regulatory drivers (for example the Oregon Renewable Portfolio Standard) may mean this price or higher could be obtained. In addition, if the power can be wheeled to California, through proposed transmission expansion projects), the renewable power would have a higher value in that high demand market. Increasing the electricity sale price by 13% may increase the project returns by over 2%.

Fourth, a financing plan should be developed including identification of a financial advisor and legal counsel, and identification of partners to take advantage of both New Market Tax Credit and Production Tax Credit[1]. This financing plan should include a detailed list of funding opportunities and deadlines, most notably those included in the American Recovery and Reinvestment Act of 2009. This stimulus package could provide substantial grant funding or loan guarantees for the Project. This bill was just signed into law at the time this report is being finalized; therefore, the full extent of the grants and loans available for this type of project are not yet defined. However, there will likely be substantial opportunities. Grants of $50M or $100M may improve the project returns by between 4-9%, respectively. Enhanced debt with a lower interest rate could also increase returns (by about 1-2%) for equity partners by reducing the interest payments.

If all of these improvements were made, the after tax return may be around 12-15%, which would be more attractive to potential equity investors. After working to improve the estimated return on investment and assessing and mitigating high risk project development factors (especially legal factors[2]), the project team should move forward with the next steps for development.

The opinion of probable cost outlined in this report was developed for the proposed 99 MW array to characterize the maximum capacity of the site. Economic analysis showed that downsizing the array to 79.5 MW would improve the overall performance of the facility. For purposes of the economic analysis, it was assumed that most costs would scale roughly proportionally to project size. The methodologies used to develop the opinion of probable cost for the original 99 MW array are described in the following chapters of this report. Detailed cost information about this project are considered sensitive and confidential material. This information has been removed from this document for public release.

[1] Or obtain grants from the DOE in lieu of the PTC under the new legislation enacted under the American Recovery and Reinvestment Act of 2009.

[2] The team will most likely have to work with multiple attorneys with different areas of expertise to see the project through development. Specialized contracts are needed for power purchase agreements, turbine procurement, project financing, and land use. The Tribes may also need to hire attorneys who specialize in permitting and environmental compliance. In addition, the Tribes should consult attorneys experienced in corporate and tax law to make sure that the assets are protected should the project not perform as expected.

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Project Background

Warm Springs Power and Water Enterprises (WSPWE) is a corporate entity owned by the Confederated Tribes of the Warm Springs Reservation, located in central Oregon. The organization is responsible for managing electrical power generation facilities on tribal lands and, as part of its charter, has the responsibility to evaluate and develop renewable energy resources for the Confederated Tribes of Warm Springs.

WSPWE recently completed a four-year wind resource assessment of tribal lands. The study identified the Mutton Mountain site on the northeastern edge of the reservation as a site with sufficient wind resources to support a commercial power project estimated to generate over 226,000 MWh per year. Initial estimates indicate that the first phase of the project would be approximately 79.5 MW of installed capacity.

Project Location

Showcasing most of the Pacific Northwest's natural wonders, the Warm Springs Reservation includes Alpine lakes, pristine rivers, deep canyons and vistas of high desert and volcanic peaks. Over half the reservation is forested with the remainder primarily range land. Reservation lands extend from the summit of Oregon's Cascade Mountains and snowcapped Mt. Jefferson at 10,497 feet east to the Deschutes River's elevation at 1000 feet, with the Metolius River and Lake Billy Chinook forming the southern boundary.

Project Description

This Phase 2 Opinion of Probable Cost study expands and builds on the previously conducted Phase 1 Wind Resource Assessment. In order to fully assess the economic benefits that may accrue to the Tribes through wind energy development at Mutton Mountain, a planning-level opinion o fprobable cost study was completed to define the costs associated with key construction aspects of the proposed project. This report defines the Mutton Mountain wind project costs and economics in sufficient detail to allow the Tribes to either build the project themselves or contract with a developer under the most favorable terms possible for the Tribes.

This opinion of probable cost was developed to support the development of the Mutton Mountain wind project. The costs and risks associated with all aspects of the proposed 99 MW project layout, including access roads, electrical system, turbine foundations, tower and turbine erection, and environmental impacts, were estimated in order for the Tribes to be in a position to make informed decisions regarding project economics and benefits. This opinion of probable cost was developed to support project financing. The feasibility study contains a proposed business plan for the proposed wind energy facility at Mutton Mountain. The information in this study will support negotiations over power sales agreements, engineering contracts, and construction contracts.

This study also contains an analysis of the risks associated with each task in the business plan, and proposed mitigation strategies for managing these risks. This risk analysis is included in order to provide the Tribal Council with an accurate estimate of the range of possible development costs.

These four primary goals guided the development of this report:

1. Complete a preliminary conceptual design sufficient to define the costs and risks associated with key elements of project construction. This scope of work does not include detailed project engineering. However, it does include conceptual design and development of specifications in sufficient detail to provide a planning level opinion of probable cost.
2. Prepare opinion of probable cost of capital requirements and operation and maintenance costs for the initial phase of the Mutton Mountain project based on the conceptual design and alternative transmission routes.
3. Identify issues where additional engineering or geotechnical investigations are needed to define the project design and estimate the cost to complete additional engineering or geotechnical studies that may be required to support project financial documents.
4. Prepare a detailed project description and conceptual design document that can be used in a subsequent development phase for:

    a. Preparing the project description documents for the National Environmental Policy Act analysis

    b. Preparing the specifications documents for an engineer-procure-construct contract for detailed engineering and construction of the Mutton Mountain project

    c. Preparing the project pro forma and risk analysis documentation required for project financing or joint development agreements

    d. Negotiating the terms and conditions for the project's power sales agreement and interconnection agreements.

Scope

The cost analysis for the Mutton Mountain project focused on several key aspects of the development that need more detailed development in order to realistically estimate the total cost of the facility. The following key aspects of the project design and development are addressed in this report:

- Access road improvements and new road construction required for development
- Transmission line route cost analysis for the two alternative routes
- Substation improvement requirements for power export
- Environmental assessment and licensing.

This document outlines the work performed under this grant. The economic analysis shows that the proposed project presents a commercially attractive business opportunity, which merits further investigation, leading towards project development. The next steps for investigation and development are outlined in Task 8: Project Development Plan.

Chapter 1: Refine Initial Turbine Placement

Task 1 Description

A conceptual 99 MW facility layout was developed to determine the maximum turbine-bearing capacity of the site. HDR worked with the WSPWE GIS department to combine updated geological and topographical data with updated meteorological data to create a full characterization of the region, shown in the map in Appendix D. HDR and meteorologist V-Bar refined the locations of the 66 wind turbines, based on review of the preliminary wind turbine layout from the Phase 1 study. The annual energy production estimate was updated by V-Bar in 2008, incorporating the additional months of data collected from the on-site monitoring towers since the 2007 Phase 1 report. The updated energy production estimate for the 99 MW array is included as Appendix B to this report.

Upon analyzing the results of the cost study and the economic model, it was determined that the projects economic performance could be improved by removing outlying low-performing turbines, thereby increasing the per MW energy production of the downsized 79.5 MW array.

Task 1 Assumptions

GE 1.5 xle wind turbines were assumed for the cost estimating purposes of this study. GE Energy has long been the predominant manufacturer of wind turbines in the United States; capturing 44% of the market share in 2007 (see Table 2 below). GE provided a budgetary quote and turbine and tower erection manuals to support the cost estimating effort. This budgetary quote is included as Appendix A to this report. For energy production estimates, turbine delivery, foundation design, and tower and turbine erection, GE performance characteristics were assumed as representative. In later stages of development, the turbine manufacturer may be confirmed or changed, to ensure the most favorable equipment price, warranty, and contract terms for delivery and operations and maintenance.

Table 1: Annual turbine installations in US, by manufacturer.

Manufacturer	Turbine Installations (MW)		
	2005	2006	2007
GE Wind	1,433	1,146	2,342
Vestas	700	463	948
Siemens	0	573	863
Gamesa	50	50	574
Mitsubishi	190	128	356
Suzlon	25	92	197
Clipper	2.5	0	47.5
Nordex	0	0	2.5

Other	2	2	0
Total	2,402	2,454	5,329

Source: National Renewable Energy Lab. Annual Report on US Wind Power Installation, Cost, and Performance Trends: 2007.

Task 1 Methodology

Turbine locations were selected by V-Bar meteorologists, based on wind data collected from the on-site monitoring towers, topographic data, and feedback from the team's civil engineers regarding accessibility of turbine sites for construction. Turbine locations were revised due to road and construction accessibility.

Access roads to several proposed wind turbine locations were found inaccessible based on the terrain and infeasible earthwork that would be required to provide access. Proposed wind turbines 7, 8, 9, 10, 22, 23, 27, 45, 49, 50, and 59 were found to be inaccessible. Alternative wind turbine locations were developed through coordination with the meteorology subcontractor (V-Bar). These revised wind turbine locations were named with an "A" after the wind turbine number they replaced. The revised wind turbine locations are 7A, 8A, 9A, 10A, 22A, 23A, 27A, 45A, 49A, 50A, and 59A. The proposed access roads were designed to accommodate access to all the revised wind turbine locations. This process is further described in Task 4: Road Improvement Review, and in Appendix E.

No major conflicts were identified with tribal property allotments or sensitive wildlife habitat at this preliminary stage of project development. See maps of tribal allotments and wildlife habitat in Appendices C and D to this report. Turbine locations may be subject to further revision based on geotechnical, environmental, or electrical constraints identified in later phases of development and detailed design.

The turbine locations shown in Figure 2 were used for the 99 MWconceptual design developed in this study.

Upon completion of the opinion of probable cost for the proposed maximum 99 MW array, an economic pro forma model was developed to estimate economic performance of the 99 MW facility. The economic model, developed in Task 9, is described in Chapter 8 of this report. One round of economic analysis was completed based on the opinion of probable cost for the 99 MW layout – the full characterization of the maximum capacity of the region, as determined by team meteorologists. Results of this initial economic model showed that overall per-MW revenues of the project may be significantly improved by removing low-performing turbines from the design, and assuming capital costs would be reduced roughly proportionally. As a result, it was assumed that outlying turbines, with estimated net capacity factors below 25%, would be eliminated from the modified 79.5 MW array. This includes turbines numbered 1-7, and 45-50, as can be seen in Appendix J: Turbine Coordinates and Estimated Capacity Factors. This raised the estimated overall project capacity factor from 30.7% to 32.5%. The economic modeling results show more attractive estimated returns on investment for the modified 79.5 MW facility, consisting of 53 turbines, at 1.5 MW each. In later phases of project development, more detailed meteorological and engineering analysis will be performed to further characterize the modified 79.5 MW array.

Task 1 Findings

Wind turbine specification and array design were based on analysis of the wind data. Major findings are outlined below.

Long-term mean annual wind speed for the 99 MW array: Mean annual wind speed for the turbine array was estimated to be 6.7 m/s at 80m hub height. Because the mean annual wind speed is below the design threshold of 8.0 m/s, the GE 1.5 xle model was specified for the lower wind regime.

Maximum gust: For the entire period of record, the maximum hourly mean wind speed was 27.1 m/s, and the 2-second peak gust was 40 m/s. As a rule of thumb, sites with peak gusts over 55 m/s are considered to pose hazards to turbine operation and maintenance, but this site's peak gust is well within the range of reasonable speeds.

Correlation to nearby long-term wind records: The energy production estimate is based on 5 years of on-site wind data, from May 2003 through June 2008. V-Bar compared this 5-year record of on-site wind speeds with the long-term records of wind speeds at nearby weather stations, to provide a long-term estimate for the site. The concurrent speeds at the Redmond and Goodnoe stations, as checked relative to their actual long-term values, were found to be identical for Redmond, and within about 1% for Goodnoe. This leads to the conclusion that the data collected at the site is representative of its true long-term wind speed. Long-term wind speeds at different heights above ground level are shown in Table 3 below.

Table 2: Predicted Long-Term Mean Annual Wind Speeds at Met Tower Locations

Level (m)	MM-1	MM-2	MM-3	MM-4	MM-5	SB
10	4.86	5.04	5.91	4.78	5.45	6.34
30	6.26	6.58	6.33	5.86	6.02	6.99
49/50	6.65		6.66	6.32		
49/50	x		6.60	6.26		
80	7.33	8.67	7.16	7.12	6.83	7.82

Turbulence intensity: Turbulence intensity values for the wind monitoring towers on this site are low to moderate, ranging from 0.07 - 0.14 in the power-producing range of speeds. Hub height turbulence will be less than these values. This low turbulence intensity will mean less wear on the turbine. Turbulence intensities range from less than 0.10 from 4 mps and above (low), to 0.10-0.15 (moderate), to above 0.15 (high). High turbulence environments cause excessive wear and tear on the turbines.

Gross capacity factor for the 99 MW array: The predicted 80-m long-term mean annual array wind speed is equivalent to a gross capacity factor of about 34% for the proposed 99 MW array. This translates to total annual energy production equivalent to 34% of what would be produced if all the turbines were operating at their maximum power rating for 8760 hours of the year. Typical commercially viable wind energy sites typically have capacity factors of 30% or above.

Losses: The following preliminary discount factors were used to convert the estimated gross capacity factor to the net capacity factor:

- Turbine availability losses (due to operations and maintenance), 3%
- Electrical losses, 2%. This includes transformer and line losses up to the high side of the utility substation. This is a typical value. An electrical engineer will make a more exact determination in later phases of project design.
- Wake losses (estimated, based on modeling), 2.0% for the GE 1.5 xle.
- Turbulence losses, 1%. This includes high-wind hysteresis and other turbulent conditions.
- Blade contamination losses, 1%
- Icing losses, 2%, typical for this part of the U.S.

The total discount is obtained from the product of the individual "efficiencies" (100% minus the loss) for each discount factor. For the Mutton Mountains site, the total discount is estimated at 10.22% for the GE 1.5 xle.

The resulting long-term mean annual net capacity factor projection for the 66-turbine GE 1.5 xle array is thus 30.7%. This value represents the P50, or base-case confidence level. Statistically, this confidence designation means that for any given year, there is a 50% chance that year's energy production will be higher than this estimate, and a 50% chance that it will be lower.

Locations of the on-site wind monitoring towers and updated wind turbine locations are shown in Figures 1 and 2 below.

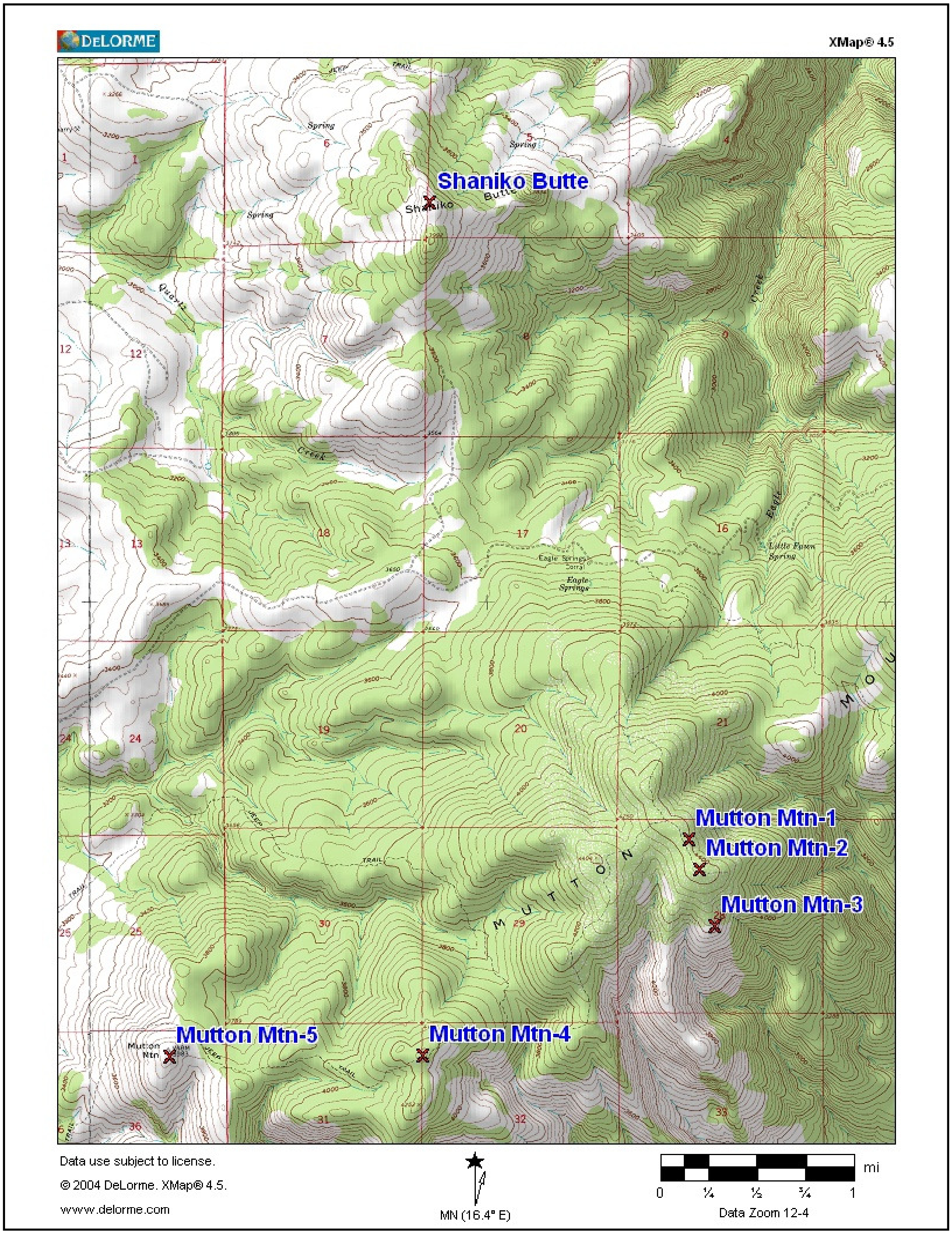

Figure 1. Locations of wind monitoring towers on site

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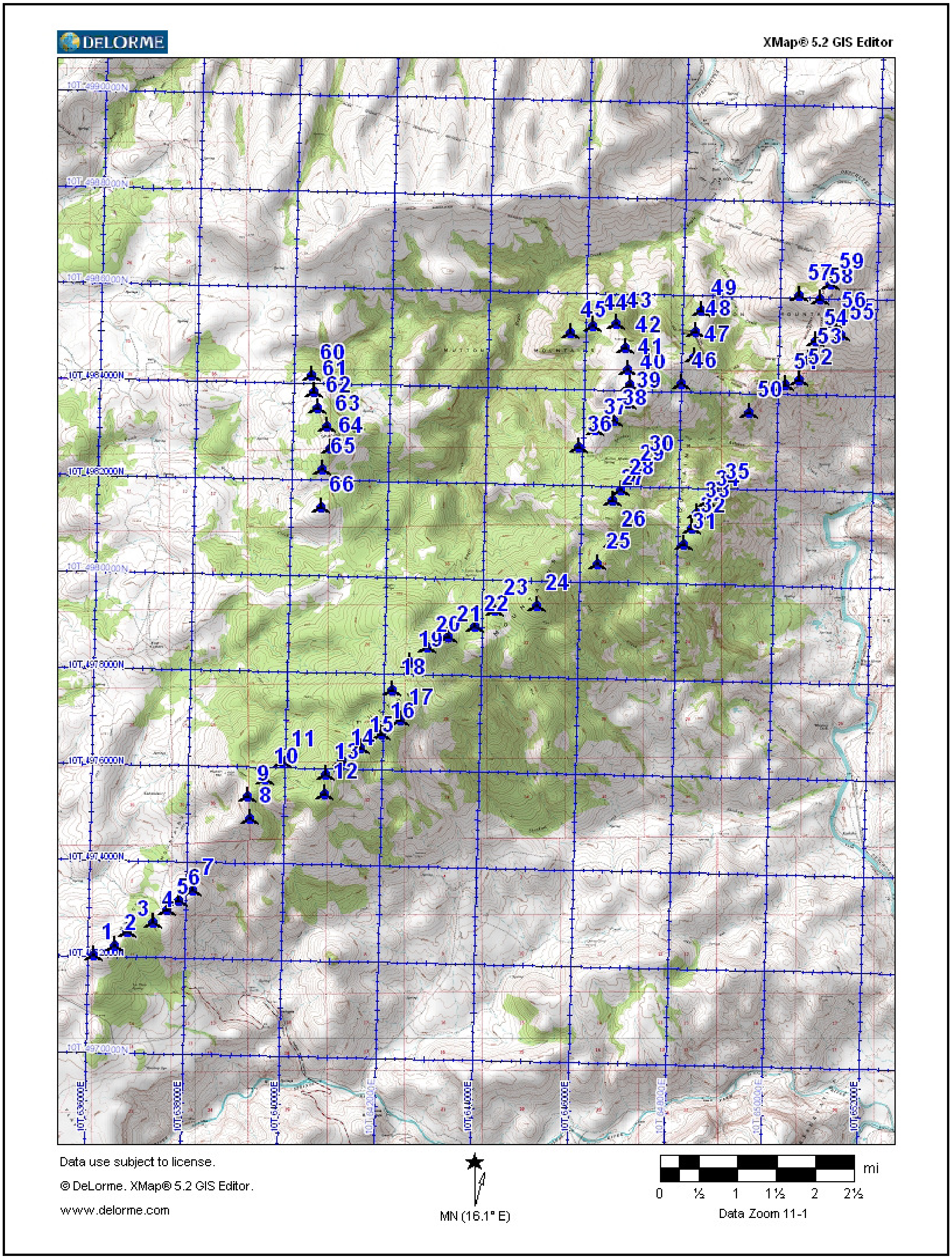

Figure 2. Proposed locations of 66 GE 1.5 MW xle wind turbines for 99 MW array

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Chapter 2: Internal review of maps, prior studies, GIS data

Task 2 Description

Turbine coordinates were mapped through collaboration among V-Bar, HDR, and the Tribal GIS department. Turbine locations were overlaid with data such as topography, existing roads and existing electrical infrastructure, vegetation and wildlife data, and parcel ownership. Team meteorologists, engineers, and environmental specialists reviewed these maps and GIS data, for use in their respective tasks. Data format was adapted for compatibility with software used by different team members. The GIS data was used by the civil and electrical engineering teams as the basis for computer-aided design, as described in Tasks 4 and 6.

Task 2 Findings

Tribal allotments were identified, and wildlife habitat was identified. It was confirmed that no turbines will be located on allotments belonging to tribal members (see Appendix C). Turbine locations were screened with respect to vegetation and wildlife populations, to make a preliminary determination that turbine locations would avoid impacts on sensitive species habitat (see Appendix D).

Chapter 3: Site Visit

Task 3 Description

The project team attended a one-day site visit for orientation to the project and to meet with Tribal staff, to establish contacts, clarify expectations and deliverables, and perform preliminary reconnaissance for their respective tasks. The site visit took place on May 23, 2008. It was attended by project managers as well as the team civil and electrical engineers and the environmental analyst.

Task 3 Activities

The team reviewed maps of the project and identified potential issues, to be addressed in each of the tasks. The project team toured the region to observe the local landscape, habitat, and geology, and to investigate potential gravel and water sources and concrete mixing sites. Inclement weather and poor road conditions prevented the project team from accessing the proposed turbine locations. Mapping requirements were discussed, contacts were identified for particular project issues, and protocols for information transfer among the parties (HDR, Elcon Associates, WSPWE, Tribal Natural Resources department, Tribal GIS department) were identified.

Task 3 Findings

Mapping and GIS data exchange requirements were developed. Potential wildlife species that may be impacted by the proposed facility were identified, and resources were identified for use in Task 7: Opinion of Probable Cost for Environmental Assessment and Permitting. Although the conditions prevented the team from accessing the proposed turbine locations, graphical renderings were developed for visualization of the proposed facility, as can be seen in figures 3 through 10 below. While touring the region, civil engineers visually inspected existing conditions and developed concept for the extent of required access road improvements.

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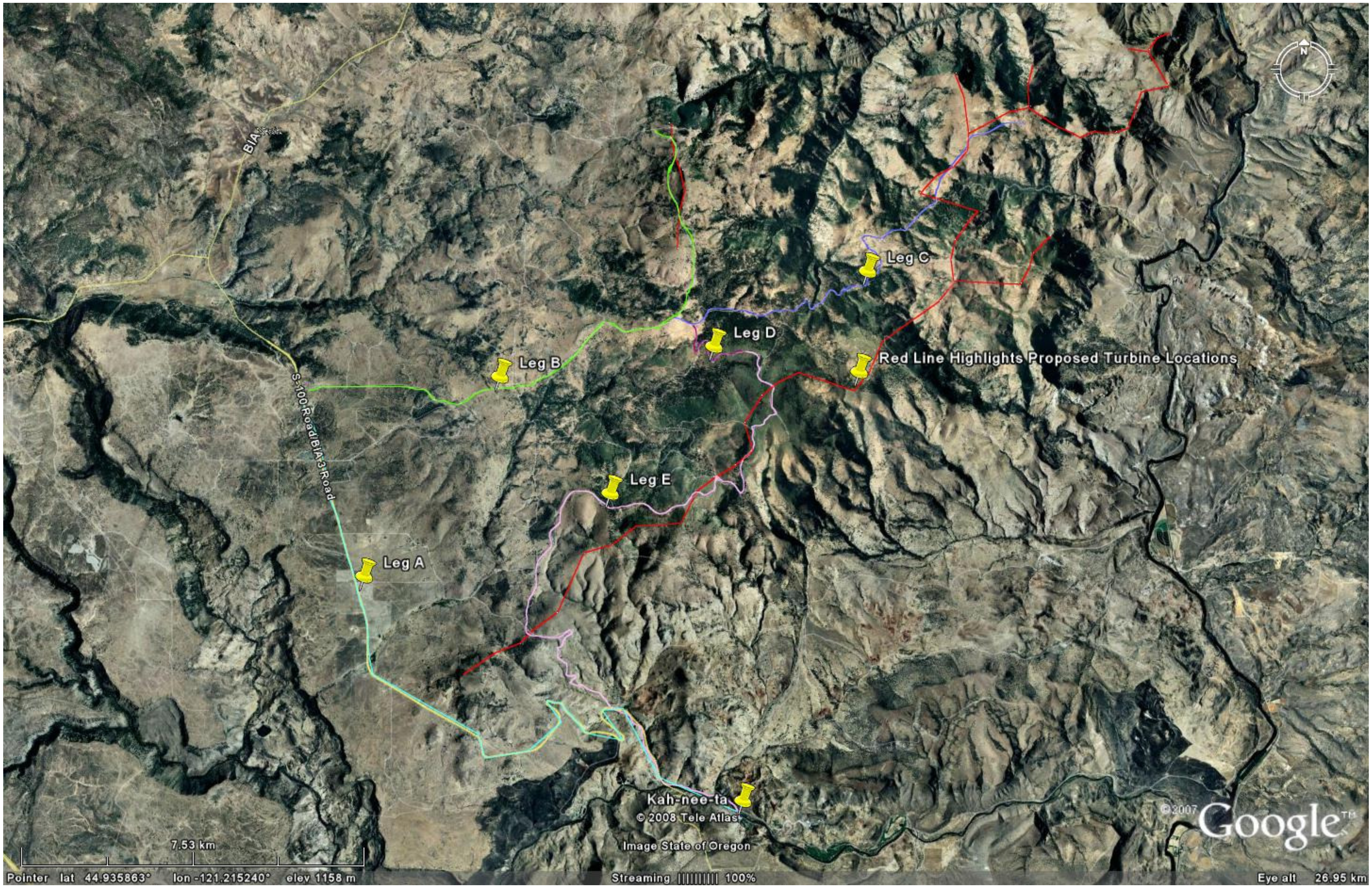

Figure 3. Tentative Route, WSPWE Wind Energy proposed facility, Mutton Mountain and Shaniko Butte.

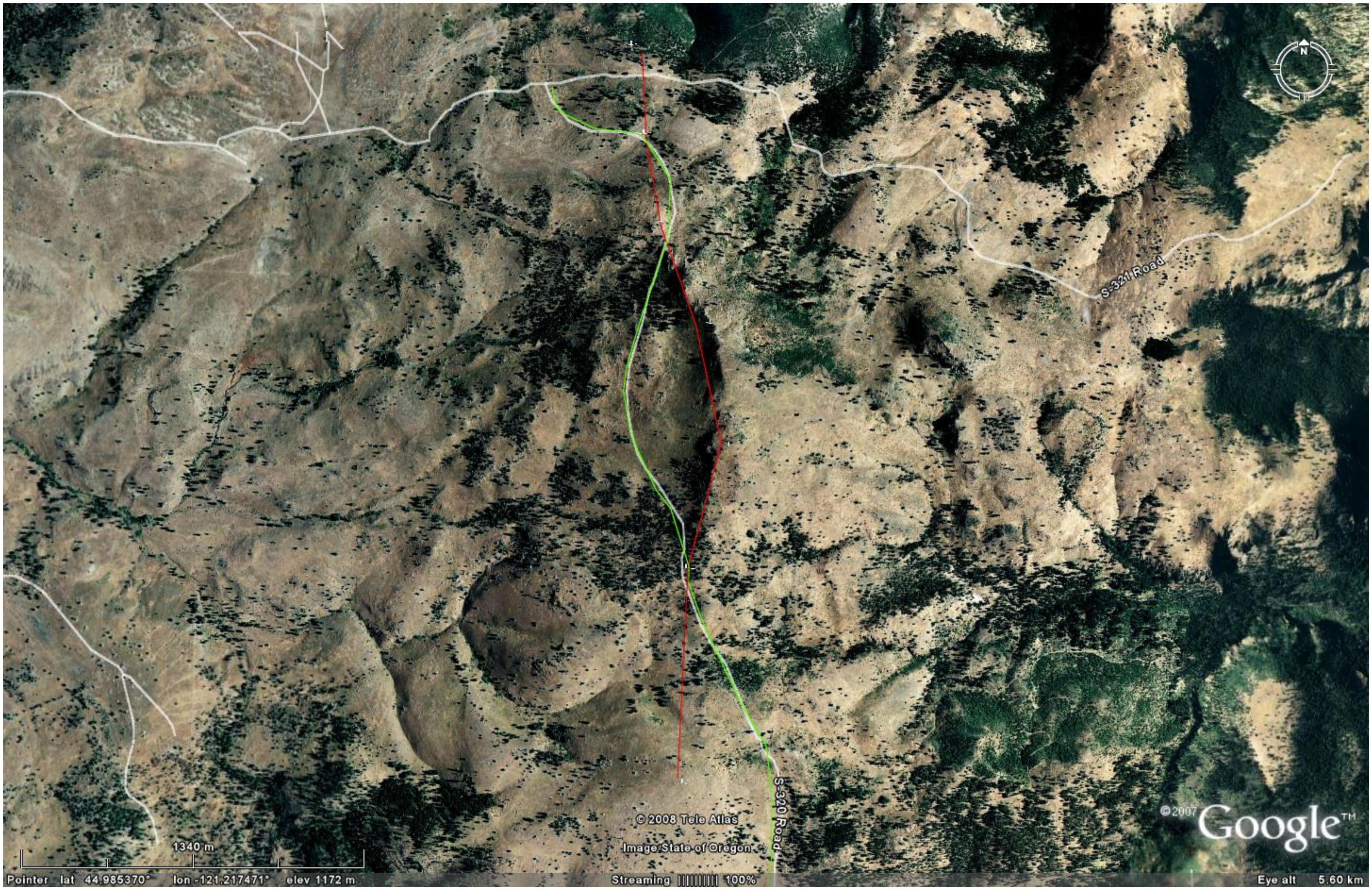

Figure 4. Leg B. Shaniko Butte. Road S-320.

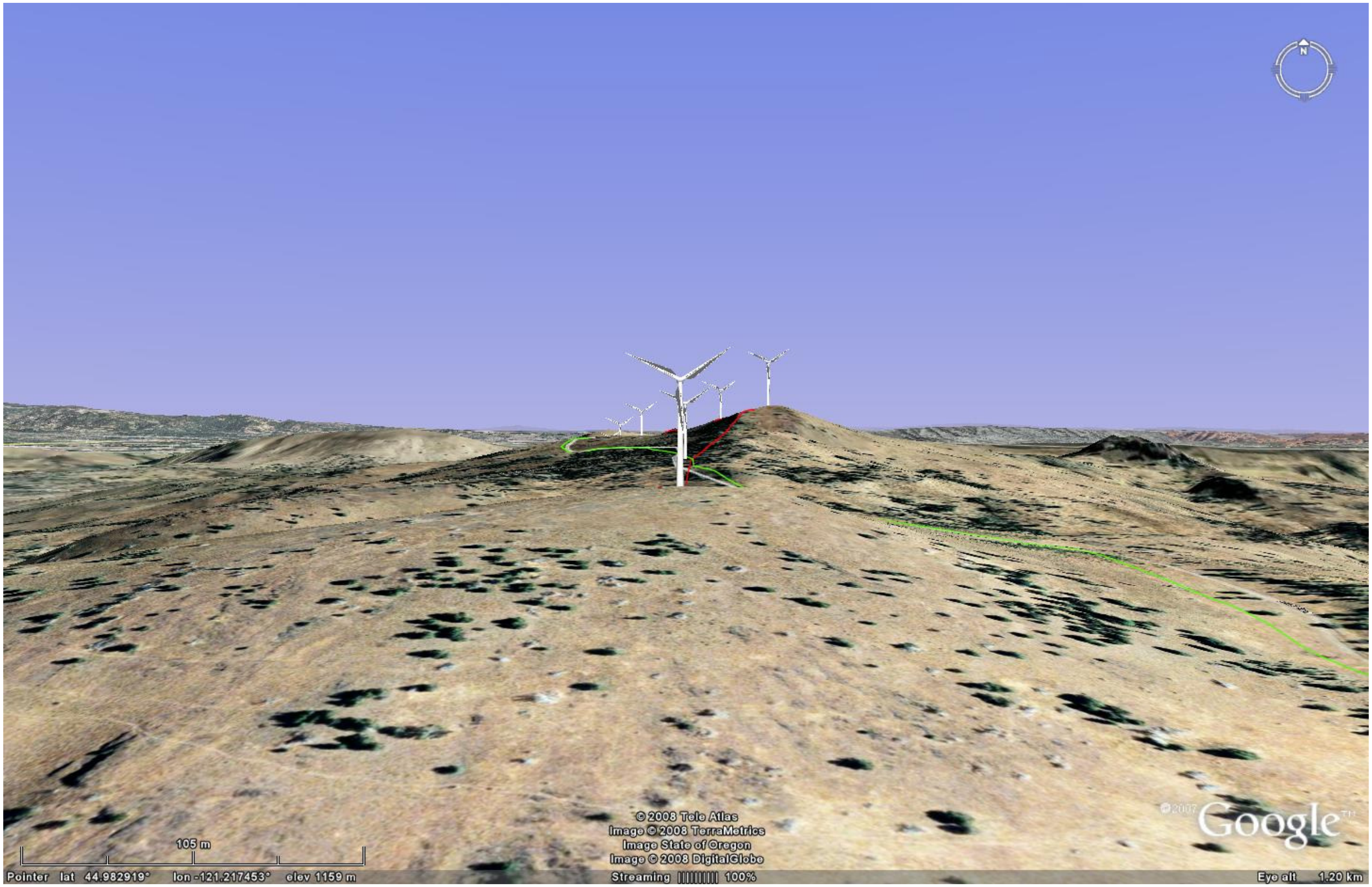

Figure 5. Leg B perspective.

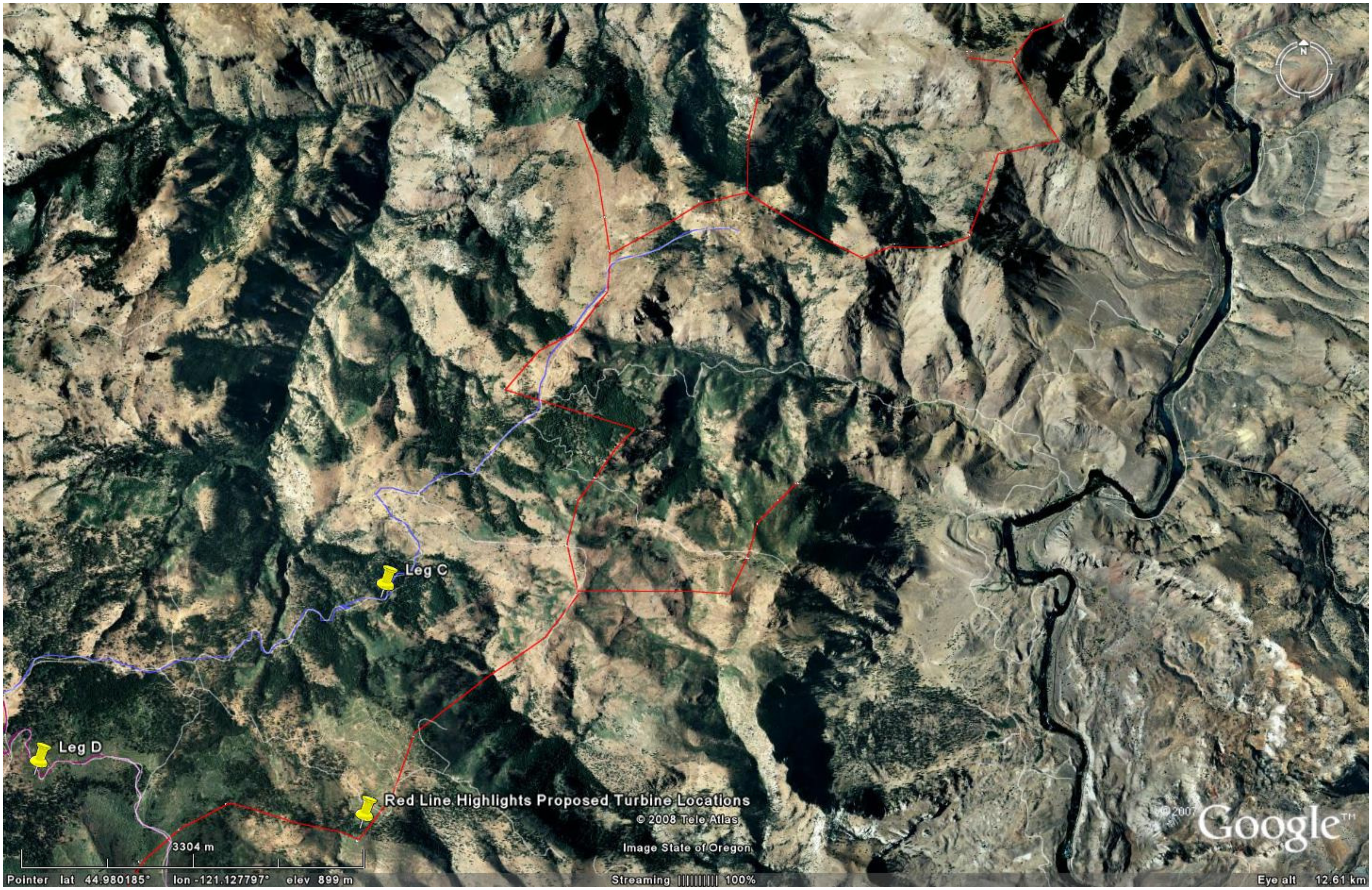

Figure 6. Leg C. Road S-390.

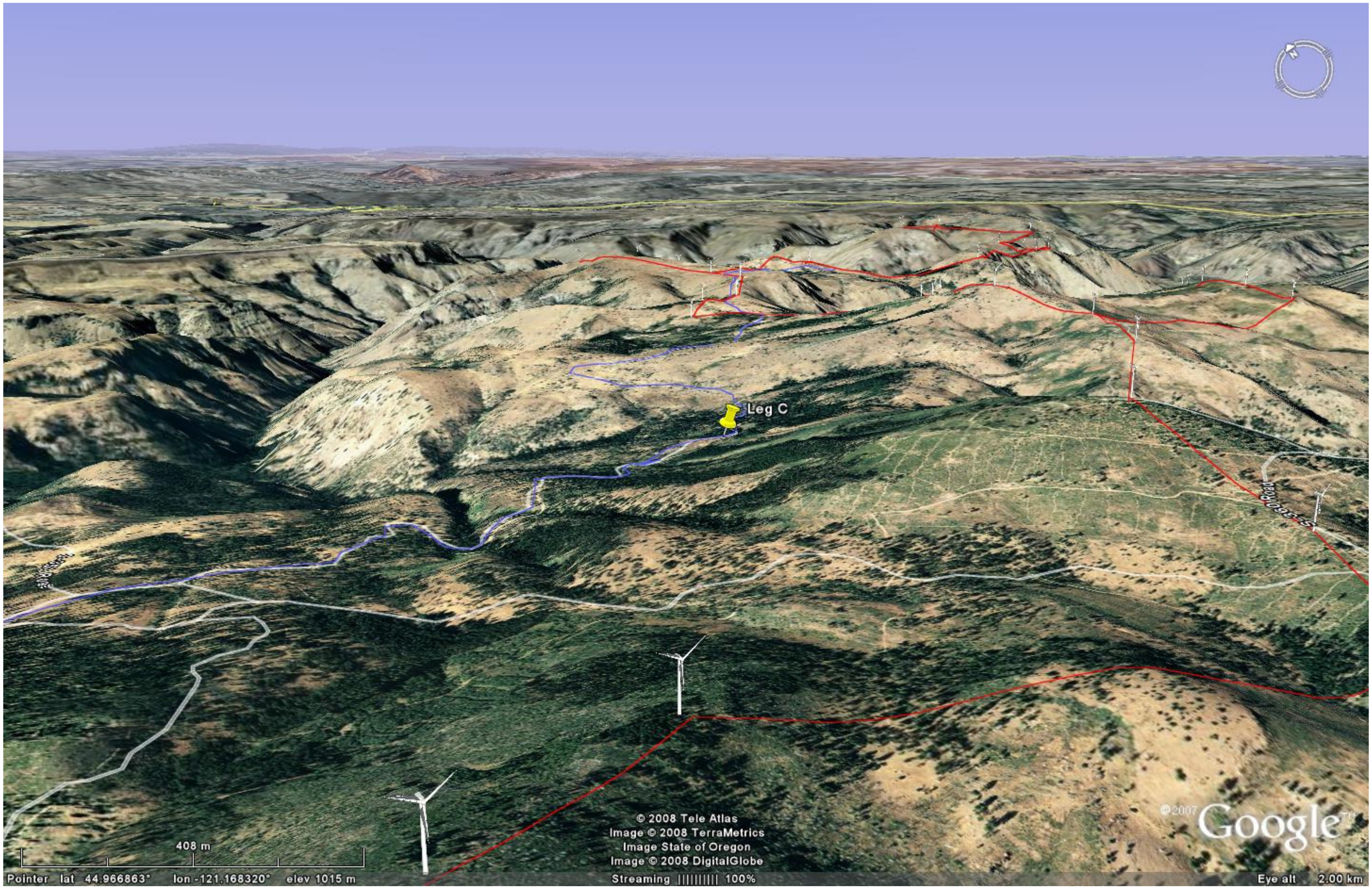

Figure 7. Leg C perspective.

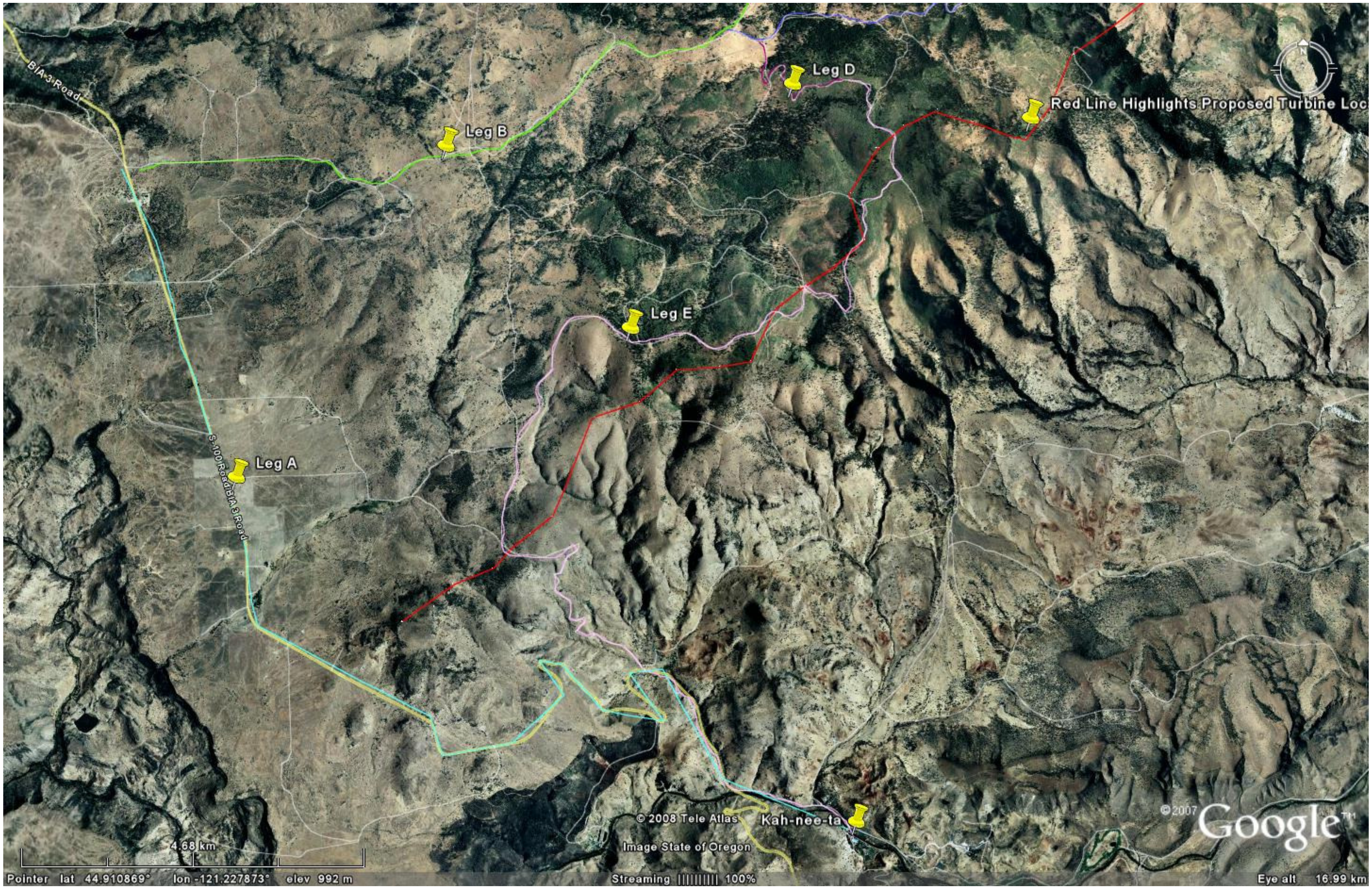

Figure 8. Leg D and E. Roads S-333, S-340, S-331, and S-111.

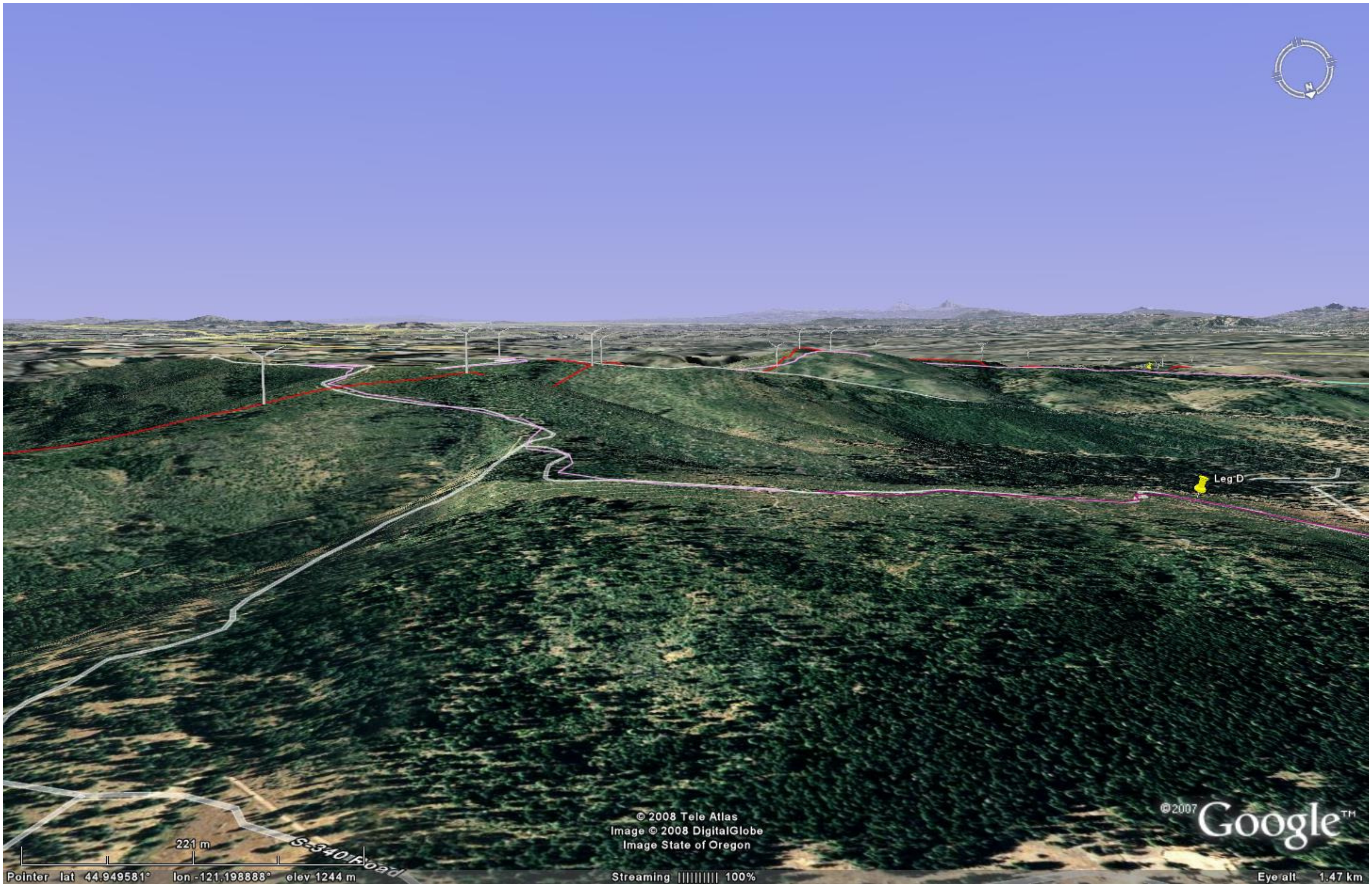

Figure 9. Leg D. Road S-333.

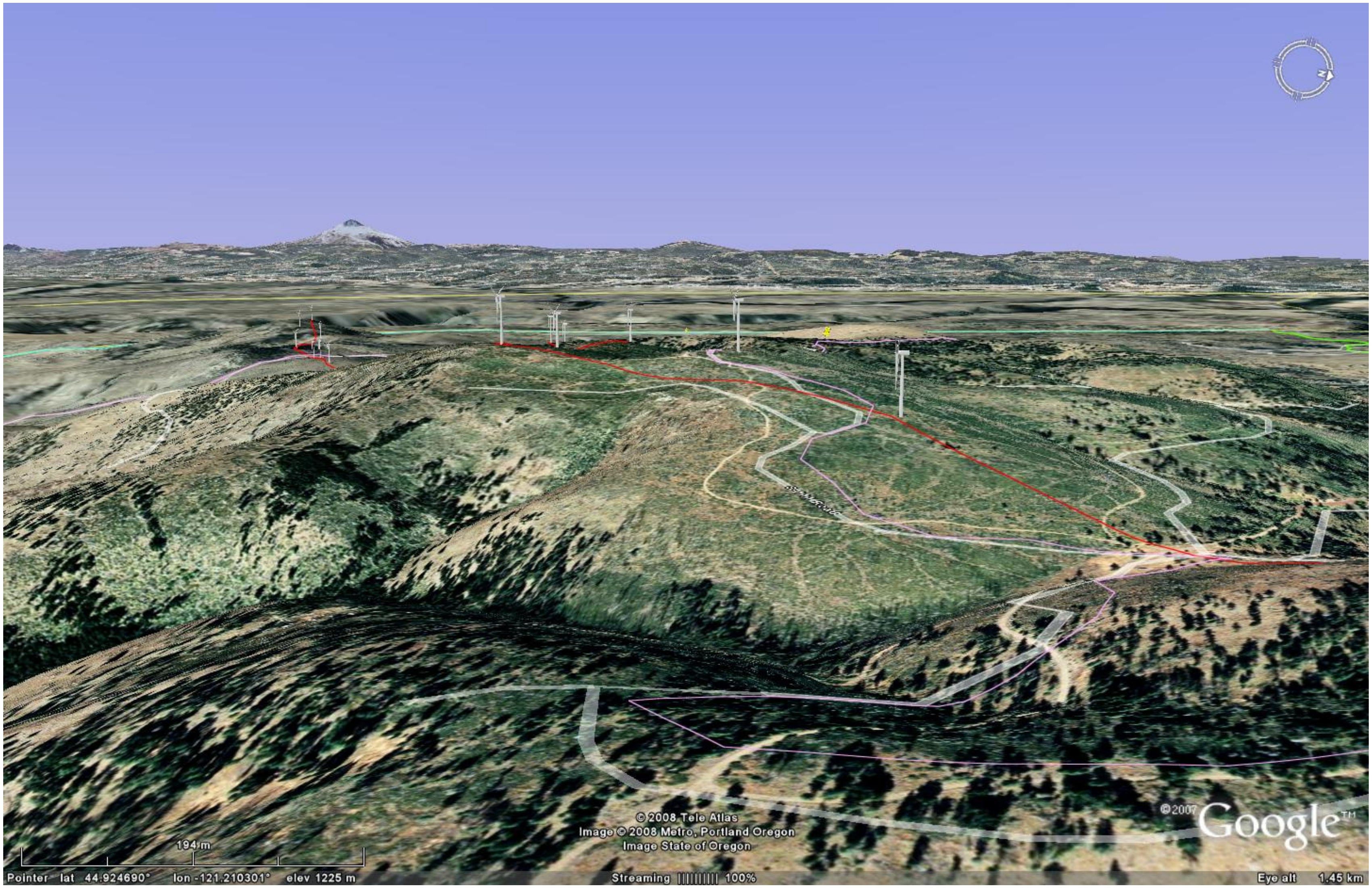

Figure 10. Leg E. Road S-111.

Chapter 4: Road Improvement Review and Opinion of Probable Cost

Task 4 Description

In Task 4 the primary and secondary access roads that would be used to support construction of the proposed 99 MW wind energy facility were identified. This chapter evaluates the improvements needed to bring the roads up to a standard that could support the construction and maintenance of the proposed wind energy facility. The road improvement costs for access and construction roads in the area were identified. Cost information is considered sensitive and confidential, and has been redacted from this document for public release.

Table 3: Opinion of Probable Cost for Road Improvements for proposed 99 MW Array

REDACTED

This chapter describes the opinion of probable cost developed to characterize the maximum 99 MW capacity of the site. Results of initial economic analysis showed that overall per-MW revenues of the project may be significantly improved by removing low-performing turbines from the design, and assuming capital costs would be reduced roughly proportionally. The final economic analysis for this report assumed that outlying turbines, with estimated net capacity factors below 25%, would be eliminated from the modified 79.5 MW array. This includes turbines numbered 1-7, and 45-50, as can be seen in Appendix J: Turbine Coordinates and Estimated Capacity Factors. The economic modeling results show improved estimated returns on investment for the modified 79.5 MW facility, consisting of 53 turbines, at 1.5 MW each. In later phases of project development, detailed design of access roadways will be performed, to further characterize the reduced scope and cost of the 79.5 MW array. The economic analysis of this report assumes that roadway costs are reduced proportionally to the reduction in project size.

The roadway findings of this report should only be used for order-of-magnitude opinion of probable costs based upon this level of accuracy. Standard estimate accuracy (e.g. Association of Cost Engineering International AACEI classification) has not been applied to this point estimate. Base mapping of higher accuracy, supplemental ground surveys, geotechnical investigations and recommendations, identification of the actual design vehicles and their performance characteristics are needed to better identify quantities, and costs, and are necessary for final design and preparation of construction documents.

Task 4 Activities

The subtasks for Task 4 are summarized below:

- Identify road requirements for wind turbine delivery.
- Identify main access route.
- Identify main staging area and civil requirements for wind turbine erection.

- Determine crane movement road requirements.
- Prepare an Opinion of Probable Cost for access road improvements.

These activities are described in detail in the following sections of this report.

Site Description

The Mutton Mountains are a complex series of ridges running north to south at elevations of about 3,800-4,000 feet above sea level. The area of interest is approximately 7 to 8 square miles of land, about 8 miles north of Ka-Nee-Tah Resort. It is estimated that 10 miles of ridgeline are available for wind turbine construction. Some of these ridgelines are forested, and some are exposed. The complex terrain and limited access roads are of primary concern for the Mutton Mountain site. Currently, the only way to access the proposed wind turbine locations is via primitive dirt logging roads.

Base Design Information

Information received from the Confederated Tribes of Warm Springs GIS Center was used for the design basis in this report. A list of project files that were received is located in Appendix E. These files were converted from a metric unit system to an English unit system. A digital terrain model with an English unit system was created based upon the data points extracted from GIS files with a metric unit system. This model was then used to perform the concept design layout of the access roads and obtain order-of-magnitude earthwork quantities.

The accuracy of the survey information used to create the GIS files is described in the email from Bret Hazell on 7/17/2008 and shown in Appendix E. This correspondence indicates that, "The accuracy of measured spot elevations should be in most cases better than +/- 10.0 feet and maybe even +/- 5.0' for some areas."

Identify Road Requirements for Wind Turbine Delivery

A network of access roads will be needed to deliver wind turbine materials and construction equipment to the proposed wind turbine locations. The access roads will be subjected to heavy loads for a relatively short duration. Project construction will involve the delivery of truck loads of concrete, reinforcing steel, wind turbine towers, wind turbine blades, and nacelles. These access roads will also be used for the long-term operation and maintenance of the facility.

Design Vehicle

Wind turbine blade transportation requires very long trailers that have unique roadway design requirements. A vehicle capable of transporting 123' long wind turbine blades was used to develop the concept layouts of the access roads. This blade length was used because it is a typical length for 1.5 MW wind turbine and is sufficient for concept layout purposes. The design vehicle used is shown in Appendix E and illustrates the vehicle dimensions used for this analysis.

Design Criteria

The roadway design criteria shown in Appendix E were developed in order to support the assumed design vehicle. Elements of this design criteria will be further described below.

Road Section

The access road typical section shown in Appendix F was developed to accommodate the assumed design vehicle. This design includes a 16' wide aggregate roadway with two 10' wide oversized shoulders on either side. The oversized shoulders are required to accommodate over-width construction and delivery vehicles and to allow them to navigate tight access roadway curves. These oversized shoulders would also accommodate the crane movements which are described later in this report. The access road structural section and subsurface soil correction treatments cannot be determined without site specific geotechnical investigations and subsequent recommendations. We have assumed a structural section based upon what has been used on past wind energy projects for estimation purposes.

Geotechnical

An access roadway section comprised of 10" of aggregate material over geotextile fabric (or geogrid) was assumed a reasonable section for purposes of this report. The 10' oversized shoulders are typically used to accommodate the over-width delivery and construction vehicles, but are abandoned after completion of construction. A site specific geotechnical investigation must be completed and recommendations must be provided to define the actual access roadway and oversize shoulder structural sections. In addition, identification of the delivery and construction vehicles with their performance criteria will be necessary for the geotechnical engineer to make recommendations.

Drainage

The overall existing drainage patterns for the facility site will need to be maintained. In addition, the drainage will need to be transported in such a manner to provide proper drainage and protection of the proposed access roadways. To provide positive drainage off the surface of the access road, a crown is shown with a 3% cross-slope on the typical section (see Appendix F). A 1% cross-slope is shown for the temporary 10' oversized shoulders. A 1% cross-slope is a typical minimum cross-slope to maintain positive drainage from a roadway surface.

Ditches are necessary to maintain positive drainage from the roadway and allow the roadway structural section to properly drain. The access road typical section shows 1:3 inslopes outside the oversized shoulders. A ditch with a minimum depth of 12" below the base of the assumed 10" aggregate material is recommended to provide free-board and allow the road structural section to drain. This 12" free-board should be provided to the extent possible.

A detailed drainage investigation with more accurate base map information and ground surveys would be required to identify drainage requirements. The dimensions shown were assumed for the access road typical section for purposes of estimation and need to be defined in later phases of analysis and design.

Drainage culverts will be necessary to maintain existing drainage patterns and minimize erosion damage to access roads. More detailed information and investigation will be needed to identify the specific project needs. For the purpose of this report, the quantity of drainage culverts were estimated based on a culvert every ¼ of a mile along access roads. A detailed hydrologic and hydraulic analysis of the site will be required to determine the drainage requirements and mitigation strategies in later phases of the project's development.

Identify Main Roadway Route

The following assumptions have been made in order to prepare the findings of this report:

- Wind turbine materials will be transported by the design vehicle (tractor-trailer configurations) from the port in Portland, Oregon to the proposed operation and maintenance (O&M) site. However, this does not rule out other routes which are all dependent upon a sourcing plan for where the material will come from; sea, rail, or highway transport, or combinations of all three.
- The existing roadway infrastructure will be used where possible in order to minimize roadway construction costs.
- The design vehicles will be able to navigate from the port to US-26.
- The existing infrastructure along this route will support and allow this transportation.
- Road construction or temporary restrictions along the proposed route will have viable detour routes available that meet the standard of the proposed route.

The following main roadway route from the Port of Portland was identified as a logical route for material delivery to the proposed O&M site:

1.	West on US-26.	86.8 mi.
2.	East on Simnasho Rd./S-400	6.5 mi.
3.	South on BIA-9/Simnasho Hot-Springs Rd./S-100	2.3 mi.
4.	East on BIA-3/Mutton Mountain Rd./S-300	10.8 mi.
	Estimated Total	106.4 mi.

The estimated total mileage given above considered a one-way trip to the O&M site from the Port of Portland. Some wind turbine materials may need to be directly delivered to the wind turbine sites instead of being taken to the O&M site. The fabrication, delivery, and construction schedules will likely influence these material delivery decisions.

Identify Staging Area and O&M Site

The proposed operation & maintenance (O&M) site provides an area for various services typically required for a wind energy project. Common components of an O&M site consist of a power substation, a building facility, and a lay-down area. The proposed O&M site was selected based upon accessibility and location within the project site. The final siting, performance criteria, design aspects, and costs associated with this site will need to be refined in subsequent phases of this project's development.

The selection of the proposed site was based on its central location, road access, and existing terrain. Based upon similar projects, a 15-acre site has been assumed adequate for this project. The proposed 15-acre site has been identified and is as shown on sheet GL04 in Appendix F. This site is divided into two areas, a 6-acre north and a 9-acre south portion. An access road would likely be required to provide access to the proposed O&M site. More accurate base map information, ground surveys, field review, geotechnical investigations, and recommendations are needed in order to properly consider the O&M site and access road designs.

A typical O&M site would also provide a location for a building and parking facility. The long-term site staff would normally use these facilities. All the systems and utilities typical of an operational and habitable building would be required. A typical building size for this type of use is on the order of 6,300 square feet.

The remaining portion of the O&M site could be used as a lay-down area. This lay-down area may be used to store construction materials and equipment. Depending on the fabrication, delivery, and construction schedule, an additional temporary lay-down area may be required. A location further from the project site could be determined if necessary.

Identify Civil Requirements for Wind Turbine Erection

The final wind turbine assembly and erection typically takes place in a prepared area surrounding the proposed wind turbine location. This analysis assumed that a 150’ radius would be cleared and leveled about the proposed wind turbine foundation centers. The wind turbine assembly area would be graded to a slope not to exceed 5%. Access roads to the wind turbine assembly area were exempted from the 5% slope requirement. This exemption may require further consideration during future design development. Earthwork quantities for the wind turbine assembly areas will depend upon each of the wind turbine base elevations and conditions. Earthwork quantities were therefore not directly calculated, but have been included as a component of the contingency costs. Additional consideration will be required in later design phases.

Crane Pads

A crane pad is typically located within the wind turbine assembly area and provides a location for the crane to conduct the wind turbine assembly. The minimum crane pad size was established as a 60’ by 40’ area with a 1% maximum slope assumed for safe and efficient crane operation. As previously described for the access roads, a site specific geotechnical report with pad structural section recommendations has not been performed for this project. This will need to be done in subsequent phases of this project’s development to identify the bearing capacity and compaction requirements for the crane pads.

Appendix F contains four sheets that show wind turbine typical layout crane pad options. The layout options selected for each wind turbine are shown in the wind turbine table of Appendix G. Once wind turbine construction is complete crane pads may be obliterated and returned to their preconstruction state.

Final Wind Turbine Entrances

A final wind turbine entrance is constructed to allow long-term maintenance access to each wind turbine site. The layout of the final wind turbine entrances is based upon the wind turbine typical layout crane pad options in Appendix F. A 4” aggregate base course with no geotechnical fabric was assumed for these final wind turbine entrances. Geotechnical investigations/recommendations, accurate base mapping, supplemental ground surveys, and identification of the actual vehicles to be used with their performance characteristics are all needed to more accurately identify the scope and extent of work needed for a site with these conditions.

Determine Crane Movement Road Requirements

Crane movement road requirements are described in the next two sections.

Crane Paths

A large crane will be required at each wind turbine in order to perform the wind turbine assembly. It is often advantageous to move a crane under its own power from site to site in order to avoid the costs associated with disassembly, transport, and reassembly of the crane at each site. Cranes may travel between wind turbines using the access roads which were described previously. In the absence of access roads, crane paths may be constructed to create a more direct crane route between wind turbines. The design/construction and maintenance of crane paths are highly dependent upon the type of crane used. This is an area of design that should involve a crane expert and geotechnical engineer to identify the alignment and loading requirements for the crane paths.

It is highly likely that cranes will need to move between wind turbine sites along access roads. The existing mountainous terrain suggests that the use of independent crane paths will be limited. A typical section for a crane path is located in Appendix F. Two crane paths, W2022 and E2936, are shown in the general layout sheets of Appendix F.

Crane Mobilization

In the event that a crane cannot travel between wind turbine sites under its own power, the crane will need to be disassembled, transported, and re-assembled. Crane mobilization, in addition to the initial mobilization, should be anticipated. It can be assumed that crane travel under its own power would not be desirable along existing major roads due to the potential for roadway damage and disruption to local traffic. Short instances of crane movements in order to cross existing major roads can be anticipated. As described earlier, crane paths were proposed where it appeared (from the base map information) that existing terrain would provide favorable conditions.

In general, logistics for construction of the wind energy facility is beyond the scope of this report. A possible scenario suggests that a crane could be transported to start at wind turbine number 0. Construction for wind turbine numbers 1 through 6 could then be completed by crane movement under its own power along the proposed access roads. In order to reach the next set of wind turbines the crane would likely require transport to wind turbine number 19. Construction for wind turbine numbers 7 through 24 and 60 through 66 could be completed by crane movement under its own power along the proposed access roads or crane paths. Another instance of crane transport will likely be required to relocate the crane to wind turbine number 26. Assembly for the remaining wind turbines numbers 25 through 59 could then be completed.

The ability for a crane to move under its own power is not only limited to horizontal and vertical alignment of paths (or access roads). This movement would also require adequate access road/crane path structural capacity to handle the crane vehicle loads. A geotechnical investigation along with a crane expert will be required to define the requirements. This must be done in subsequent phases of this project's development.

Prepare an Opinion of Probable Cost for Access Road Improvements

The opinion of probable cost was developed based on a conceptual layout, vertical and horizontal alignments, and quantities for aggregate material, earthwork, drainage, and geotextile material, as described in the subsequent sections.

Concept Layout

The proposed conceptual access road layout for the 99 MW array is shown in figure 11 below, and further detail is shown on the four general layout sheets located in Appendix F. Mutton Mountain Rd/S300 and Simnasho Hot-Springs Rd/S-100 will serve as part of the existing roadway route to the site due to their proximity to the project site.

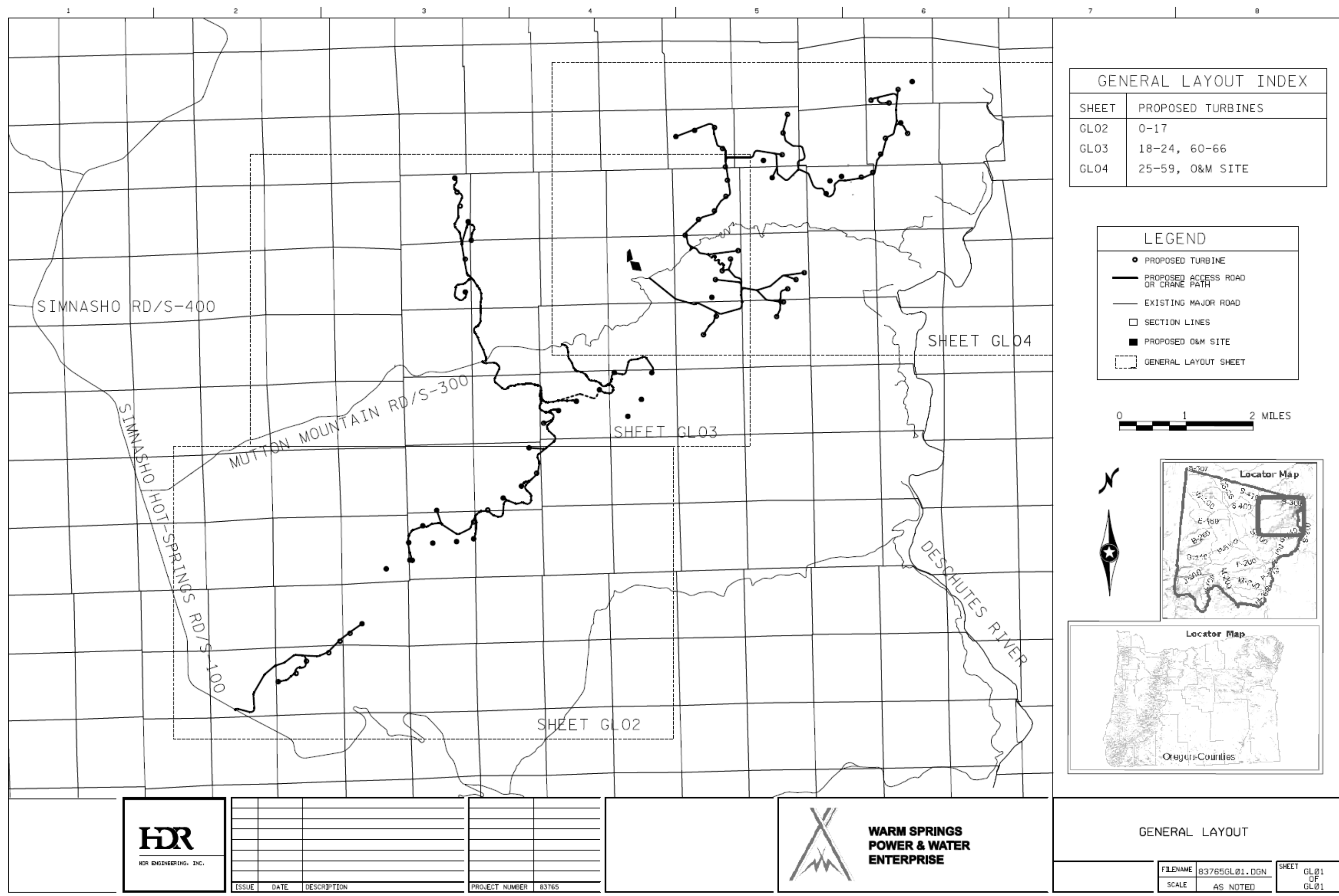

Figure 11. Conceptual access road layout for 99 MW array

Access Road Naming Convention

The naming convention for access roads were chosen to identify their general location within the project and the proposed wind turbines they will provide access to. For example, the access roads on the East side of the project begin with the letter “E.” Access roads on the West side of the project begin with the letter “W.” The next two numbers following the first letter generally indicate the lowest numbered wind turbine accessible along the road. The last two numbers generally indicate the highest numbered wind turbine accessible along the road.

The portion of Mutton Mountain Rd/S300 between proposed access road W2224 and E36 will require field review and design investigation. This portion of roadway appears to contain sharp horizontal curves that *may* exceed the design vehicle requirements. A field review of the existing roadway network will need to be undertaken to verify curve constraints in subsequent phases of this project’s development.

The turning radius details that were developed for the design vehicle were based on a 36’ wide access road. The access road turn detail is shown in Appendix F on the construction detail sheet (Detail B). A centerline turning radius of 200’ or more is typically required for wind turbine blade-haul vehicle to negotiate.

The existing road infrastructure will provide necessary access to the project site. The Developer and Road Authority (RA) will need to engage in precondition surveys of the existing roadway system that will be used to deliver materials to the project. It is likely some form of Highway Use Agreement between the Developer and RA will be required whereupon conditions for maintenance during use and post-construction mitigation requirements would be defined.

The condition of existing minor roads may be need to upgraded or altered in order to accommodate construction and delivery vehicle traffic to the proposed access road connection points. Assessment of the existing infrastructure will need to be undertaken in subsequent phases of this project’s development.

Access road concept alignments were established to avoid existing streams and wetlands to the extent the base map accuracy allowed. However, it can be anticipated that there will be impacts to streams that may require channel changes, or wetland impacts that may require mitigation. More detailed mapping and field reviews will be needed to determine the extent (if any) of the impacts in subsequent phases of project development.

The access road profile grade restrictions (10%) were found to be the most challenging element of the design criteria due to the proposed site’s mountainous terrain. Access roads were branched in many locations in order to reach proposed wind turbine locations that could not be reached otherwise.

Access roads to several proposed wind turbine locations were found inaccessible based on the terrain and infeasible earthwork that would be required to provide access. Proposed wind turbines 7, 8, 9, 10, 22, 23, 27, 45, 49, 50, and 59 were found to be inaccessible. Alternative wind turbine locations were developed through coordination with the meteorology subcontractor (V-Bar). These revised wind turbine locations were named with an “A” after the wind turbine number they replaced. The revised wind turbine locations are 7A, 8A, 9A, 10A, 22A, 23A, 27A, 45A, 49A, 50A, and 59A. The proposed access roads were designed to accommodate access to all the revised wind turbine locations.

Security and restriction of access to the proposed wind turbine locations is desirable, subject to approval by the Tribal Natural Resources department. Perimeter fencing and gates may be used to accomplish this. This report has considered installation of security gates for the seven access roads that connect with existing roads. Additional access restriction may be appropriate depending upon the conditions of the area and level of concern.

Access Road Profiles

With HDR's involvement with other wind power engineering projects, we have found standard industry practice indicates that road profile grades should not exceed 10%, however up to 14% grade can be tolerated with limited use and for roads with very flat horizontal curves at a maximum (no curvature desired). Details A, C, and D on the construction detail sheet of Appendix F were developed to guide the profile development for the roadways. The proposed road profiles can be reviewed from the 13 profile sheets located in Appendix F. The maximum profile grades for each access road are given in the roadway table of Appendix G. Our concept layout accommodated to the extent possible the maximum grade (both positive and negative grades). However, only the absolute values of the grades are shown in the tables.

Access road E55 has a 770' long portion of 13.63% grade that exceeds the 10% preferred maximum grade limit, but is within the 14% maximum tolerable grade limit. Construction and delivery vehicles use of this access road would be limited to only the wind turbine sites for 59A and 55. The majority of the maximum grade is along a straight alignment. The straight alignment provides favorable conditions for construction and delivery vehicles to negotiate the steep grade. Our investigation of the terrain as shown on the base map suggests there are no other feasible access routes to these wind turbine sites. If this steep grade was later determined unacceptable, the wind turbine base elevation could possibly be reduced in order to comply with a 10% access road grade limit.

Earthwork

Due to the mountainous terrain of the site coupled with requirements for construction and delivery vehicles, the construction of the proposed access roads will likely require very large volumes of earthwork. The estimated earthwork quantities developed in this report only consider the earthwork that would be required within the limits shown on the typical section sheet of Appendix F. Large amounts of earthwork will likely be needed outside these limits in order to support the typical sections and create stable side slopes.

The unknown slope stability conditions and geotechnical aspects of the site greatly influence the earthwork quantities needed outside these limits. The wide variability of these geotechnical conditions and accuracy of the base map information prevented the formulation of earthwork estimates outside the considered limits. An estimated contingency amount has been included to help capture some of this cost.

Future design efforts with more accurate base mapping, ground surveys, and geotechnical investigations with recommendations may allow for reduction of the estimated earthwork volumes. This would allow further refinements of the access road alignments (horizontal & vertical) to use the existing terrain more effectively. The incorporation of retaining walls may be a cost effective method to reduce earthwork in large embankment and excavation areas. Base mapping of sufficient accuracy for design, ground surveys, and geotechnical investigations with recommendations, and retaining wall studies are beyond the scope of this report.

Quantity Assumptions

The quantities examined for this report are limited to those shown in Appendix H. Due to the limited accuracy of the available information, several assumptions were necessary in order to obtain these quantities.

Aggregate Material Section Quantity Assumptions:

- Aggregate material section will only be required for the access roads and final wind turbine entrances.
- Section thicknesses and widths shown on the typical section sheet of Appendix F are representative of what we have experienced on other similar projects. However, identification of the actual vehicles and load configurations to be used along with site specific geotechnical investigation and recommendations will be necessary to identify the true access road structural section.
- Section thicknesses and widths shown on the four sheets of wind turbine typical layout crane pad options of Appendix F are representative of what HDR has experienced on other wind energy projects. However, involvement of a crane expert and identification of actual load configurations to be used along with site specific geotechnical investigation and recommendations will be necessary to determine the required structural section.
- A typical aggregate weighs approximately 2 tons/cubic yard. Aggregate base was estimated based on the width, length, and assumed depth of material on a compacted volume basis.

Earthwork Quantity Assumptions:

- Earthwork volume estimates done on this project are highly conceptual due to the vertical and positional accuracy of the available base map, the mountainous terrain, the variable conditions such as rock and soils that may not be suitable for construction. Also, geotechnical investigations and recommendations are necessary to better identify the *in situ* soils and mitigation strategies. We have used the base map information provided and have applied our best engineering judgment to develop order-of-magnitude quantities. These quantities were not without limitations, (described previously in this report) and so, the actual quantities will vary from our estimate.
- Earthwork quantities include: Excavation and Embankment, and have not been adjusted for shrinkage.
- Excavation was estimated to consist of 20% rock, 80% general excavation.
- The earthwork which is located outside the limits shown on the typical sections (see Appendix F) were not directly quantified due to the vertical accuracy of the

base map information, mountainous terrain, and unknown geotechnical conditions of the site. Some consideration for the earthwork located outside the limits shown in the typical section was included in the contingency cost.

Geotextile/Geogrid Quantity Assumptions:

- Must be confirmed by site specific geotechnical investigations and recommendations. We have assumed that a geotextile or geogrid material will be required below the access road aggregate base course and have included that in the estimate.

Gate Quantity Assumptions:

- Access roads that intersect Mutton Mountain Rd/S-300 or Simnasho Hot-Springs Rd/S-100 will be gated.
- Each gated access road will require a double 20' x 5' gate.

Drainage Assumptions:

A hydrologic and hydraulic investigation of the site with more accurate base map information will be required to determine the drainage requirements for this project. However, we have identified the following culvert assumptions for purposes of the estimate:

- One culvert every ¼ mile of roadway
- Inslopes of 1:3 from the edge of shoulder to top of culvert
- An average culvert length of 117'
- Fill height for culverts will not exceed 15'
- Half of the culvert quantity will be 18 inch diameter CMP
- Half of the culvert quantity will be 24 inch diameter CMP
- Two culvert end sections for each culvert

Task 4 Findings - Opinion of Probable Costs

Cost information is considered sensitive and confidential. The Opinion of Probable Costs, originally shown in Table 5 below, has been redacted from this document for public release. This estimate was developed based on quantities derived from the base information provided and qualified by the limitations of the provided information and assumptions described within the report and the appendix. This estimate only covers our opinion of construction related costs for the access roads and crane paths. This estimate does not cover project development costs required in subsequent phases of project development such as engineering, preparation of construction documents, survey, and geotechnical services.

Small adjustments to the estimated unit prices will cause large cost fluctuations due to the large quantities involved—this is especially true for earthwork. The estimated unit prices were developed with our best engineering judgment, understanding of industry practice, and publicly available data for bid item prices. Average bid item prices obtained from the Oregon Department of Transportation for 2007 were used as a basis for the estimate. The contingency value shown on the estimate was applied to cover project costs that require a level of detailed investigation that is beyond the scope of this report.

Table 4: Access road and turbine crane pad cost summary for 99 MW array

REDACTED

Task 4 Next Steps for Access Roadway Design Development

The base information presented, assumptions made, and engineering judgments used are believed appropriate for the conceptual level of detail contained in this report. Additional information should be obtained to advance beyond this concept stage. The findings from this additional information are necessary to advance the project to the next level of development.

Aerial survey:

An aerial survey of the proposed project site should be performed in order to obtain more accurate ground elevation data. Aerial survey required to advance a project to final design accuracy should have a vertical accuracy of +/- 1.0' with positional accuracy of at least 1' to 2'.

Site Supplemental Ground Survey:

Supplemental surveys along the proposed access road alignments should be performed to clarify areas of obstruction, or that need more refinement from what can be identified from the aerial survey information.

Design Vehicles:

In order to advance the design of access roads and assess the existing infrastructure it will be necessary to identify the specific design vehicles to be used to construct this site. Design vehicle criteria will be needed to identify the operating envelope to refine design and assess existing roadways. Examples of criteria would include weight, axle configuration, length, minimum turning radius, sensitivity to grade, et al. This would cover blade-haul, mast-haul, equipment-haul, crane, and other vehicles that are used for this project.

Field Reviews:

Field review of the existing roadway network and potential delivery routes should be performed to obtain additional information regarding the existing road conditions and identify potential issues.

Structure Investigation:

Structural capacities of the bridges along the proposed main roadway route should be investigated and evaluated with respect to the design vehicles to identify any constraints and subsequent mitigation strategies.

Hydrologic & Hydraulic Analysis:

Hydrologic & hydraulic analysis should be performed on the site to determine existing drainage patterns, flow for the proposed roadways in order to appropriately size, and locate proposed drainage features. These needs could have an influence on the cost and design of the proposed road alignments.

Construction Logistics:

A construction logistics plan needs to be developed to identify material and equipment sources, transportation routes, production schedule to identify specifics such as route plans, design vehicle requirements, and construction staging, et al.

Geotechnical Investigation:

A geotechnical investigation should be performed in order to determine the existing geotechnical conditions of the project site. Ground borings at strategic locations throughout the project site would likely be required. Based upon the findings of this investigation, roadway recommendations should be provided to ensure that appropriate conditions, load capacities, structural section requirements, and mitigation strategies are specified.

O&M Site Development:

Development of O&M sites requires the involvement of multiple disciplines to determine requirements for the O&M Site use. Designers involved with the power substation, building facility, lay-down area, construction logistics, roadways, etc. will need to work iteratively to determine a final design for the site. GE Energy has outlined the following specifications for the O&M site:

The Buyer shall provide the following on the Site for the Seller's personnel and equipment: a level area for one (1) personnel trailer 24 feet wide x 60 feet long; space for two (2) storage containers 40 feet long x 10 feet tall x 10 feet wide; a parking area for up to twenty (20) pickup trucks; space for two (2) portable restrooms; 220 and 110 volt AC power including making the connections to the Seller's trailer; and five (5) outgoing telephone lines including making the connection to the Seller's trailer.

Permitting:

Subsequent phases of this project's development must further consider environmental impacts and permitting requirements as outlined in Task 7: Biological Baseline Studies, Environmental Assessment, and Permitting

Final Civil Engineering for Roadways and Sites:

Final engineering for the access roadway improvements and individual wind turbine site improvements will be based on the conceptual design outlined in this study. Prior to the preparation of final construction plans, additional information will need to be provided by others as outlined above.

The horizontal and vertical alignments prepared for the conceptual design will then be revised to reflect this additional information. The alignments will be adjusted to meet the design requirements for vehicles expected to use the access roads, and minimize earthwork volumes necessary to construct the roads.

The access roads will be constructed in mountainous terrain, with numerous crossings of existing drainage patterns. The conceptual design assumed that culverts would be adequate to convey the design flows under the access roads. Further development of the design, analysis of the expected drainage flows, and more accurate topographic survey information may dictate the need for bridges in some locations. It is not possible to determine the number or sizes of potential bridges, if any, at this stage without more detailed study. For this reason, the design of bridges, if necessary, is not included in this preliminary opinion of probable cost.

For the conceptual design, proposed side slopes for the roadway grading were assumed to match a projection of existing ground where topography information was not available. Additional survey information may show a benefit in the use of retaining walls to reduce earthwork volumes. The extent of potential retaining walls, if necessary, cannot be determined without additional study and topographic survey information. For this reason, design of retaining walls, if necessary, is not included in this preliminary opinion of probable cost.

Final engineering for the wind facility is anticipated to include the following items:

- Preparation of design criteria for roadway, wind turbine site, the operations and maintenance facility site, and drainage improvements
- Revising base mapping to include additional survey information provided by others
- Field review of the conceptual horizontal alignments by design engineers
- Hydraulic analysis for proposed drainage crossings
- Incorporation of geotechnical investigation recommendations into the final design
- Final engineering plans for the access road improvements (approx. 36 miles)
- Final engineering plans for the wind turbine site improvements
- Final engineering plans for crane paths, if necessary
- Final engineering plans for improvements for an Operations and Maintenance site (excluding building design)
- Processing the final engineering plans through the necessary approving agency
- Preparation of Opinions of Probable Cost for the roadway and civil site improvements
- Preparation of construction specifications for the roadway and civil site improvements

Additional services may be necessary for the project, but are not included at this time due to uncertainty of their need, or lack of information at this time. These services may be provided as needed, but they are not included in the Opinion of Probable Cost for engineering services. These services include:

- Design of retaining walls
- Design of bridge structures
- Analysis of existing structures and/or roads to support delivery of wind turbine equipment and materials
- Design of utilities, other than storm culverts
- Design of site improvements for the production of materials to construct the access roads or wind turbine sites (quarries, concrete plants, etc.)

Construction plans for the proposed improvements will be prepared in accordance with requirements of the appropriate reviewing agency. Oregon Department of Transportation (ODOT) plan preparation standards will be used as a basis for this project if no other standards are required.

Chapter 5: Balance of Plant Opinion of Probable Cost

Task 5 Description

In Task 5 HDR prepared an opinion of probable cost for Engineering, Procurement, and Construction (EPC) for the proposed wind energy facility, based on the conceptual 99 MW design as established in Tasks 1 through 6. At this level of effort, HDR cannot provide detailed design drawings, but opinion of probable cost is provided for a single 99 MW wind energy facility layout.

Task 5 Activities

The sub-tasks for Task 5 are summarized below:

- Select wind turbine specification for study assumptions
- Determine best case initial phase install capacity
- Identify turbine placement sites and electrical substation site
- Estimate equipment procurement cost for delivery at project site
- Estimate construction cost for turbine erection
- Estimate requirements for turbine foundations and foundation design and construction

Select Wind Turbine Specification for Study Assumptions

This opinion of probable cost study is based on the assumption that that 66 General Electric (GE Energy) 1.5 MW xle model turbines will be installed at a hub-height of 80 meters to form a 99 MW array as the maxiumum capacity of the site, and that if the array size is reduced, that capital costs will be reduced roughly proportionally.

GE Energy has long been the predominant manufacturer of wind turbines in the United States; capturing 44% of market share in 2007 (see Table 2). The GE 1.5 MW xle model was selected by HDR for costing analysis due to its appropriate size, prevalence, reliability, and performance characteristics for the expected hub-height wind speeds below 8 meters per second (m/s) at Mutton Mountain. A description of the GE 1.5 MW xle model is included as Appendix I. GE Energy provided a budgetary quote for 66 1.5 MW xle turbines and for services related to the equipment and delivery, and this quote is included as Appendix A to this report. For energy production estimates, turbine delivery, foundation design, and tower and turbine erection, GE performance characteristics were assumed as representative for this study. In later stages of development, the turbine manufacturer may be confirmed through a competitive bid process, to ensure the most favorable equipment price, warranty, and contract terms for delivery and operations and maintenance. Possible alternative wind turbine vendors include Vestas (Denmark), Siemens (Germany), Gamesa (Spain), Mitsubishi (Japan), Suzlon (India), and Clipper (U.S. & U.K.).

Determine Best Case Initial Phase Install Capacity

This chapter describes the opinion of probable cost developed to characterize the maximum 99 MW capacity of the site. This study assumed the facility would take advantage of the maximum available capacity of the site in order to provide a full characterization of the region, so that if project downsizing must take place in later phases, low-performing regions could be eliminated, and the design could be optimized for maximum economic returns. A capacity of 99 MW was selected as the maximum of the topographic features at the site, and maximum likely to be borne by nearby transmission lines (BPA or proposed Tribally-owned line from proposed biomass plant). Turbines were sited in all locations likely to achieve a capacity factor over 17%. Turbine spacing and layout design guidelines are described in the section titled "Turbine Locations" below.

Results of initial economic analysis showed that overall per-MW revenues of the project may be significantly improved by removing low-performing turbines from the design, assuming capital costs would be reduced roughly proportionally. The final economic analysis for this report assumed that 13 outlying turbines would be eliminated, reducing the array size to 79.5 MW. Turbines numbered 1-7, and 45-50 were eliminated, as can be seen in Appendix J: Turbine Coordinates and Estimated Capacity Factors. The economic modeling results show improved estimated returns on investment for the modified 79.5 MW facility, consisting of 53 turbines. In later phases of project development, detailed design will be performed, to further characterize the reduced scope and cost of the 79.5 MW array. The economic analysis of this report assumes that balance of plant costs are reduced proportionally to the reduction in project size.

It was assumed that capacity would be available on the proposed interconnection lines to accept the maximum capacity of the site, based on the transmission study performed by Elcon Associates in the Phase 1 Wind Resource Assessment for this site. Actual available transmission capacity will be determined upon completion of a system impact study in conjunction with the transmission owner, once an interconnection request is filed. If available transmission capacity further limits the possible total capacity of the project, then the project design will be modified accordingly. Turbine coordinates and respective capacity factors are listed in Appendix J of this report, and wind speeds at each turbine location are shown graphically in Appendix D.

Opinion of Probable Cost for Turbine and Tower Equipment

Turbine and tower equipment costs are based on a budgetary quote provided by GE Energy, included as Appendix A. A summary of costs included in this quote is included in Table 6 below. Cost information is considered sensitive and confidential. This table has been redacted from this document for public release.

Table 5: Turbine and Tower Equipment Costs for 99 MW array

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This quote does not include anchor bolt templates, anchor bolts, rigging equipment, or lifting beam. Additional options available from GE Energy are included in the budgetary quote, in Appendix A. It should be noted that GE Energy will require additional site data before signing any agreement and it may be desirable to purchase additional warranty options or site staff training in addition to what is automatically included in the quote.

The cost of wind turbines and towers will vary depending on the state of the market at the time of procurement. In addition, the Tribes could issue a request for solicitation from the other major wind turbine manufacturers in order to minimize turbine cost. The turbine cost dominates the total installed cost and therefore, any significant reduction will have an impact on returns. The estimated capital cost should be adjusted in the economic model once equipment order negotiations have begun in order to more accurately estimate return on investment.

Turbine Placement Sites and Electrical Substation Site

The turbine array was designed by V-Bar meteorologists. The individual rows were selected based on the constraints of the terrain, coupled with the desire to maximize site capacity at 100 megawatts. Although some turbines are located in relatively low areas, the array was designed to keep the overall average annual net capacity factor at 30%.

The spacing requirements are based on the turbine model, which gives us a specific rotor diameter. The turbine under consideration, the GE-1.5 xle, has a rotor diameter of 82.5 meters. This turbine was chosen as suitable for the wind regime, long-term average wind speed less than 8.0 mps, and expected peak gusts less than 52.5 mps.

Turbine spacing within rows, and spacing between rows, is guided by manufacturer recommendations. This is usually no closer than about 2.5 rotor diameters, or roughly 206 meters for the GE 1.5 xle. This spacing is used when there is a narrow predominant wind direction and the terrain allows turbine rows to be laid out perpendicular to the prevailing direction. At the Mutton Mountain site, the prevailing wind direction is roughly northwest. The terrain is a major factor in laying out the turbines, as it is necessary to stay on the ridgelines to maximize the wind resource. Fortunately, many of the Mutton Mountain ridgelines are nearly perpendicular to the prevailing wind direction. In the locations where ridgelines are not perpendicular to the prevailing winds, the turbines were spaced further apart, to keep the overall wake losses under the industry standard of 2 percent.

Overall for this site, a spacing of 400 meters was used, plus or minus up to 100 meters. Adjustments were made to favor the terrain, in particular avoiding steep slopes. In the process of performing the road study, several turbines were relocated to accommodate the maximum allowable road grade for accessibility.

It should be noted that the turbine manufacturer will need to confirm this evaluation of the site for turbine suitability.

Figure 12, below shows fraction of annual energy production based on wind direction.

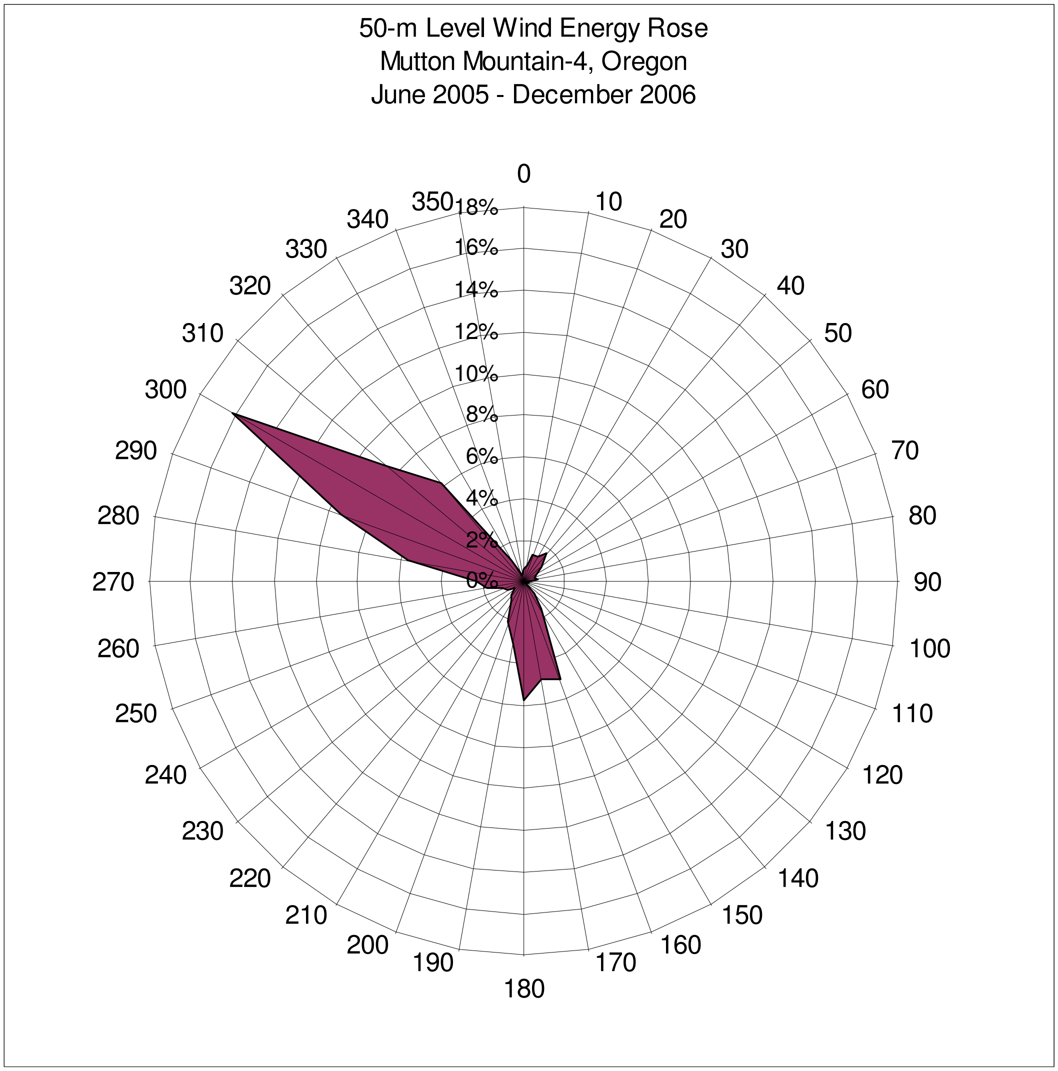

Figure 12. Fraction of annual energy production based on wind direction

V-Bar's array design was produced utilizing 5 years of on-site wind data, topographic maps, and meteorological experience. The project design was modified based on results of initial economic modeling. Layout may need to be further modified in future development phases to further maximize economic performance.

Geotechnical Site Assessment

Geotechnical exploration and tests must be performed for wind turbine foundation design, road design, operation and maintenance building design, and electrical system design. The scope outline below presents an opinion of probable costs for a geotechnical investigation for the project, prepared by James Rudd of American Engineering Testing (AET), and dated February 11, 2009. The full proposal can be found in Appendix S of this report.

Geotechnical Assumptions

AET's opinion of probable of costs for the geotechnical investigation are based on the following assumptions:

- A total of 66 wind turbines are planned.
- Site terrain is high plateau.
- Tree clearing will not be required.
- Length of transmission corridor options is 25 miles.
- Length of access roadways is 36 miles.
- Length of buried electrical cable alignment is 36 miles.
- Geology consists of bedrock at shallow depth (less than 10 feet of overburden).
- All turbine locations will be staked by surveyors prior to geotechnical investigation.

Scope of Geotechnical Investigation

AET's opinion of probable costs is based on the following scope of work:

- Mobilization of 3 drill rigs to the site.
- A dozer will be on-site to clear access to the boring locations.
- Drilling of a 30-foot deep rock core boring at each wind turbine location, plus four alternate wind turbine locations.
- Rental of a water tank, delivered to the site; plus rental of a water truck to transport water from the tank to the drill rigs.
- Drilling of 30 foot deep rock borings along the transmission corridors. A total of 25 borings along the corridor are assumed.
- Drilling of four (4) ten foot deep rock borings at the substation location.
- Drilling of thirty-six (36) borings along the access roadway alignments. Average depth of borings is 15 feet in soil overburden.
- Geophysical testing, consisting of thirteen (13) MASW tests at turbine locations and thirteen (13) field resistivity tests (Wennar Array).

- Thermal resistivity testing of twenty (20) samples along underground cable alignment.
- Geologic reconnaissance of the project site to identify potential geologic hazards.

Opinion of Probable Cost for Geotechnical Investigations

Based on the above assumptions, AET provided an opinion of probable cost of geotechnical investigation for the 99 MW array. An itemization of the estimated costs is shown in Table 7 below. Cost information is considered sensitive and confidential and has been redacted from this document for public release.

Table 6: Cost summary for geotechnical investigations for 99 MW array

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Wind Turbine Foundation Design

HDR has prepared a planning-level opinion of probable cost for wind turbine foundation design based on typical design assumptions. A detailed engineering design will need to be prepared for turbine foundations including, but not limited to the following:

- Engineering drawings,
- Technical specifications, and
- Design calculations.

The foundation design will be based on the geotechnical design parameters, wind turbine manufacturer design requirements, and the standards of the industry. It is assumed that one foundation design will be adequate for all proposed locations at the project. If geotechnical investigations reveal that soil bearing pressure varies significantly from site to site (for example from 2500 psf to 4000 psf), then more than one foundation design may be used. HDR does not exect this to be the case for the Mutton Mountain site, pending results of geotechnical investigations. The following structural engineering analysis is assumed to be included in preparation of the design:

- Footing size and dimensions.
- Foundation design and engineering based on the turbine manufacturer's loads.
- Global stability for overturning and sliding.
- Foundation stiffness.
- Calculation of foundation internal moments and shears.
- Concrete design to American Concrete Institute (ACI) 318.
- Connection design including anchor bolt layout and sizing, embedment plate sizing, tower flange bearing and grout.
- Backfill density and grading above and around the foundation.
- Response to requests for information or clarifications of its design from an independent engineer.
- Development of one standard detail for sloping or benching of the ground at the foundation excavation based upon the results of the geotechnical investigation.
- The foundation design is typically sealed by a registered professional engineer licensed in the State of Oregon.

The deliverable design package typically consists of the following:

- Certified foundation design drawings, certified foundation documentation upon completion, and technical specifications.
- Preliminary draft set of foundation documents

- Sealed foundation design drawings (final design), technical specifications, and foundation design reports
- Design computation reports for third party reviews.
- Drawings, calculations, and other required data in compliance with local, county, state, and other applicable codes or industry standards.
- Participation in meetings to address the basis of design of calculations, clarifications, or third-party review comments relevant to the submitted engineering packages.

Table 7: Wind Turbine Foundation Engineering Design Cost Summary

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The above-outlined scope and cost is based on one foundation design, which will be reproduced for all wind turbines in the facility, so regardless of the number of turbines, the design cost remains the same.

Wind Turbine Foundation Construction

As no geotechnical report has yet been performed for use in developing the design of the turbine foundations, the geological data received from the Confederated Tribes of Warm Springs GIS Center (see Appendix K) was used as representative information of the sub-grade conditions at the wind turbine locations. From the geological data profiles, the turbines locations appear to be situated primarily on Mafic Pyroclastics, i.e., bedrock.

The wind turbine generator is taken to be a GE 1.5MW xle, and the presumption for the project is that an octagonal shaped inverted-T spread footing type foundation (see Appendix L) for support of the tower and turbine will prove to be the most economical, not only in the design effort, but also from a materials/construction standpoint.

The following assumptions have been made in order to prepare the findings of this report:

- The soil bearing capacity is between 4ksf and 5ksf.
- The underground water level is at least 9ft below the grade.
- Seismic conditions are not a factor in the loading development and subsequent design.
- In developing a preliminary design, the following forces are accounted for as acting on the foundation:
    - The moment and horizontal shear force induced by wind loads.
    - The vertical force due to the self-weight of the wind turbine and tower.
    - The self-weight of the reinforced concrete foundation.
    - The weight of the soil above the foundation.

- The lateral force exerted by the soil.

Three limit states, Ultimate Limit State (ULS), Serviceability Limit State (SLS) and Fatigue Limit State (FLS), are analyzed and checked in the foundation design.

Typically, the loads provided by the turbine manufacturer are characteristic loads (L_c). The design loads (L_d) are determined by the application of a load factor γ_f :

$$L_d = \gamma_f L_c$$

To develop a basis for calculating foundation costs (per wind turbine site) of concrete, steel, grout, excavation backfill, equipment use, etc., the foregoing parameters were used in preparing a preliminary foundation design and layout (see Appendix L). The breakdown of the representative costs are shown in tabular form in Appendix M.

If the actual soils sub-grade conditions, based on a final geotechnical report, are different than what has been assumed, i.e., the allowable soil bearing pressure is less than 4ksf, then the wind turbine foundation will need to be adjusted accordingly potentially resulting in greater material cost.

Table 8: Wind Turbine Foundation Cost Summary for 99 MW array

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Opinion of Probable Cost for Equipment Delivery at Project Site

The costs of delivery of turbines, towers, and associated equipment are shown in Table 10 below (source: GE Energy budgetary quote, included as Appendix A).

Table 9: Cost of Delivery of Turbines, Towers, and Associated Equipment for 99 MW Array

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Construction Cost for Turbine Erection

Construction costs for tower and turbine erection were estimated by HDR Design-Build. The summary of estimated turbine and tower erection costs is provided in Table 11 below. Costs include labor, permanent materials, construction materials, equipment, and subcontractors. The detailed opinion of probable cost report is included as Appendix N.

Table 10: Construction Costs for Tower and Turbine Erection for 99 MW Array

REDACTED

FAA Lighting

The cost of obstruction lighting for aviation purposes, mounting kit, and synchronization, is shown in Table 12 below, based on the budgetary price quoted by GE Energy, included as Appendix A .

Table 11: Cost of Obstruction Lighting for Aviation for 99 MW Array

REDACTED

Task 5 Conclusions

Balance-of plant costs for the 99 MW Array are summarized in Table 13 below. Costs for the 79.5 MW array are summarized in Table 14.

Table 12: Opinion of Probable Cost Summary for 99 MW Array

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Table 13. Opinion of Probable Cost Summary for 79.5 MW Array

REDACTED

Chapter 6: Electrical System Cost Estimate

Task 6 Description

Elcon Associates, Inc. (Elcon) was retained by Warm Springs Power and Water Enterprises (WSPWE) to complete a conceptual study and cost estimate of the proposed 99 MW Mutton Mountain Wind Farm collector system, project substation, transmission tie line and interconnection switching station. The proposed locations for 66 wind turbines were provided by HDR.

This chapter describes the opinion of probable cost developed to characterize the maximum 99 MW capacity of the site. This study assumed the facility would take advantage of the maximum available capacity of the site in order to provide a full characterization of the region, so that if project downsizing must take place in later phases, low-performing regions could be eliminated, and the design could be optimized for maximum economic returns.

Results of HDR's initial economic analysis show that overall per-MW revenues of the project may be significantly improved by removing low-performing turbines from the design, assuming capital costs would be reduced roughly proportionally. HDR's final economic analysis for this report assumed that 13 outlying turbines would be eliminated, reducing the array size to 79.5 MW. Turbines numbered 1-7, and 45-50 were eliminated, as can be seen in Appendix J: Turbine Coordinates and Estimated Capacity Factors. The economic modeling results show improved estimated returns on investment for the modified 79.5 MW facility, consisting of 53 turbines. In later phases of project development, detailed electrical design will be performed, for the reduced scope and cost of the 79.5 MW array.

Task 6 Conclusions and Recommendations

There are two obvious possibilities to interconnect the Wind Farm into the regional grid. Both interconnections are at 230 kV. One is to connect into the BPA 230 kV Jones Canyon to Santiam circuit which is routed several miles west of the project. The other interconnection possibility is to route the transmission line south to the town of Warm Springs and interconnect with a proposed 230 kV circuit which is being considered to deliver power to PGE's Round Butte Substation from a proposed 18 MW Biomass project.

A 10 mile transmission line will be required to connect to BPA. To connect to the BPA system, WSPWE will be required to finance a 3-breaker ring bus switching station. (Most of the investment will be recovered through transmission credits.) The advantage of connecting into the BPA circuit is that power can be delivered to several off-takers in the Northwest and only BPA transmission charges will be required. The concern with this interconnection option is that the BPA circuit is already heavily subscribed and there are other applications to BPA to interconnect to the line. Elcon suspects that before WSPWE can interconnect to the Jones Canyon to Santiam line, other lines will have to be constructed in the area to reduce the load on the Jones Canyon to Santiam circuit.

A 20 mile circuit will be required to connect to the Biomass circuit. WSPWE can connect to the Biomass circuit and deliver power to PGE, thereby avoiding the BPA transmission charges (assuming that the power is sold to PGE).

The balance-of-plant electrical system is illustrated in Figure 13, below. The substation is to be located near the center of the project adjacent to Mutton Mountain Rd/S 300. The substation will have a 230 kV breaker, 110 MVA transformer, 35 kV breakers for 4 collector circuits and a capacitor bank. Costs are summarized in Table 15, below. Cost information is considered sensitive and confidential and has been redacted from this document for public release.

The estimates include different costs to interconnect to the PGE system and to connect into BPA. In addition, the BPA interconnection will require a switching station which WSPWE will be required to finance. The charges to WSPWE for this switching station will be refunded by BPA over a period of about 5 years by crediting transmission charges for power wheeled over the BPA system.

Elcon recommends that WSPWE submit interconnection applications to BPA and PGE to determine interconnection requirements including cost estimates for interconnection.

The interconnection costs presented above are representative cost estimates made without the benefit of input with BPA and PGE for the Mutton Mountain Wind Farm.

Task 6 Transmission Line

To connect the project substation to the interconnection point, Elcon recommends a 795 kcm ACSR circuit. The line is to be routed along Mutton Mountain Road/S 300 from the project substation to the interconnection of S-300 with Simnasho Hot – Springs Rd/S-100. At this point, the line is to be routed cross country in a north westerly direction if the interconnection is with BPA. If the interconnection is to be with the Biomass 230 kV circuit, then the line is to be routed cross country to Warm Springs. Transmission line routing is illustrated in Figure 1.

The transmission line cost was estimated. This estimate includes an allowance for one fiber optic circuit.

Task 6 Project Substation

A reasonable substation site was found on the north side of Mutton Mountain Rd/S-300 on the east-central part of Section 17. Please refer to Figure 1 for the proposed substation site location. The site is rocky and will require that careful attention be made to grounding issues, but those can normally be resolved.

A one line diagram of the proposed substation is presented in Appendix O, Figure 2. The substation cost estimate is presented in Appendix O, Table 2. Major cost elements are:

1. 230 kV Power Circuit Breaker
2. Power transformer
3. 34.5 kV Power Circuit Breaker (5 each – 4 for collector circuits and 1 for capacitors)

The actual requirements for voltage control and power factor correction at the project substation will depend on the type of wind turbine as well as the requirements of the affected utility – either BPA or PGE. Elcon has included costs for a 20 MVAR switched capacitor bank. There may or may not be a requirement for Dynamic Voltage Control. Interconnection studies by BPA or PGE will determine the actual requirements. If GE wind turbines are installed, the requirement for a separate Dynamic Voltage Control may be avoided, assuming that the wind turbines themselves include the Dynamic voltage Control option. If required, a 4 MVAR Dynamic Voltage Control unit could be added to the project substation. An 8 MVAR installation would increase the cost.

Task 6 Collection System

To develop the collector system, Elcon personnel visited one half of the proposed turbine sites to obtain a general understanding of the constructability of the required electrical system that would transmit generated power from the proposed 66 turbines to the project substation.

The Mutton Mountain area was found to be hilly and very rocky. These conditions will make installing underground cables costly. It will be necessary to build underground circuits along turbine strings to avoid turbine interferences. Cost estimates were developed for installing both overhead and underground circuits from the turbine strings to the project substation.

The proposed collector system layout is presented in Figure 13 below.

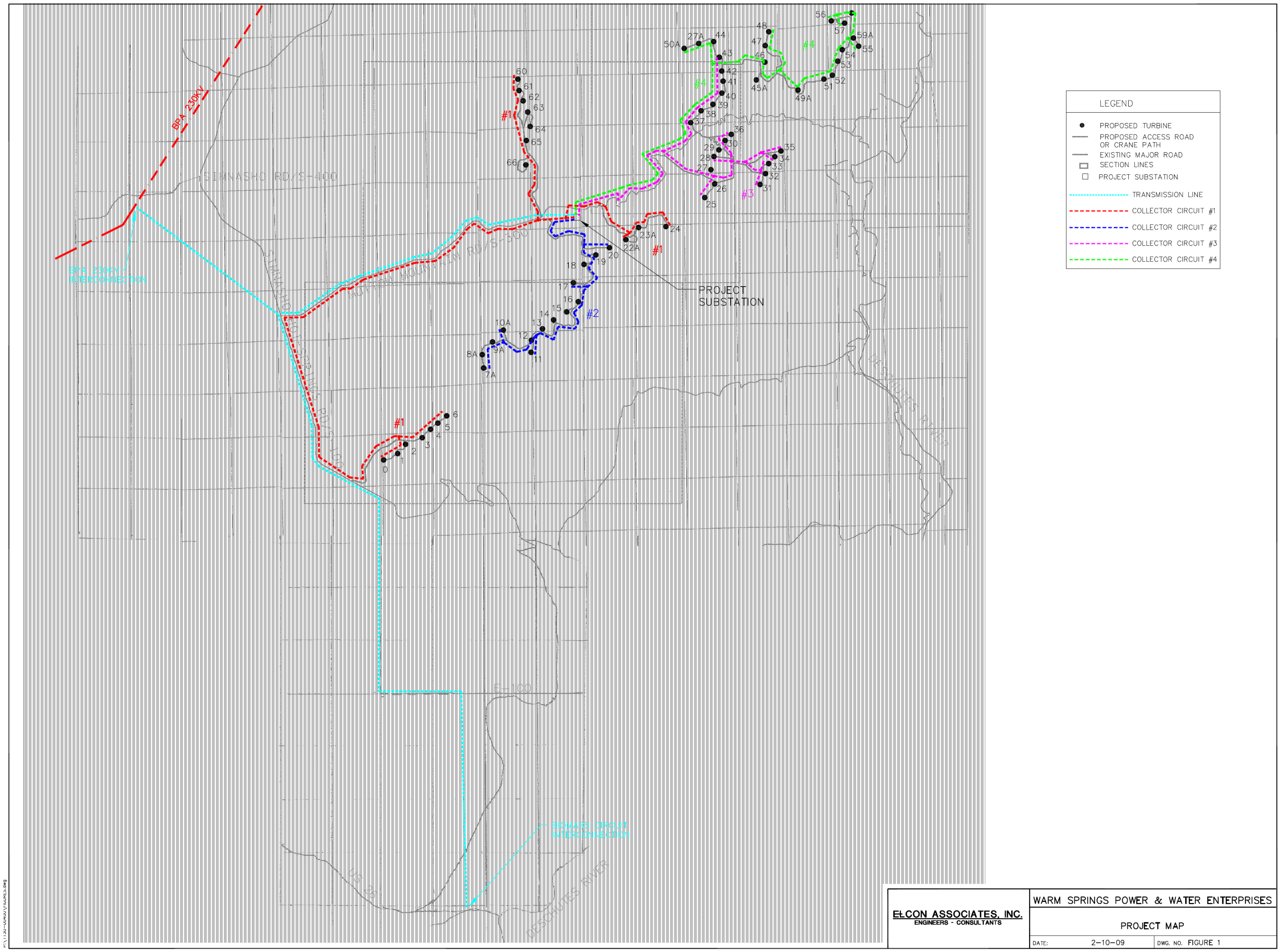

Figure 13. Electrical System Layout for 99 MW Array

Schematics for each of the collector circuits which show the collector circuit conductor sizes, length, and loading are presented in Appendix O, figures 3 - 6. The figures also show conductor sizes for the overhead options which may be employed from the turbine strings to the project substation. Cost estimates for the all underground options and the partial overhead option are presented in Table 3 in Appendix O. Tables 4 and 5, also in Appendix O, show the development of unit cost data for the underground and overhead circuits. Underground cost estimates have been developed for both plowing and trenching and backfill. The trenching and backfill unit costs are somewhat higher and these costs have been used for estimating the installed cost of the underground circuits.

Costs for each of the required 66 turbine step-up transformers (1,500 KVA) were estimated. Their costs are included in the collector system cost estimates.

Estimates for the optional overhead segments of the collector circuits are based on separate pole lines for each of the circuits. There is a potential to construct at least part of the overhead section of Collector Circuit 1 as an underbuild to the transmission line. Portions of the overhead parts of circuits 3 and 4 could be constructed as a double circuit.

Table 14: Electrical System Cost Summary

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Chapter 7: Biological Baseline Studies, Environmental Assessment, and Permitting

Task 7 Description

HDR has outlined the regulatory framework for the project and estimated the cost and time required to prepare and obtain approval of all necessary preconstruction environmental assessments and permits for the proposed 99 MW array. This effort was supported by the tribal Natural Resources Department and Tribal legal counsel. For purposes of economic analysis, it was assumed that environmental and permitting costs would remain constant, independent of array size.

Task 7 Activities

HDR developed a table outlining the likely required permits and approvals, and a scope of work summarizing biological baseline studies, environmental assessment, and permitting costs. The table is included as Table 16. Cost information is considered sensitive and confidential, and has been redacted from this document for public release. The scope is included in the following sections of this report.

Task 7 Deliverables/Findings

The Environmental assessment and permitting scope of work outlined below is based on the requirements of the Warm Springs Tribes *Integrated Resource Management Plan* (IRMP), the guiding document for compliance for approvals and permits under the Tribes' jurisdiction. The scope incorporates wildlife, avian, raptor, and bat study recommendations made by Northwest Wildlife Consultants, Inc., which prepared the *Warm Springs Wind Power Project Mutton Mountain Vicinity Initial Wildlife Reconnaissance* (April 29, 2006). The recently completed *Oregon Columbia Plateau Ecoregion Wind Energy Siting and Permitting Guidelines* (September 29, 2008) also provided guidance for gathering information relating to plants and animals to determine potential effects of the proposed wind energy facility.

This project will require completion of a Project Assessment (PA) by the Tribes. The requirements for completion of the PA will be determined once the Tribes' Branch of Natural Resources initiates the project and forms a Project Interdisciplinary Team. This team, which may include consultants, will prepare the required documentation for review by the Resource Manager Interdisciplinary Team. Once this team approves the project, a recommendation will be made to the Tribal Council. The Tribal Council must approve the project prior to project initiation.

In addition to preparation of the PA, this scope of work includes preparation of applications for permits and approvals that will likely be required for project initiation. A summary of permitting requirements is provided in Appendix P.

The opinion of probable cost included in this scope of work provides an estimate as if the work were to be completed by a consultant. This scope and opinion of probable cost will likely be refined by the Project Interdisciplinary Team upon project initiation. Expenses related to travel and equipment (such as Global Positioning Systems, etc.) are not included in this estimate because roles and responsibilities have yet to be defined.

This scope of work is based on the following assumptions:

1. The wind facility would generate a maximum of 99 megawatts (MW) and would consist of 66 turbines with a capacity of 1.5 MW each.
2. Based on HDR's experience with similar projects, it is assumed that the project will result in disturbance of approximately 300 acres during construction. Approximately 150 acres would be permanently disturbed and approximately 150 acres would be restored after construction. These footprint acreages should be confirmed in later stages of design development.
3. The Project consists of an operations and maintenance facility, staging areas, turbine pads, roadways, and construction of underground electrical cables, transmission feeder lines and a substation. Construction activities will include filling and grading relating to site and road construction, trenching, installation of culverts, cement production, and erection of the turbines, operations and maintenance facility, and the substation.
4. Based on HDR's experience with similar projects it is assumed that field surveys will focus on areas within 300 feet of proposed turbine locations and within 250 feet of the centerline of linear features (access road and electric collector system).
5. It is assumed that the project will result in a finding of no effect or not likely to adversely affect federally listed species or their habitat. Formal fish surveys are therefore not included in this scope of work. If formal surveys become necessary, it will be the subject of an amendment to this scope of work, possibly resulting in additional cost.
6. A stormwater prevention and pollutant plan consistent with National Pollutant Discharge Elimination System (NPDES) requirements will be prepared as part of the engineering scope of work.
7. An erosion control and prevention plan will be prepared as part of the engineering scope of work.
8. Construction air emissions may require a permit from EPA. A permit application will be prepared using EPA standards as part of the engineering scope of work.
9. Information generated from Tasks 1 and 2 will be sufficient to complete required permit and approval applications for the Project.
10. It is assumed that the Project will meet the requirements of the U.S. Army Corps of Engineers (Corps) and EPA nationwide permits (NWPs) to satisfy Sections 401 and 404 of the Clean Water Act.
11. There are two options for transmission interconnection: Scenario A: transmission line will interconnect on tribal land to BPA lines located in the leased right-of-way approximately 10 miles west of the facility and Scenario B: transmission

lines will extend approximately 20 miles and interconnect on tribal land to the proposed tribally-owned biomass facility and then to PGE's Round Butte Switching Station.

12. It is suggested that the Project Team consider post construction habitat restoration and wildlife casualty monitoring to continue to gather information regarding the effectiveness of methods used to avoid, minimize, and/or mitigate project impacts. In addition, an adaptive management plan should be prepared and evaluated regularly. This should be included as part of an agreement to address impacts, and will likely be a condition of project approval.

Subtask 1 – GIS Analysis and Mapping

The Project Team will develop a project Geographic Information System (GIS) in ArcGIS. This will include layers of information that will be used to analyze resource information and develop maps necessary for analysis in the Project Assessment. As needed, the Project Team will compile available information and data gathered during field investigation for the project and prepare the following maps:

- Cultural Resources
- Water Resources and Wetlands
- Range and Agricultural Resources (Vegetation)
- Soil Resources
- Fish and Wildlife (up to three additional maps for raptor, bat, and avian survey information)
- Terrestrial Habitat Map
- Aquatic Habitat Map

Deliverable: GIS maps.

Subtask 2 – Prepare Project Assessment Biological and Cultural Resource Studies

Subtask 2.1 Cultural Resources

The Project will take place solely on reservation land; therefore, compliance with Section 106 of the National Historic Preservation Act (NHPA) is not required. However, the Tribes must satisfy its own requirements for identification and protection of these resources. Historical sites, cultural plants, traditional use areas, and archeological sites located in the project area will be identified. Avoidance of cultural resources identified will be a priority for the Project.

Identification of resources will include review of project plans to determine the potential impact on cultural resources of areas slated for disturbance (roadways, turbine placement sites, staging areas, transmission line corridor, etc.). In addition, a review of Tribal records and interviews with Tribal staff will be completed. Based on this information, the Project Team's archeological consultant will complete a field investigation (i.e., visual investigation of the ground surface conducted by walking sections of the area). If more extensive investigation is required (e.g., shovel probing) an additional scope of work will be prepared. Based on field findings, potential impacts will be identified and mitigation measures, if required, will be proposed.

Deliverable: Cultural Resources Report

Subtask 2.2 Wetlands and Water Resources

There are several streams and waterholes located in the project area and road construction that will require the placement of culverts. The Project Team's wetlands biologist will conduct an on-site inspection of streams and wetland delineation of the construction areas within the project area (approximately 500-foot-wide corridors) using the methods described in the 1987 *Corps of Engineers Wetlands Delineation Manual*, *Technical Report Y-87-1*. Wetland boundaries will be surveyed using a Trimble Pathfinder ProXRS (or equivalent) Global Positioning System (GPS). This will provide a permanent record of the wetland boundaries on the site. A wetland delineation report will be prepared that will document the findings of the field survey and identify necessary wetland and waters permits for project construction.

The Project Team will also delineate streams, floodplains, and drainage patterns. The potential impacts analysis will focus on the potential pollutants generated for the proposed project. Analysis for both short-term (construction) and long-term will be completed.

Deliverable: Wetlands and Water Resources Report

Subtask 2.3 Range and Agricultural Resources (Vegetation)

Project Team biologists will field investigate plant cover types. Particular attention will be paid to identifying sensitive areas such as cultural plants identified in Task 2.1, riparian zones, and habitat for federally listed (sensitive, threatened, or endangered) or endemic plant species. Based on field findings, potential impacts will be identified and mitigation measures, if required, will be proposed.

Deliverable: Range and Agricultural Resources (Vegetation) Report

Subtask 2.4 Soil Resources

The Project Team geologist will prepare a soil conditions and geology report. The report will be based on field geotechnical data gathering and geotechnical recommendations prepared by the engineering team for site development. The report will provide recommendations for soil conservation, erosion control, and restoration where possible to support native vegetation. No field additional investigation outside of that completed by the engineering team will occur as part of this task.

Deliverable: Soil Resources Report

Subtask 2.5 Terrestrial Wildlife, Avian, Raptor, and Bat Studies

The Project Team wildlife biologists will conduct a literature review, consult with local experts, and conduct field reconnaissance to evaluate the presence of habitat types, including grasslands, forest, riparian woodlands, cliffs, and streams. The presence of state or federally listed Endangered, Threatened or Sensitive Species, designated Critical Habitat, and other wildlife habitat will be evaluated. The Project Team will identify terrestrial wildlife use in the project area. In addition, given the location of the project, the following pre-construction studies are recommended:

Avian Use Surveys

The primary objective of the Use Study is to evaluate the impacts of the project on summer and migrating birds. Surveys will be conducted every other week from March 1 through November 15. Twelve fixed points (circular plots) will be systematically established within the area proposed for development so that data collected on avian use is well representative of the entire project area. The surveys will focus on raptors and other large birds, and birds seen within and beyond 800 meters of the fixed points. During each survey, results will be recorded and mapped. In addition, all birds (including small passerines) will be recorded within 100 meters of the points.

The distance to each bird observed will be estimated to the nearest meter. The survey radius of the circular plots will be up to 2,625 feet (800 m) depending on terrain limitations. Observations of birds beyond the specified radius will be recorded, but data collected on these birds will be analyzed separately from data collected on birds observed within the plot. Plots will be surveyed for 20 minutes each and the following will be recorded: the date, start, and end time of the observation period, plot number, species or best possible identification, number of individuals, sex and age class, distance from plot center when first observed, closest distance, height above ground, activity, habitat, and flight paths.

Raptor Nest Survey

One full season of raptor nest surveys will be conducted. The survey will determine the species and nest location(s) that will potentially be disturbed by construction activities. The survey will identify active, potentially active, and alternate or historic (active within the past five years) nest sites with the highest likelihood of impacts from the operation of the project. A larger survey area outside the boundaries of the project corridors may be necessary if there is a likelihood of nesting or other use by state or federally protected or sensitive raptor species (e.g., ferruginous hawk, Swainson’s hawk, bald eagle, golden eagle).

The field biologist will drive all public roads and other accessible areas one time in the spring of 2009 for a dedicated raptor nest survey. This one pass survey will be augmented with other survey efforts occurring throughout the year, but one dedicated survey will allow the biologist to focus on searching for raptor nests. Each nest observed will be mapped and species recorded if the nest is occupied. If the nest is unoccupied, potential species or type of raptor will be recorded.

Bat Surveys

Although little is known about bats in the project area, there is information available on bat species composition in an area approximately 25 miles south of the project area. The Pelton Round Butte Hydroelectric Project is located in central Oregon at the transition between the East Slope Cascades and High Lava Plains physiographic provinces. This landscape is very similar to the Mutton Mountain wind project area[3].

The Project Team proposes to collect data at the project site using Anabat units (four are proposed). Using this method, bat calls (if they are present) will be recorded. The proposed monitoring period is June through October 2009. The Anabat units will be rotated through the sample points. Each sample point will be recorded over a four week period and the Anabat units will be serviced (new flash card and batteries every other week) and location shifted at the end of the four week period.

Deliverable: Terrestrial Wildlife, Avian, Raptor, and Bat Report

Subtask 3 – Prepare Permits and Approvals

More detailed information is presented in Attachment A: Permits and Approvals Required for Project Development. It is assumed that the Bureau of Natural Resources (BNR) will prepare the required permit applications, including those required by agencies outside the Tribes and will coordinate to provide any additional information for required approvals.

The opinion of probable cost for this task should be reviewed and revised by BNR prior to project initiation. It is also suggested that BNR confirm the assumptions on which this scope of work is based and meet with agency staff early in the project to verify the requirements of approvals required outside the Tribes. The following is a list of anticipated permits and approvals required for the project:

1. **IRMP Compliance:** The project will require preparation of a Project Assessment in accordance with the Tribes' Integrated Resource Management Plan.

2. **Building Permit:** A building permit will be required for construction and installation of project facilities, including power and plumbing.

3. **Section 401 Nationwide Permit Approval:** Section 401 is invoked for in-water work (culverts) and/or when Corps Section 404 permitting is required.

4. **General NPDES for Construction Stormwater:** A Notice of Intent (NOI) must be prepared and submitted to the EPA with the required supporting documentation.

5. **404 Fill/Removal Nationwide Permit:** An approval by the USACE is required if filling streams and/or wetlands under the jurisdiction of the USACE.

6. **FAA Permit:** The FAA regulates structures exceeding 200 feet on reservation and nonreservation lands.

7. **EPA Air Quality Permit:** Rock crushing will require EPA approval if emissions exceed thresholds.

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[3] Northwest Wildlife Consultants, Inc. *Warm Springs Wind Power Project Mutton Mountain Vicinity Initial Wildlife Reconnaissance* (April 29, 2006).

8. **Oversize and Overweight Permit:** A permit will be required from Oregon DOT for transporting oversize or overweight loads in or through Oregon.

Summary of Costs

The opinion of probable cost for environmental services on the Mutton Mountain Wind Energy Development Project are summarized below.

Table 15: Costs of Environmental Studies and Permitting

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Chapter 8: Financial Modeling

Task 9 Introduction

HDR developed an economic model to estimate the 20-year cash flow and return on investment for the proposed project, based on assumed financial parameters, from industry experience, discussions with experts, and prior studies. In the preparation of this report, and the opinions and recommendations that follow, HDR has made forward-looking statements including information concerning possible or assumed future results of operations of the proposed project. HDR has used and relied upon certain information and assumptions provided by sources that HDR believe to be reliable. Although HDR believes that these forward-looking statements are based on reasonable assumptions, forward-looking statements are subject to numerous factors, risks, and uncertainties that could cause actual outcomes and results to be materially different than projected. WSPWE should not place undue reliance on forward-looking statements. HDR cannot give any assurance that any of the events anticipated by any forward-looking statement will occur, or if they do, what impact they will have on WSPWE. Therefore, the actual results can be expected to vary from those estimated to the extent that actual future conditions vary from those assumed by us or provided to us by others.

The following factors are among those that could affect the future economic performance of the proposed project, and could cause the results to differ materially from those expressed in the forward-looking statements included in this document or any document referenced herein: equipment and construction costs, annual average energy production (capacity factor), electricity sale price, interconnection cost, annual variable costs (operation and maintenance, shaping and integration, wheeling charges, and other miscellaneous costs that are a function of the amount of electricity produced on the site), annual fixed costs (service warranty and parts, equipment insurance, management and administration, utilities, and property taxes), annual cost inflation, equity investor's role and income tax rate, asset depreciation schedule, availability of grant funding, and debt financing rate and term. The information contained herein is sensitive business information, and this document is considered confidential, not for public release.

Task 9 Description

Upon completion of preliminary design and opinion of probable cost for the full 99 MW array, HDR was able to use the opinion of probable cost information as the basis for the economic model, to calculate the 20-year cash flow for the project, and to estimate return on investment. Based on this full characterization of the 99MW array, opportunities were identified to improve the economic performance of the project, by eliminating low-performing turbines and reducing capital costs proportionally, thereby increasing revenues per dollar invested in capital costs. This optimization resulted in the elimination of 13 turbines (turbines numbered 1-7, and 45-50, as labeled in Appendix J). This modification resulted in a new 79.5 MW array, with an estimated average gross capacity factor of 36% for the site, and a net capacity factor of 32.5%. A reduction in capital cost, proportional to the reduction in overall project size, was assumed.

A base case scenario was developed within the economic model, based on most likely values for each of the cost, revenue, and financing variables that affect the project's economic performance. Sensitivity analysis was subsequently performed, varying these assumptions one at a time, to show the relative impact of each variation on overall estimated return on investment. High case and low scenarios were also developed to show what may happen if several key variables combine to improve or detract from project returns.

In the following sections of this chapter, the input assumptions to the economic model (the variables) are described. The chapter then describes the economic model results, and the results of the sensitivity analysis. In the following chapter, Task 8, overall conclusions, recommendations, and next steps are summarized.

Task 9 Results Summary

In brief, the economic model suggests that the modified 79.5 MW wind energy project will likely present economically attractive return on investment, under the assumptions outlined in this report. The results suggest that the proposed project merits further development effort. Sensitivity analysis results show that development effort should be prioritized to minimize financial risk, especially regarding the four "deal-breaker" variables: price of wind turbines, power sale price, annual energy production (capacity factor), and availability of grants and incentives.

The estimated return on investment, debt service coverage ratio, and assumptions regarding costs, revenues, and financing terms are considered sensitive and confidential information, not for public release. These details have been redacted from this document for public release. The economic model base case scenario estimates a project return on investment, with a minimum debt service coverage ratio,, and an average debt service coverage ratio, based on the following base case assumptions:

- *REDACTED*

In the following sections of this chapter, the input assumptions to the economic model (the variables) are described. The chapter then describes the economic model results, and the results of the sensitivity analysis. A prioritized project development plan and list of short-term and long-term next steps is included in the following chapter.

Financial Model Assumptions

This section describes the input assumptions to the economic model (the variables). These are organized into three categories: revenue assumptions, cost assumptions, and financing assumptions. The following sections of the report outline the base case assumptions for revenues, costs, and financing.

Revenue Assumptions:

The base case revenue assumptions are outlined below in Table 17: Base Case Revenue Assumptions. The major revenue assumptions include annual energy production (represented by capacity factor), electricity sale price, and the production tax credit (PTC) incentives. The discussion of electricity sale price below also includes a section characterizing the regional electricity market, and a section evaluating the drivers for expansion of renewable power.

Table 16: Base Case Revenue Assumptions for 79.5 MW array

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Annual Energy Production (Capacity Factor):

As discussed in detail in Task 1, for the 99 MW array, the predicted 80-m long-term mean annual array wind speed was equivalent to a gross capacity factor of about 34%. However, upon elimination of low-performing turbines, the gross capacity factor of the new 79.5 MW array is estimated at 36%. Several discount factors were included to convert the gross to the net capacity factor projections. The total discount is obtained from the product of the individual "efficiencies" (100% minus the loss) for each discount factor. For the 79.5 MW array, the total discount is estimated at 10.5% for the GE 1.5 xle. This calculation results in a net capacity factor of 32.5%. Annual energy production is then equivalent to what would be produced if the entire array were operating at full rated nameplate capacity for 32.5% of the hours of the year –226,600 MWh per year.

Electricity Sale Price

The discussion of electricity sale price is organized into three sections below:

- Electricity Sale Price Assumption for Economic Model
- Additional Information on Power Sales and Electricity Market Options
- Regulatory Influences on Market Conditions: Oregon Renewable Portfolio Standard

Electricity Sale Price Assumption for Economic Model

The actual price paid for power is highly case-specific, negotiated between the owner and the buyer in the power purchase agreement (PPA). Power from the proposed facility could be offered to a utility in response to a Request for Offers (RFO), whereby that utility procures renewable power to meet their RPS obligations. Alternatively, the project owner may choose to approach one or many utilities with an unsolicited offer.

For the purposes of the economic model, regional wholesale electricity prices and wind power prices were estimated based on FERC 1 reports, communications with utility representatives, and Lawrence Berkeley National Laboratory researchers with experience with nearby wind power facilities. Publicly available data on electricity pricing and forecasted electricity pricing in the region were also considered in electricity sale price estimates.[4]

The wholesale power prices for non-renewable sources in Oregon were in the range of $45-$50/MWh ($2007). Wind projects in Oregon, Washington, and Idaho have secured power purchase agreements up to $58.80/MWh (in 2006 nominal dollars) in the last eight years (between 1998-2006).[5] A wind power project in Idaho is reported to have signed a PPA with Pacificorp for $63/MWh in 2008. It is likely that the passage of SB 38 (the Oregon Renewable Portfolio Standard - RPS) will exert upward pressure on renewable power sale prices, as utilities struggle to meet their renewable energy procurement targets. Additional upward price pressure can be assumed due to Oregon's proximity and transmission capacity to California. Many transmission expansion projects are planned to support renewable power procurement by California utilities (for example the proposed PG&E Canada – Northwest – California CNC project, proposed as a double 500 kV AC and HV DC circuit, planned online date 2015, expected capacity 3000 MW from Boardman to the Tesla hub). Currently, the 2008 Market Price Referent for RPS solicitations in California is $105/MWh delivered in 2009 with a 15 year contract.[6] Much more renewable generation in Oregon may soon be shipped to California, causing a further increase in demand for the Oregon wind power.

For purposes of this report, the purchase price for delivered power was estimated. This is a premium for renewable power but a much higher premium is being seen in the California market. It is possible with planned grid improvements that the power from Warm Springs could be wheeled to California and the project could obtain a much higher sale price. If the project interconnects to one of the facilities not owned by WSPWE, a higher price may be needed to offset wheeling charges.

These estimates are based on industry standards and trends and on HDR experience with other energy development projects. There is no guarantee that WSPWE can secure a contract for the price that was estimated in the economic model base case. The economic analysis contained in this report should be modified once negotiations with utilities have begun and a more accurate estimate of the final negotiated electricity price can be obtained. The sensitivity analysis provides estimates of 10% higher and 25% lower electricity price contracts. Results are discussed in the "Sensitivity Analysis" section below.

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[4] Northwest Power Conservation Council, FERC 1 reports

[5] Personal communication with National Labs researchers.

[6] ENERGY DIVISION RESOLUTION E-4214, December 18, 2008. http://docs.cpuc.ca.gov/Published/Final_resolution/95553.htm

Additional Information on Power Sales and Electricity Market Options

The wind energy facility owner can sell electricity to any utility, under Oregon's 1999 restructuring law (SB 1149). Therefore, electricity should be sold to the utility that will give the best price and the longest term power purchase agreement (20 years or more is desirable in order to obtain a long-term loan). A preliminary market review is included below.

The Bonneville Power Administration (BPA), the northwest's major wholesale electricity provider, is another potential customer for power. If output from the project is sold to BPA along BPA transmission lines, the cost of electricity will decrease (wheeling charges will not be levied). However, the average wholesale power price in the northwest is low due to the prevalence of hydropower. BPA sells electricity at an adjusted wholesale (undelivered) rate of $26.90 to 68.45 per MWh for New Resources.[7] BPA also provides wholesale power customers with the opportunity to pay a premium for renewable energy credits. This Green Energy Premium (GEP) can range from $0-40/MWh and may allow the wind project developer to negotiate a higher price for electricity as a result of BPA's ability to charge a premium for renewable energy.[8]

Investor Owned Utilities (IOUs) will likely offer a higher price for wind electricity than Consumer Owned Utilities (COUs) or wholesale providers for several reasons. First, IOUs will have the greatest liability under the recently passed Renewable Portfolio Standard and have specific plans for expansion of renewable resources in their Integrated Resource Plans. For example, Pacificorp has issued a solicitation for 500 MW of renewable power in 2008, and they have identified a goal of 1400 MW by 2013. Finally, IOUs in Oregon also have pricing options for their customers to buy green power. As with BPA's GEP, green power purchase programs at both PGE and PacifiCorp increase the value of renewable electricity relative to power from fossil fuels sources. All of these factors contribute to an increased IOU appetite for renewable power purchase agreements.

The overall wholesale power costs for Portland Gen Electric (PGE) was $42/MWh in 2006 and $47/MWh in 2007. PacifiCorp averaged $44/MWh in 2006 and jumped to an average of $57/MWh in 2007. However, some additional price escalation should be anticipated due to the new Oregon RPS and due to high prices for renewable power delivered to California. PGE only covers Oregon and represents about 40% of Oregon's retail sales. Pacificorp covers Oregon, Utah, Washington, Idaho, and Wyoming. In Oregon, they account for about 31% of Oregon's retail sales.

The wind power project owner could also sell the project output to a third party power marketer, but this may be considered a less secure arrangement than a PPA by financial institutions, and this may make financing more difficult, or cause institutions to offer less favorable financing terms.

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[7] BPA, 2009. Current Power Rates. http://www.bpa.gov/power/psp/rates/current.shtml#footnote1.

[8] Ibid.

Regulatory Influences on Market Conditions: Oregon Renewable Portfolio Standard

A Renewable Portfolio Standard (RPS) is a state policy that mandates that a certain percentage of the electricity serving a state must be derived from renewable resources. The Renewable Portfolio Standard (RPS) passed in the Oregon Renewable Energy Act (SB 838) on May 23, 2007 requires Oregon's largest utilities to obtain 25% of their electricity from renewable sources by 2025.[9] Interim targets are set at 5% by 2011, 15% by 2015, and 20% by 2020. These targets can be met by ownership of qualifying resources – which includes wind, solar, wave, geothermal, biomass, and others – or by purchasing Renewable Energy Certificates (RECs). A REC is a certificate associated with one MWh of electricity generation from a renewable source and represents the green attributes of renewable electricity. RECs can be kept by the owner of renewable generation facilities to meet their RPS quota or sold.

This requirement will significantly increase the demand for renewable power in Oregon. The wind energy facility owner could potentially sell unbundled RECs (separate from their associated MWh of electricity) independently to any utility with liability under the RPS, or they could enter into a higher-price PPA and transfer ownership of the RECs (RECs bundled with electricity) to the utility that buys the electricity. Since the most likely buyers of electricity from the project (PacifiCorp and PGE) have liability under the RPS, the RECs will most likely be bundled with the electricity under the PPA.

[9] http://egov.oregon.gov/ENERGY/RENEW/docs/Oregon_RPS_Summary_June2007.pdf

Cost Assumptions

The major cost assumptions for the economic model include turbine price, road construction, interconnection fees, fixed and variable annual costs, and inflation. These all are bundled into the turnkey construction costs. The base case cost assumptions are shown in Table 18: Cost Assumptions. These assumptions are discussed in further detail in the sections below.

Table 17: Cost Assumptions for 79.5 MW array

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Turnkey Construction Costs

The total installed cost of the proposed 79.5 MW facility at the Mutton Mountain site is based on the engineering analysis and cost of equipment detailed in this study. Costs include access road improvements, turbine and tower equipment costs, equipment delivery and erection, labor and materials for design and construction of foundations, electrical collection system, environmental studies and permitting, interconnection, and other development costs.

Fixed and Variable Annual Costs

Annual non-variable or fixed costs include the following:

- Service warranty and parts,
- Equipment insurance,
- Management and administration, and
- Utilities for operations and maintenance.

For the Warm Springs project, this total cost was estimated.

Annual variable costs typically include the following:

- Operation and maintenance,
- Shaping and integration,
- Wheeling charges, and
- Other costs that are a function of the amount of electricity produced on the site.

Variable costs for the Mutton Mountain project were estimated. This includes current shaping and integration costs in the Northwest that increase at the same rate of inflation used to project other future costs. However, with increasing wind penetration in the coming years, shaping and integration costs may increase. This should be weighed during the power purchase agreement negotiations.

This variable cost estimate does not include the site specific wheeling charges, because it is assumed that WSPWE would sell the electricity to the owner of the transmission interconnection point. This assumption can also be changed in any sensitivity analysis if it becomes necessary to include wheeling charges.

Cost Notes

If the facility design is modified in the future, and total project capacity changed, the following notes will be important to keep in mind when modifying the capital cost in the economic model.

The project team has used a 79.5 MW project for the basis of analysis. However, most project costs are expected to be scalable on a per MW basis, regardless of project size. Scalable costs include turbine and tower, transportation costs, and interest accrued during construction.

Soft costs such as development activity, legal fees, and transportation cost estimates are expected to decrease on a per MW basis with increased project size because the fees are spread out across more equipment. The estimate for soft costs is based on industry standards and is expected to be spread out over the cost of the entire project, regardless of size.

Financing Assumptions

The major financing assumptions are the debt/equity split, corporate tax rate, depreciation, interest rate, loan term, and availability of federal or state grants. There are many ways to finance a wind development project. The financing assumptions have a significant impact on both the returns and the business development plan. The base case financing assumptions are detailed in Table 19: Financing Assumptions. The assumptions made in the base case of the pro forma analysis are discussed below. A detailed description of next steps for the different financing methods is provided later in the chapter.

Table 18: Financing Assumptions for 79.5 MW Array

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Land Lease Payments

Wind energy facility owners frequently lease land from the landowner. The structure of this lease varies from project to project, but landowners frequently receive royalties from developers equal to 2-3% of gross revenues from electricity sales. In the base case economic analysis, it was assumed that some fraction of annual electricity sale revenues, escalating with electricity price escalation, will be paid to the Tribes by the tax equity investor for the first 10 years, or until project ownership is "flipped" back to the Tribes.

Debt/Equity Split

For the purposes of the economic model, the base case project financing assumptions are as follows: some fraction of the capital costs are funded by debt and some fraction by equity from an investor with a tax appetite. A loan term and an interest rate is assumed. The debt and equity percentages can be changed in the pro-forma model. Terms for both debt and equity financing will ultimately depend on the tax equity partners and lenders and are typically not finalized until after a PPA has been signed. The "Project Development Plan" chapter following this chapter discusses deal structure options and funding sources in detail.

Federal Production Tax Credit

The Federal Production Tax Credit (PTC) is a tax credit, currently set at 2.1 cents per kWh.

The return on investment calculated in this analysis assumes that WSPWE or equivalent Tribal business entity will partner with an entity with significant federal tax liability to take advantage of the PTC. To do this, an entity with large federal tax liability will take majority ownership of the project (typically 90-99%) for at least the first ten years while the project is still eligible for the PTC. This entity will receive a tax credit in the amount of 2.1 cents per kilowatt-hour generated. A more detailed discussion of this ownership structure is provided under the section entitled "Next Steps and Business Strategy." If a partner with a tax appetite cannot be found then the Tribes may be eligible to pursue the grant in lieu of the tax credit under the American Recovery and Reinvestment Tax Act of 2009.

Federal Accelerated Depreciation Deduction

Section 179 accelerated depreciation schedule is another federal tax incentive available to most wind projects. [10] Depreciation is the annual deduction that allows tax payers to recover the cost of their business or investment property over a certain number of years. A normal straight line depreciation schedule would allow an owner of an investment lasting 20 years to deduct 5 % of the investment's value from their taxable income each year. The "Modified Accelerated Cost Recovery System" (MACRS) allows the owner of certain types of properties, including certain energy facilities, to depreciate their investment over a much shorter timeframe than the service life of the investment (standard depreciation). Wind currently falls into the five-year property class in MACRS.

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[10] Internal Revenue Service, 2006. Instructions for Form 4562 Depreciation and Amortization. U.S. Department of the Treasury.

There are even more greatly accelerated appreciation schedules available to qualified properties on Indian reservations, as long as they are placed in service before 2008. Were this provision to be extended, a wind project owned by WSPWE would qualify for a three-year recovery period. However, due to the in service deadline of 2008, this analysis assumes that the facility is eligible for an accelerated depreciation schedule of five years and that an equity partner with federal tax liability is able to take advantage of this deduction. In 2007, the five year recovery period MACRS schedule was 20% in the first year, 32% in the second, 19% in the third, 12% in the fourth and fifth, and 6% in the sixth. This schedule is assumed for the purposes of the financial model in this report.

Tax Assumptions

The financial incentives outlined above rely on the assumption that a project owner or partner has significant federal tax liability to be able to take advantage of federal tax credits and deductions.

Task 9 Conclusions: Financial Model Results

The total revenue generated by the project will be a function of turbine performance and actual electricity generation; however, revenue estimates were made based on the average capacity factor values determined by meterologists using industry standard statistical methods in the wind resource assessment. At the assumed electricity sale price, and with the meteorological and financial assumptions outlined in Task 1 of in this report, the 79.5 MW project was estimated to generate adequate electricity revenues to make return on investment attractive. This revenue stream would increase at the escalation rate that is negotiated in the PPA. Again, it is important to note that this is only an estimated revenue stream based on models of annual electricity generation and best available data on electricity price. This estimate should be updated when a more accurate electricity sale price estimate becomes available.

Estimated Return on Investment

Using the base case assumptions outlined above, the after tax return on investment was estimated. The detailed results of the pro forma analysis are included in Appendix Q. Sensitivity analysis results are included below in Figure 14.

While the site has several attractive characteristics including transmission interconnection options available, no significant wildlife or habitat impacts currently foreseen, and a 32.5% estimated annual average net capacity factor, the after tax return on investment depends heavily on the electricity price, capital costs and financing options. In order to enhance returns, additional steps should be taken to reduce turnkey costs, increase electricity price and take advantage of funding opportunities. These next steps are detailed in the following chapter.

Table 20 below shows the three scenarios for the economic analysis: the base case, the optimistic (high) case, and the pessimistic (low) case.

Table 19: Estimated Economic Returns – Base Case, Low Case, High Case

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The base case uses the assumptions outlined in detail in prior sections of this chapter. The high case assumes a 10% higher capacity factor, 10% higher electricity sale price, 10% lower turbine cost, 15% lower road cost, a certain size grant from DOE or other source and a low interest loan from New Market Tax Credit enhanced debt[11]. The low case assumes a 10% lower capacity factor, 10% lower electricity sale price, 10% higher turbine capital cost, 15% higher road cost, no grant money and no enhanced loan terms. These scenarios bracket the likely economic outcomes. The 20 year after-tax cash flows for the three cases are shown in Figure 14 below.

Figure 14: Warm Springs Wind Development Scenario Analysis for 79.5 MW Array

REDACTED

Sensitivity Analysis

In addition to the scenario analysis, HDR also used the economic model to run a sensitivity analysis on the major factors. The sensitivity analysis table below shows the relative importance of each of the variables, showing the relative impact of each variable on the project returns, and showing how the assumptions or the facility design may need to be modified to present an attractive return on investment. Each row in the table represents a version of the economic model, with base case assumptions, except for the variable noted. For example scenario 1 (S1) shows the base case return on investment. Scenario 2 (S2) shows the return on investment for all input assumptions the same as the base case, except for a 10% lower capacity factor. Scenario 3 (S3) shows the return on investment for all input assumptions the same as the base case, except for a 10% higher capacity factor. For each scenario, the assumptions are the same as the base case, except for the variable mentioned.

[11] The NMTC will be discussed in detail in the next chapter which discusses financing sources and deal structure.

Figure 15. Pro-Forma Sensitivity Analysis

	Project Sensitivity Analysis	After Tax IRR	Before Tax Leveraged IRR
S1	Base Case		
	Revenue Sensitivities		
	Capacity Factor		
S2	Low wind resource (10% lower capacity factor)		
S3	High wind resource (10% higher capacity factor)		
	Electricity price		
S4	Very low electricity price (25% lower)		
S5	Low electricity price (10% lower)		
S6	High electricity price (10% higher)		
S7	Very high electricity price (25% higher)		
	Capital Cost Sensitivity		
S8	25% higher WT cost		
S9	10% higher WT cost		
S10	10% lower WT cost		
S11	25% lower WT cost		
S12	15% higher road cost		
S13	15% lower road cost		
S14	Low interconnection cost (partially overground)		
	Financing Sensitivities		
	Loan Term Sensitivity		
S15	Loan term 5 yrs longer		
S16	Loan term 5 yrs shorter		
	Interest Rate Sensitivity		
S17	20% increase in interest rate		
S18	20% decrease in interest rate		
	Funding Sensitivity		
S19	NMTC $X allocation (Y% interest)*		
S20	NMTC $Y allocation (Z% interest)*		
S19	$A grant		
S20	$B grant		
S21	$C grant		

From this analysis it is clear that four variables – the cost of wind turbines, power sale price, capacity factor, and availability of grant funding – have the strongest impact on the project's returns. The difference between before tax and after tax IRR shows the impact of the tax related incentives, most notably the federal production tax credit.

This project may be an attractive investment opportunity, if capital costs can be minimized, and if revenue can be maximized through an attractive power purchase agreement and financing arrangement. The proposed wind energy facility is an opportunity for economic growth, clean renewable energy generation, atmospheric emissions reductions, and natural resource conservation for the surrounding community. This opinion of probable cost report provides the technical and economic basis for future development activity. It also represents the collaborative efforts of many stakeholders whose participation will be critical to ensuring project success. Many development activities require prompt action. In the next chapter, a detailed discussion of ownership options, financing deal structure, and priority next steps is provided.

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Chapter 9: Project Development Plan

Task 8 Description

HDR has prepared the project development plan outlined in this chapter to assist the Tribes in the decision-making process regarding the business structure for this project development, project ownership structure, and power marketing, and to identify next step activities.

Task 8 Activities

In the following sections several ownership strategies and four possible financing structures are identified, and the next steps needed for project development are summarized. The risks associated with each development step are identified, as well as mitigation strategies for these risks. An outline of next steps is provided. In the conclusion to this chapter recommendations regarding near-term priorities are provided.

Ownership Strategies

This section will provide an analysis of ownership options that the Tribes can consider and includes a discussion of potential risk and revenues to the Tribes under the different ownership options. Ownership structures are distinct from financing structures, which will be discussed in a later section called "Financing Structures". There are three business strategies that could be employed for the development of this wind energy facility:

- Land lease,
- Sole ownership
- Joint ownership.

In the lease strategy, the project would be owned by a developer who would negotiate a lease with the Tribes, including an upfront payment (depending on the project) and additional annual royalty payments (usually some fraction of annual revenues from electricity sales)[12]. In the tribal ownership strategy, the Tribes would form a legally separate Tribal business entity to develop, own, and operate the wind power project. In the joint ownership strategy, the Tribes would negotiate a joint venture with a tax paying equity partner in order to take advantage of the Production Tax Credits (PTC).

Option A: Lease Land for External Project Ownership:

In this scenario, the developer assumes responsibility for financing, implementing, owning, and operating the project, and decommissioning the project at the end of its useful life. The Tribes would likely issue an RFP to solicit design, build, own, and operate proposals from wind energy developers. Under this approach the Tribes' revenue would be limited to some type of upfront payment, plus ongoing royalty and rental

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[12] More information about lease terms can be found through the New York State Energy Research and Development authority's Power Naturally program at http://www.powernaturally.org/Programs/Wind/toolkit/14a_LeaseAgreements.pdf

payments. A typical lease rental rate is $2.00 per acre per year. Royalties are generally in the range of 2-4% of annual electricity revenues. Therefore, this option is tied to the size of the project, the power sales rate, and the capacity factor.

Option B: Wholly Tribally-Owned Facility:

Historically, tribal enterprises have been formed either under the Tribes' Constitution and bylaws that empower the Tribal Council to charter subordinate organizations for economic purposes, or under the Tribes' Federal Corporate Charter which authorizes the tribal membership, by referendum, to establish enterprises to be governed by a Plan of Operation adopted by the Tribal Council. Both of these types of enterprises are considered political subdivisions of the Tribes and have governmental attributes, such as sovereign immunity. Over the last 40+ years all major developments on the Warm Springs Reservation have followed this model. The Tribes is now considering the use of non-governmental entities to carry out some future development opportunities. It is also using a Delaware LLC to carry out its biomass electrical generation development project, and has enacted its own LLC statute authorizing the formation of tribally chartered LLCs that can be used by either the Tribes or its members. Lending transactions are complicated by the inability of the Tribes to pledge any interests in trust property, including trust lands, as collateral. Accordingly, alternative forms of collateral to secure the loans must be pledged. This typically takes a variety of forms including such items as power purchase agreements, letters of credit, and cash reserves, all of which have been used by the Tribes in its commercial transactions.

However, since the Tribes have no federal tax appetite, the Tribes would forego the additional revenue stream of 2.1 cents per kWh provided by the federal production tax credit without an outside investor. Under a typical arrangement the Tribes contract out the development of the wind power project to a private entity such that the contractor builds the facility on a turn-key basis. The developer assumes the risk of cost overruns, delays, and specified performance risks. Once the facility is commissioned satisfactorily, title is transferred to the Tribes at a predetermined price at closing of the permanent financing. The private entity, however, typically continues to operate the facility on behalf of the Tribes under a separate long-term operating agreement with a term of 5 to 10 years.

The current financing environment may make full tribal ownership challenging. In order for this to be a real option, the Tribes would have to obtain substantial DOE grants and/or loan guarantees in order to improve the returns for other investors or to fund the project without outside investors. There are significant funds for this type of project included in the recently enacted American Recovery and Reinvestment Act of 2009 (the stimulus package) and Tribes are specifically named as eligible entities; however, it is too early to accurately assess the impact that this funding may have on this project.

Option C: Joint Ownership with a Taxpaying Partner:

In the third option the Tribes would identify a tax equity partner with whom they would jointly own the project. There are several types of joint development agreements that have been used in wind development. It is common in the wind industry for developers to obtain concession contracts to develop the wind power project, with conditions that eventually return the ownership to the community or local government after a specified period. This enables the developer to receive a return on its investment and risk, and it provides options for the Tribes to invest its own funds initially and earn a prorated share of the returns. In this scenario, the Tribes select a private company to develop, finance, build, own and operate the power project for a designated period of time. After the contract term has been completed, the project ownership is transferred back to the Tribes without compensation or at a depreciated value. The longer the term of the agreement, the lower the project value becomes at the time of transfer. The private developer's ownership is typically fixed at 10 to 15 years, but could be longer depending on the initial investment. This equity flip structure requires the developer to have a 99% ownership stake in the project over at least the ten year tax credit period in order to take full advantage of the credits.

Financing Structure

In addition to determining which ownership structure best fits the Tribes' interests, it is also necessary to develop a financing plan. The deal structures discussed below utilize various different sources of debt and equity to cover the project cost. This section gives a brief description of the sources of debt and equity financing and then offers several sample deal structures. Several tax credits are available which can boost the return on investment for the project. Most of these tax credits are only available for a project partner with a tax appetite. However, some can be passed through to the Tribes from outside partners with a tax appetite. Tax equity partners can be expected to put at least the net present value of their future tax credits into the project as upfront equity. If returns on the project are attractive, then investors may provide additional equity or debt.

Production Tax Credit:

The federal production tax credit provides $21/MWh in tax credits for the first 10 years of operation. The 79.5 MW wind project is estimated to produce 226,600 MWh of electricity per year, which would deliver an annual tax credit of roughly $4,800,000. For the ten year period, this translates to a net present value of roughly $38M.

There are two critical issues with the PTCs: the in-service date and project ownership for tax eligibility. Regarding the in service date: the stimulus package includes a provision to extend the placed-in-service date for wind facilities through December 31, 2012 and to temporarily allow renewable energy production facilities to elect the investment tax credit (ITC) in lieu of the PTC. Converting the PTC to ITC may be an attractive option depending upon the tax situation of the tax-equity partner. Production tax credits provide credits based on the amount of energy produced each year. This best suits a partner with a projected ongoing profitability over the ten year period. Converting the PTC to the ITC may be an attractive option if the tax equity partner's future profitability is questionable, since the ITC provides credits based on the amount of money invested in a project.

However, more importantly the bill provides the option to apply for grants in lieu of tax credits for certain specified energy property which is placed in service in 2009 or 2010. A taxpayer must apply to the Secretary of Energy in order to receive the grant. Therefore, the Tribes would still require a financial partner in order to take advantage of the grants. The Secretary of Energy would provide the grants within 60 days of the application and the application must be received before October 1, 2011. The grants are theoretically to be designed to function in the same manner as the tax credits and be "off-the-shelf" in nature. The grant would be 30% of the basis of a wind project.[13]

The PTC and other federal incentives are likely to be the largest available to wind projects, and if possible, the project should use these federal incentives to their fullest extent. In order to take full advantage of the PTC or ITC credit, an external tax credit investor must hold a 99% ownership stake in the project over the ten year tax credit period. A Tribally owned enterprise could use the 10 year equity flip structure to harness the PTCs.

New Market Tax Credits:

Part of the Community Renewal Tax Relief Act of 2000, the New Market Tax Credit Program directs investments into privately managed investment institutions. In turn, these privately managed investment institutions, or Community Development Entities (CDEs), make loans and capital investments in businesses in underserved areas. By making an investment in a CDE, an individual or corporate investor can receive a tax credit worth 39 percent (30 percent net present value) of the initial investment, distributed over 7 years, along with any anticipated return on their investment in the CDE. Unlike the production tax credit, this is not tied to the performance of the wind project.

The NMTC Program permits taxpayers to claim a credit against Federal income taxes for Qualified Equity Investments (QEIs) made to acquire stock or a capital interest in designated Community Development Entities (CDEs). These designated CDEs must use substantially all (defined as 85 percent) of these proceeds to make Qualified Low-Income Community Investments (QLICIs). The investor, or a subsequent purchaser, is provided with a tax credit claimed over seven years. The investor receives a tax credit equal to five percent of the total amount paid for the capital interest or stock purchase over the first 3 years. For the final four years, the value of the tax credit is six percent annually. The Community Development Financial Institutions Fund (CDFI Fund) certifies CDEs on an ongoing basis, and allocates NMTC Allocations annually to select CDEs through a competitive application process.

New Market Tax credit can be used as tax credit equity or as a subsidized low interest debt instrument. An equity investment would use the discounted price for the seven years of tax credits up front. For example, a $100M loan invested through a CDE would generate $39M in tax credits. The investor would pay the discounted price for the tax credits which would be roughly $30M. Alternatively, the lender could pass on a portion of its NMTC benefit to the borrower through a reduction in the interest rate, which could

[13] "House Ways and Means Committee Releases Stimulus Bill". Hunton and Williams Update. January 2009.

lower debt service and subsidize rental rates for the first seven years. The New Market Tax Credit was designed to enhance projects that have some positive economic return, but which may not be strong enough for traditional financing. Accordingly, this may be an appropriate method for the Project.

Combining NMTCs with the PTC:

A renewable energy project that is eligible for Section 45 tax credits can utilize both NMTCs and the production tax credits from the project. Unlike other grant or subsidized loan programs, there would be no reduction in the available production tax credits from the project. If the CDE is providing debt to the project, then the investors in the CDE can claim the NMTCs while equity investors in the project can claim the PTCs. If the CDE is providing equity support to the project (less typical because the Treasury strongly favors CDEs that aren't "related" to the businesses they invest in), then the investors in the CDE can claim both the NMTCs and their proportionate share of the PTCs.

Depreciation Benefits:

The project offers significant depreciation benefits, including the opportunity to utilize accelerated depreciation. The Tribes is a tax exempt entity and cannot utilize these depreciation benefits. However, particularly in conjunction with securing PTC benefits, an equity investor could harness these depreciation benefits.

Oregon Business Energy Tax Credit (BETC):

This state tax credit is a vital component of the project. The project may qualify for this tax credit and would be able to pass the tax benefit (10% of the basis value, for five years in state income tax credits) to a third party in exchange for a state determined 33.5% pass-through value.

Oregon has also been discussing the development of a Business Energy Tax Credit (BETC) Energy Fund. This concept addresses the concern that companies without a tax liability can't find BETC pass-through partners. This proposal would create a fund to take the place of a pass-though partner. Individuals or a corporation would make a contribution to the fund and then projects would withdraw from the fund. The concept should be revenue neutral.[14]

[14] In addition to the BETC, the project may be eligible for the Small Energy Loan Program (SELP). SELP is administered by the Oregon Department of Energy and was created in 1981 after voters approved a constitutional amendment authorizing the sale of bonds to finance small scale, local energy projects. The sale of bonds is made on a periodic basis and, occasionally, to accommodate a particularly large loan request. Loans are available to individuals, businesses, schools, cities, counties, special districts, state and federal agencies, public corporations, cooperatives, tribes, and non-profits. Though there is no legal maximum loan, the size of loans generally ranges from $20,000 to $20 million. Terms vary, but are generally set to match the term of the bonds that funded the loans. Loan terms may not exceed project life.

Other Funding Sources:

Clean Renewable Energy Bonds (CREBs) present one possible finance option available to tribal governments. CREBs are bonds in which the Federal Government pays the interest, in the form of tax credits. An allocation of $800 million for CREBs was made in 2008. However, no announcement has yet been made by the IRS to accept applications for this allocation; therefore, it remains to be seen if this round of CREBs will be administered in the same manner as previous allocations.[15] However, it is assumed that future procedures will operate in a similar manner to previous rounds of funding as follows: The project owner is only responsible for repaying the principle amount and the bondholder receives tax credits in lieu of interest payments; therefore, CREBs act as an interest-free loan. A majority (95%) of the CREB allocation must be used on project capital expenditures. Also, the potential maximum size of the CREB allocation is not clear. Allocations are awarded to all eligible projects, starting with the smallest requested amount first, until all of the total CREB volume cap (approximately $300 million for non-governmental bodies) is allocated. One wind project received over $30 million during the first round of allocations; however, most projects were awarded much smaller amounts. It is possible that the project owner could secure some amount of tax free financing via a CREB allocation. The amount requested should balance the large size of the project with the desire to be competitive during the allocation process (projects requesting smaller amounts receive first awards).

The Oregon Energy Trust is a non-profit organization established to manage the funds that the two largest investor owned utilities, Portland General Electric and Pacific Power & Light (PacifiCorp), collect through a 3% public benefits charge assessed to ratepayers. It provides financial support to renewable energy projects on a case-by-case basis, based on the completeness of the development plan and the project's cost performance relative to the industry standard. To be eligible for funding from the Energy Trust, the project must be located within the service territory of PGE or PacifiCorp or the power from the project must be sold to one of the two utilities. The Energy Trust has provided anywhere from $100,000 to $4.5 million to wind projects.[16]

Funding support from the Energy Trust or Clean Renewable Energy Bonds is not included in the pro forma analysis; however, it is an avenue of funding that should be pursued.

Sample Deal Structures:

HDR developed a financial pro forma model which allows the user to split the equity and debt in project financing to demonstrate the impact of debt leverage on the returns for the project owner. The model currently assumes 15-year commercial debt at 6.5% interest. After discussions with potential New Market Tax Credit partners, additional analysis could be added to include detail regarding those terms. It should be noted that, the split of

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[15] DSIRE, 2009. Federal Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US45F&State=federal&currentpageid=1&ee=1&re=1

[16]. Personal Communication. Director of Renewable Energy, Oregon Energy Trust.

equity investment vs. debt financing does not necessarily dictate the ownership structure. So for example, the tax-equity partner may provide 50% of the financing but may have 99% ownership of the project for the first ten years. The returns estimated by the model are those that accrue to the project owner.

The example deal structures outlined below in Table 21 show how each of the funding sources outlined above might be allocated to meet the capital requirements of the project. These deal structures are only illustrative. The amount of money that is likely to be available from equity investors depends on the project's revenues and the associated financial return and the partner's tax situation. These returns could be enhanced by using NMTC enhanced debt to reduce debt service through reduced interest rates.

Table 20: Example Deal Structure Options

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Potential Risks and Risk Mitigation Strategies

The wind project development risk factors are split into major categories below. The typical sources of risk within each of these categories are described in the following table, along with key tools to help manage that risk. Though all of these risks can substantially impact the project, some are make or break factors. Ratings of risk levels shown in the tables below provide a sense of how much of a factor each risk plays in the overall project plan. A low risk rating can be mitigated with careful planning. High risk means that it is outside of the development team's control or that it should be evaluated early in the development process because it represents a potentially "fatal flaw".

Table 21: Financing Risk Factors

Risk	Description	Risk Level	Mitigation
Wind Resource – Capacity Factor	*The project's capacity factor – determined by wind resource assessments – is critical for financial viability. This input is critical for the pro-forma analysis and therefore the financial model is only as accurate as the wind resource assessment*	*High*	*Longer term and high quality wind resource assessment will reduce uncertainty. Monitoring towers should be distributed throughout the property and the turbine layout should be reconsidered if the capacity factor can be substantially improved.*
Electricity purchase price	*Securing a PPA at a good rate is a critical step for project development. The electricity sales revenue is critical for the project to have attractive returns for investors.*	*High*	*The project development team should start PPA discussions early and limit project development expenditures unless a favorable electricity sales price is likely.*
Turbine Cost	*Turbines represent the largest portion of the construction costs. The turbine prices proposed in this report seem high in comparison to historic pricing and commodity prices. Lower turbine costs are necessary to maintain financially attractive returns.*	*Medium*	*The project development team should compare turbine cost (including delivery) from the major turbine manufacturers as well as look for any distressed assets available for resale from other wind projects that are no longer moving forward.*
Operation and Maintenance	*Operation and maintenance of the turbines is critical to keep the turbines producing electricity and prevent outages.*	*Low*	*These risks can be mitigated by entering into a operations and maintenance contract and by hiring an experienced site manager*
Tax benefits	*The tax assumptions in the pro-forma model for the PTC, accelerated depreciation, and BETC are important revenue sources. Finding a tax equity partner will be critical. The current economic environment is making it difficult to find tax equity partners.*	*High*	*By the time the project has reached construction, there may be more tax equity investors available. However, since this is a critical component, the project management should work on finding potential partners and develop a plan for a successful equity drive.*

Natural disasters	*Lightning strikes, ice storms, mud slides and other unpredictable forces of nature can impact the electricity production of the project and could result in the loss of expensive equipment*	*Low*	*This can be mitigated by fully insuring the project assets. This will also most likely be required by investors before they provide financing.*

Table 22: Engineering and Construction Risk Factors

Risk	Description	Risk Level	Mitigation
Interconnection	*Without transmission capacity, the wind cannot be sold into the market. If there are significant capacity constraints, the project may need to be downsized.*	*Medium*	*The financial model assumes that the biomass interconnection design will leave enough additional capacity for the wind project. Additional interconnection studies and agreements are necessary to ensure the project has access.*
Road cost	*The terrain is more mountainous than typical wind projects. This will increase road costs and operation and maintenance.*	*Medium*	*Geotechnical studies are required to give a higher confidence level in cost estimates. In addition, an operation and maintenance company should be identified that has experience working in complex terrain, especially during winter conditions.*
Construction Management	*There are many interrelated steps in the construction schedule. Delays and poor management can increase costs or impact the start date. The start date is generally stipulated in financial, lending and PPA agreements. Breaking these contracts can have serious financial consequences.*	*Medium*	*Develop a construction contract that includes completion dates and penalties if the construction firm, turbine supplier, or materials supplier causes delays.*

Table 23: Legal Risk Factors

Risk	Description	Risk Level	Mitigation
Environmental studies and other permitting	*In addition to the environmental studies discussed in task 7, other permits may be required.*	*Medium*	*Early involvement of potential environmental critics and careful siting and layout can avoid problems.*
Tax treatment	*Tax treatment such as application of the PTC, accelerated depreciation and the BETC are complicated. Any false representation of tax liability to the IRS could seriously impede the project.*	*Medium*	*Consult both tax and legal professionals early in the project development and insure that the project is able to claim all the tax benefits that are described in the pro-forma analysis.*
Legal entity formation	*Forming an LLC is generally not a risk element, however forming a separate legal entity may be more of a challenge for the Tribes*	*Low*	*Take any "lessons learned" from historic formation of Tribal LLC's, for example the one formed for the proposed biomass project.*

Table 24: Management Risk Factors

Risk	Description	Risk Level	Mitigation
Identifying Development Team Members	*The project will require a dedicated development team to move from the drawing board to construction. Identifying a project champion and development team is important for the project's success*	*Low*	*Selecting a team that is experienced and that the Tribes trusts is critical. Take time to select your team and make sure the players can work together.*
Public Acceptance/Local Politics	*Objections to the project can range widely and are unpredictable. Issues include noise, scenic disturbance, and habitat disruption.*	*Medium*	*Sizing the project to minimize sound and visual impact can help limit the objections. The development team should consult with community members and other stakeholders early in the process to get buy-in.*
Site control	*It is necessary to secure control over the proposed project site to obtain permits, financing and some grants and incentives.*	*Low*	*The site is on tribal property. This ensures that no other entity can buy the property. However, it will be necessary to obtain approval and site control for the project in order to obtain financing and to ensure the project moves forward despite unforeseen public acceptance or local politics issues.*

It is critical to consider the risks labeled "high" in the tables above. These are potential fatal flaws and may significantly affect the project outcome. It will be important to pursue risk mitigation strategies for the risk factors labeled "high" to avoid unnecessary expenditures of time and money.

Task 8 Conclusions and Recommendations

The economic modeling results show that estimated returns on investment may be attractive for the proposed 79.5 MW facility, consisting of 53 turbines, at 1.5 MW each. Based on this modified design and cost analysis, there are now several steps that can be taken to minimize development risk, and potentially improve estimated economic returns. This should be the near-term focus for the project.

A summary of the recommended next steps is included below:

- Perform Geotechnical Investigations
- Perform Environmental Studies and Obtain Permits
- Obtain Turbine Supply Agreement
- File Interconnection Application
- Negotiate Power Purchase Agreement
- Develop Financing Plan
- Detailed Civil Design
- Detailed Electrical Design
- Select Construction Firm or Firms

First, geotechnical investigations, environmental studies, and permitting should be undertaken to minimize project development risks. This will minimize uncertainty regarding civil engineering costs and maintenance access, and uncertainty regarding potential environmental constraints.

Second, WSPWE should pursue a turbine supply agreement. Reducing turbine cost by $200/kw from the base case cost assumed in the economic model may increase the project returns by an additional 2%.This would also likely increase the amount of PTC equity investment available per turbine.

In parallel, negotiations regarding potential power purchase agreements (PPA) should be undertaken and interconnection applications should be filed. Strong regulatory drivers (for example the Oregon Renewable Portfolio Standard) may mean a premium electricity sale price could be obtained. In addition, if the power can be wheeled to California, through proposed transmission expansion projects), the renewable power would have a higher value in that high demand market. Increasing the electricity sale price by 13% may increase the project returns by over 2%.

Fourth, a financing plan should be developed including identification of a financial advisor and legal counsel, and identification of partners to take advantage of both New Market Tax Credit and Production Tax Credit[17]. This financing plan should include upcoming funding opportunities and deadlines, most notably the American Recovery and Reinvestment Act of 2009. This stimulus package could provide substantial grant funding or loan guarantees for

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[17] Or obtain grants from the DOE in lieu of the PTC under the new legislation enacted under the American Recovery and Reinvestment Act of 2009.

the Project. This bill was just signed into law at the time this report is being finalized; therefore, the full extent of the grants and loans available for this type of project are not yet defined. However, there will likely be substantial opportunities. Grants may improve the project returns by between 4-9%. Enhanced debt with a lower interest rate could also increase returns (by about 1-2%) for equity partners by reducing the interest payments.

If all of these improvements were made, the after tax return may be even more attractive to potential equity investors. After working to improve the estimated return on investment and assessing and mitigating high risk project development factors (especially legal factors[18]), the project team should move forward with the next steps for development.

Next Steps for Project Development

The process will have many interrelated and overlapping tasks which will require collaboration with businesses, government agencies, and legal review. Detailed organization during project development will allow the project manager to identify task dependencies and prioritize next steps. It is essential to develop a detailed project plan and timeline before advancing too far along in development. HDR has outlined some of the major next steps below.

1. **Improve wind resource knowledge by continuing on-site wind monitoring.** Team meteorologists have suggested that changing the location and distribution of the wind monitoring towers would improve the confidence in the wind energy calculations. The six towers originally installed on the Mutton Mountain and Shaniko Butte sites remain in service at the time of this writing, although one tower on Mutton Mountain was broken and replaced in October. Wind data is continually being gathered from these towers, to provide the longest possible historical meteorological record for this site. Current plans include installation of additional wind monitoring towers, of greater height, and potential expansion of wind monitoring to nearby sites for possible commercial expansion of wind development on the reservation. Sodar and LIDAR wind monitoring technologies are also under consideration at the time of this writing, to enhance the robustness of the wind data collected on the site, and to compensate for the absence of nearby long-term wind speed records for long-term predictive correlation.
2. **Perform Geotechnical Investigations**
    a. Soil/Rock borings for
    b. WTG foundations (66 locations plus 4 alternate locations)
    c. Transmission Corridor (25 miles for both options)
    d. Substation (36 miles- 2 per mile)
    e. Roadway Borings (36 miles- 2 per mile)
    f. Thermal Resistivity Sampling (36 miles)

[18] The team will most likely have to work with multiple attorneys with different areas of expertise to see the project through development. Specialized contracts are needed for power purchase agreements, turbine procurement, project financing, and land use. The Tribes may also need to hire attorneys who specialize in permitting and environmental compliance. In addition, the Tribes should consult attorneys experienced in corporate and tax law to make sure that the assets are protected should the project not perform as expected.

g. Geophysics (MASW & Resistivity)
h. Thermal Resistivity Testing
i. Laboratory Testing
j. Engineering Analysis and Report

3. Perform Environmental Studies and Obtain Permits

a. GIS Analysis and Mapping
b. Prepare Project Assessment Studies
c. Cultural Resources
d. Wetlands and Water Resources
e. Range and Agricultural Resources
f. Soil resources
g. Terrestrial Wildlife, Avian, Raptor, and Bat Studies
h. Prepare Permits and Approvals
i. Identify additoinal BIA requirements and procedures relevant to this project, if any.

4. Obtain Turbine Supply Agreement

a. Develop and deliver request for proposals from additional vendors. Consider warranty terms, turbine delivery, and other items included in equipment proposal as well (SCADA, VAR support, etc.)
b. Review proposals
c. Address clarifying questions and select vendor
d. Provide vendors with additional site/climate information
e. Turbine delivery route analysis may be required to determine which portions of existing infrastructure need to be avoided or modified.

5. File Interconnection Application

a. Select transmission interconnection point. HDR will conduct a study to determine optimal interconnection point – 230 kV line to proposed biomass circuit at warm springs, BPA 230 kV circuit, or other. This will depend on cost of line, market access provided by that line, and estimated wheeling charges on that line.
b. File interconnection application and perform system impact studies An interconnection request must be submitted to the relevant transmission owner (Bonneville Power Administration, PGE, or Pacificorp), to enter the Generation Interconnection Queue. This will initiate the study agreement process during which interconnection study requirements and completion timelines are negotiated. Further details and the expected deposit associated with each step in the interconnection process are outlined in the table below (Source: Large Generation Interconnection Procedures, BPA, 2007)

Table 25. Typical steps and deposits associated with each step in the interconnection process (Source: Large Generation Interconnection Procedures, BPA, 2007)

Interconnection Request	$10,000
Initial NEPA Study Agreement	$10,000
Interconnection Feasibility Study	$10,000
Interconnection System Impact Study	$50,000
Final NEPA Study	Varies
Interconnection Facilities Study	Greater of $100,000 or est. study cost
Construction, Site Control, Security Deposit	$250,000 (credited toward construction costs)

6. **Negotiate Power Purchase Agreement**
    a. Prepare project summary document to support PPA negotiations
    b. Identify power purchaser (set up meetings to circulate and discuss offer package with potential offtakers).
    c. Negotiate terms of power purchase agreement, power sale price and term/duration of agreement, wheeling charges if any. Obtaining an attractive power sale price is critical to improving estimated return on investment. The term of the PPA should be sufficiently long to amortize the project debt. The development team will seek a PPA of at least 20 years, to assure financing institutions that there will be electricity revenues for the life of the loan.
    d. Select legal counsel to assist with PPA negotiations as well as with incorporation of LLC and financing deal structure for tax law purposes
    e. Retain legal firm for the following tasks:
        i. Preliminary assistance with PPA negotiations
        ii. Assistance with incorporating LLC and structuring financing
        iii. Assistance with obtaining tax incentives
    f. Negotiations for the PPA can occur concurrently with, or even before, other development opportunities, as long as there are "off-ramp" provisions that allow the development team to terminate the power purchase agreement in the event of any unforeseen events that make the project infeasible. Off-ramp provisions usually include provisions for the inability to secure necessary transmission access, environmental approvals, project financing, or other critical project agreements.
    g. As utilities, such as PGE, Pacificorp, and BPA, issue Requests for Offers (RFOs) for renewable energy, the development team will initiate discussions offering electricity sale from this project. The development team may also approach potential offtakers with an unsolicited offer for renewable electricity sale.

7. **Develop Financing Plan**
    a. Obtain Tribal Council approval to proceed with joint ownership structure, with tax equity investor
    b. Identify investors, Production Tax Credit equity partners, New Market Tax Credit Partners
    c. Identify financial counsel
    d. Identify legal counsel
        i. See description above, in "Negotiate Power Purchase Agreement"
    e. Identify and begin discussions with potential tax equity partners that can take advantage of the production tax credit (PTC).
    f. Identify and begin discussions with potential community development entities (CDEs) that are funded under the New Market Tax Credit.
    g. Form joint venture or LLC business entity for project ownership and financing
    h. Identify deadlines for funding sources (tax credits, grants, loan guarantees, and other funding) and develop a priority list for application. Funding sources may include:
        i. DOE energy and infrastructure grants under the American Recovery and Reinvestment Act of 2009
        ii. Clean Renewable Energy Bonds.
        iii. New Market Tax Credits.
        iv. USDA Rural Development.
        v. Bond issuance
    i. Continually update the pro forma to support financing as needed and prepare financing documents and offering
8. **Detailed Civil Design**
    a. Aerial Survey
    b. Site Supplemental Ground Survey
    c. Design Vehicles
    d. Field Reviews
    e. Structure Investigation
    f. Hydrologic and Hydraulic Analysis
    g. Construction Logistics
    h. O&M Site Development
    i. Revising base mapping to include additional survey information provided by others
    j. Field review of the conceptual horizontal alignments by design engineers
    k. Hydraulic analysis for proposed drainage crossings
    l. Incorporation of geotechnical investigation recommendations into the final design
    m. Final engineering plans for the access road improvements (approx. 36 miles)
    n. Final engineering plans for the wind turbine site improvements
    o. Final engineering plans for crane paths, if necessary

p. Final engineering plans for improvements for an Operations and Maintenance site (excluding building design)
q. Processing the final engineering plans through the necessary approving agency
r. Revision of Opinion of Probable Cost for the roadway and civil site improvements
s. Preparation of construction specifications for the roadway and civil site improvements

9. **Detailed Electrical Design**
10. **Select Construction Firm or Firms**
11. **Develop a raw materials and equipment procurement plan**
12. **Turbine delivery route analysis may be required to determine which portions of existing infrastructure need to be avoided or modified.**