Preliminary Wind Turbine Feasibility Study

Prepared For:

MITSUBISHI CEMENT CORPORATION

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Executive Summary

The data presented in this preliminary wind turbine feasibility study indicates that wind generation is economically viable and worthy of a more detailed analysis. We have identified three locations that seem viable for installing wind turbines to serve a portion of the facility load. Two of these locations are on San Bernardino National Forest Service property. The third is in Lucerne Valley on property owned by Specialty Minerals Inc, an adjacent mine.

Mitsubishi Cement Corporation (MCC) has an electrical load of approximately 25 megawatts (MW). Electricity is currently purchased from a Direct Access (DA) provider. Transportation and Delivery (T&D) is by Southern California Edison (SCE) at the I-6 interruptible rate.

In this report we have assumed that the wind turbines will be connected “behind the meter” to displace electricity purchased at the retail rate. Regulatory considerations influenced the size of the potential projects that we evaluated.

For the two potential projects on National Forest Service property, we selected a size of 25 megawatts (MW) to minimize the export of electricity given MCC’s electrical load. Exported electricity will be valued at the utilities ‘avoided cost’ which is substantially lower than the MCC retail rate. The two National Forest Service projects are mutually exclusive. We could build one or the other, but not both.

We limited the size of the potential project on the adjacent Specialty Minerals mine to 5 MW because of two considerations: available land and standby charges. Specialty Minerals has limited land available for turbine siting. They have an interest in siting turbine(s) for their own load as well as for allowing MCC to site turbine(s) for the MCC load. The site will be evaluated as part of a more detailed study. The second reason for the 5 MW limit is that wind turbines are currently exempt from standby charges for projects of 5 MW or less.

We also analyzed an option for a 1 MW project. We selected this size for two reasons. One is that Net Metering is limited to projects of 1 MW or less. Net Metering projects are exempt from Departing Load or “Exit” Fees. Secondly, the Self Generation Incentive Program (SGIP) provides an incentive of $1,500/kW for the first 1 MW installed.

Table 1: Overview of Economics

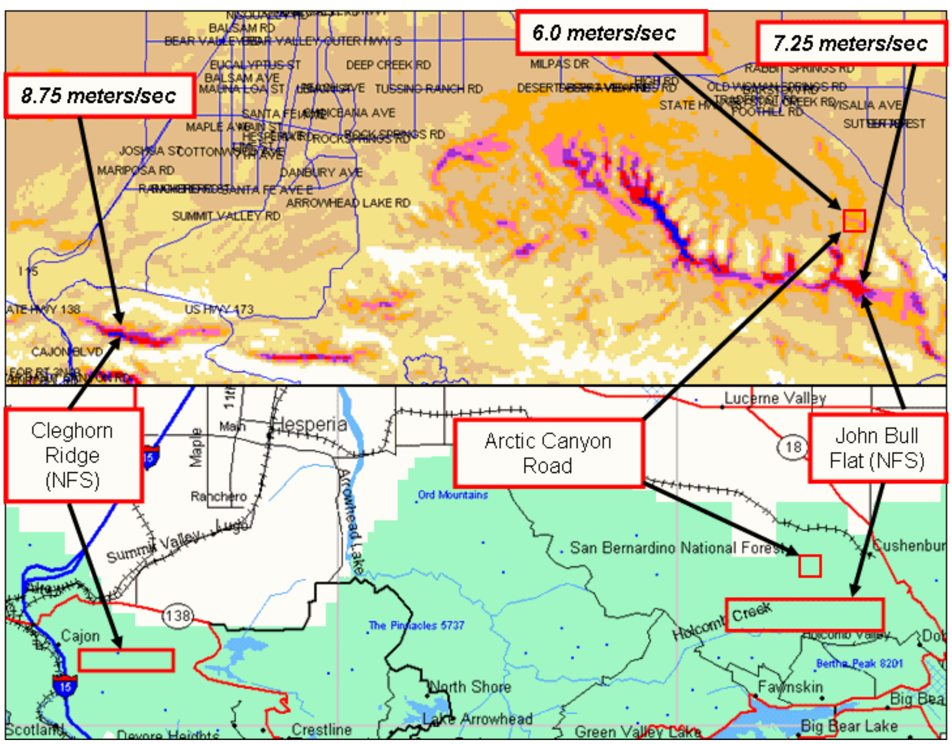
Location	Size (MW)	Distance from MCC (Miles)	Ave. Wind Speed (m/s)	Applicable Cost of Energy ($/kWh)	Installed Cost – NPV Basis ($)	Annual Savings ($/yr)	Payback (Years)
Cleghorn Ridge (NFS)	25	25	8.75	$.0565*	$19,125,000	$3,607,000***	5.3
John Bull Flat (NFS)	25	4	7.25	$.0680*	$18,144,000	$2,532,000***	7.2
Specialty Minerals Inc.	5	2	6.0	$.0830*	$3,988,000	$449,000	9.6
Specialty Minerals Inc.	1	2	6.0	$.0830*	$532,000**	$122,000	4.4

* Demand charges are excluded from Applicable Cost of Energy. Wind turbines are "intermittent" generators and they will not substantially reduce the demand charge which is based on the 15 minute monthly peak demand (kW).

** Installed cost reduced by state incentive (SGIP) of $1,500/kW which equates to $1,500,000 for a 1 MW turbine.

*** Annual Savings were reduced by $345,000/yr for SCE Standby Charge.

Some states completely exempt wind turbines from standby charges. This is based on the compelling argument that wind turbines will not substantially reduce a customer's demand charge. The benefits of demand (i.e. peak or capacity) reduction from wind turbines essentially accrue to the utility, not the customer. Many states have concluded that standby charges are essentially "double charging" and made wind turbines exempt. This issue deserves to be addressed in California.



Wind Map for Three Potential Locations

Electricity prices and the regulatory environment are changing substantially. DA energy costs ($/kWh) are typically based on Time of Use (TOU) pricing. In other words, different pricing for peak and off-peak use. However, for this preliminary study we ignore TOU pricing and use an average price for displaced energy of 9.3 cents/kWh based on information provided by MCC. A portion of this average cost includes demand ($/kW). To simplify the analysis we will assume that demand contributes 1.0 cents/kWh to the average so that the 'marginal' value for avoided electricity is 8.3 cents/kWh. Based on discussions with SCE and attorneys familiar with the current regulatory environment, we further reduced the value of avoided electricity for the following:

1. **Standby Charges** Currently exempt for 5 MW and below. For over 5 MW the Capacity Reservation Charge of $1,150/MW-Month (Schedule S - 50kV – 220 kV) applies to the entire installed nameplate capacity. For 25 MW this is $345,000/yr. We further reduced the avoided cost by 1.15 cents/kW for Backup Service.
2. **Departing Load Charge** This consists of six separate charges that total about 1.5 cents/kWh.

Details on these charges are discussed in Section 3.

We based our wind resource estimates on the California Energy Commission (CEC) wind resource maps and consultations with Rich Simon, a professional meteorologist who has over 20 years of experience in California. Energy production (kWh/yr) is based on a General Electric 1.5sls (1.5 MW) wind turbine with a 77 meter rotor diameter on an 80 meter tower for all scenarios except the 1 MW option. The 1 MW option is based on a Fuhrländer FL1000B (1 MW) wind turbine with a 60 meter rotor diameter on a 70 meter tower.

Section 10 covers the assumptions used in the financial analysis. We used a 'modified' payback analysis to simplify the comparison between different options. Although payback analysis has significant and well document flaws from a theoretical perspective, we use it here because it is intuitive. To eliminate some of the drawbacks of payback, we used the 'present value' concept to estimate the installed cost. We incorporated the substantial federal tax benefits (accelerated depreciation and tax credits) in present value terms and then compared this to the annual savings and expressed the result in terms of payback.

Below is a description of the three potential locations:

1. **John Bull Flat.** This land is located in the San Bernardino National Forest Service (NFS). John Bull Flat is near existing mines so it may be acceptable to the NFS. In this location, the turbines would be visible from nearby ski resorts but not from Big Bear Lake.

2. **Cleghorn Ridge.** This area has an exceptional wind resource. It will be very visible from Highway 15 and will draw strong opposition from small but vocal groups in the area. It is, however, an ideal location as there are no trees, there is an existing road along the ridge, and there is good wind exposure. Additionally, it is only about three miles from the railroad which seems like the most viable right of way for a transmission line. If the NFS is open to serious discussions regarding this site, then a parallel effort to identify transmission right of way should be commenced.
3. **Arctic Canyon Road.** The California Self Generation Incentive Program (SGIP) currently provides $1,500/kW for up to 1 MW. This applies to projects up to 5 MW but the incentive only applies to the first MW. For a 1 MW project, the $1,500,000 incentive payment would pay for a substantial portion of the installed cost including the roughly $200,000 required for above ground transmission. This option would require installing a private line over a public road. Although the regulations are subject to interpretation, the utility company can block it by refusing a utility interconnection. SCE will issue the SGIP incentive check only after the electrical interconnection is completed. Senate Bill 1727 seeks to clarify this situation. We are recommending the consideration of a joint project with Specialty Minerals and the installation of a meteorological tower (MET) as soon as possible to evaluate this option as the windy season is commencing. The cost for a MET is approximately $20,000. This should be considered a Phase I project with either of the larger projects above considered as Phase II.

For locations 1 and 2 above, we should focus our efforts on obtaining options on the land, then on installing MET's to confirm the wind resource. Discussions with the NFS are required to determine the viability of these two sites. A letter to the NFS requesting a dialogue about these projects was sent to the San Bernardino National Forest on March 17, 2006 and is included as Attachment D.

The Federal Production Tax Credit (PTC) of 1.9 cents/kWh (for 10 years) is only allowed by the Internal Revenue Service if the energy is sold via an "arms length transaction" between "unrelated parties". The PTC for large projects is typically worth 25% - 30% of the installed cost (on a 10 year NPV basis). This provides a substantial benefit to 3rd party ownership and operation of the wind turbines. Another advantage of 3rd party ownership is to leave the operation and maintenance of the turbines to a company with that expertise so that MCC can keep their focus on their primary business, not power generation.

The calculated payback periods provide a rough comparison of the four project options. A more detailed analysis should use IRR and NPV. As explained above it is generally preferable for a third party to own the turbines and sell power via a long-term contract called a Power Purchase Agreement (PPA). A PPA offer will typically include the cost of energy to MCC ($/kWh) and an annual energy escalation rate (%). These two numbers would then be compared MCC's current cost of energy and anticipated energy cost escalation. NPV is the preferred way to do this comparison and it will be used in a more detailed analysis.

Finally, there are several large wind developers that are interested in combining this project with a wholesale project to provide electricity to a utility. This would provide economies of scale that would reduce the EPC (Engineering, Procurement and Construction) costs as well as the O&M costs. We propose to evaluate this option as part of the more detailed study. In addition, we will investigate selling power to the other mines in Lucerne Valley to increase the size of the 'retail' portion of this project to further improve the economies of scale and the economics of the project.

Feasibility Study

1. Site Evaluation

Evaluate the proposed site concerning the general suitability for on-site wind energy generation with respect to the impacts of one or more wind turbine generators on Mitsubishi Cement Corporation's physical plant, daily operations, and the surrounding neighborhood.

The Mitsubishi Cement Corporation property is located near several areas of good wind. However, the actual plant property is either sheltered from the good winds or the terrain is too rugged for the economical installation of turbines.

When siting a wind turbine, we must consider a number of criteria to provide the most benefit to your facility and to minimize the potential negative impacts of a wind turbine on your neighbors. The proposed wind turbine site should:

- Provide the wind turbine generator (WTG) with exposure to the best wind and the least turbulence
- Maximize the positive visual impacts and minimize the negative on the facility and the surrounding area
- Minimize noise impacts on the facility and the adjoining property owners
- Not interfere with future facility expansion
- Minimize interconnection and wire run costs
- Provide proper setbacks from the highways and overhead utility lines
- Provide a good spot for public viewing and public information on the WTG system
- Provide adequate access for a crane and a suitable lay-down area for staging the tower, blades, and other WTG components for ease of construction and maintenance

The proposed site on the Specialty Minerals Inc property appears suitable for the installation of utility-scale wind turbines. We will evaluate this closely as part of a more detailed analysis. The two locations on the San Bernardino NFS land also appear to be suitable for turbines. The NFS will have to make the determination of the suitability the two areas for wind turbines. The NFS has committed to provide a response within 60 days. If the determination by the local office is unfavorable, we can appeal to the NFS headquarters in Washington DC. The information provided to the NFS is included as Attachment D.

2. Electrical Interconnection

Review Mitsubishi Cement Corporation's electrical drawings and inspect the existing electrical system to determine the most suitable point of electrical interconnection of wind driven generators to the Mitsubishi Cement Corporation facility and the scope and cost of any additional electrical equipment which may be required to connect one or more wind turbines to the Mitsubishi Cement Corporation electrical system.

Wind turbines in the class we are considering for this project utilize an electrical generator which typically produces three phase AC current typically at 690 volts AC. To offset retail rates and to be eligible for the California Self Generation Incentive Program, the wind turbine cable runs must be connected to the facility "behind the meter" which means at the facility distribution panel. For this installation we would connect the wind turbine to the facility through above ground power lines. The turbine voltage would be stepped up to the appropriate voltage considering factors such as line losses, costs and the actual facility interconnection voltage. Next, the wind turbine current passes through a utility accessible disconnect switch and a utility grade kilowatt hour meter before being connected directly to the facility distribution panel.

Interconnect Application (Rule 21)

California is one of the first states to have adopted a standard practice for the interconnection of distributed generation devices to the electric grid. Onsite generators must comply with the interconnection requirements set forth in Rule 21 of the utility tariff. Rule 21 says:

> "To remove unnecessary barriers to distributed generation deployment, the Commission adopted simplified and standardized interconnection requirements and associated fees governing interconnection of distributed generation facilities."
>
> www.energy.ca.gov/distgen/interconnection/CPUC_SECTION-2827.PDF

The interconnect application requirements can be seen on the following California Energy Commission website:

> www.energy.ca.gov/distgen/interconnection/application.html

Rule 21 specifies standard interconnection, operating, and metering requirements for distributed generation. Information on Rule 21 can be found on the following California Energy Commission website.

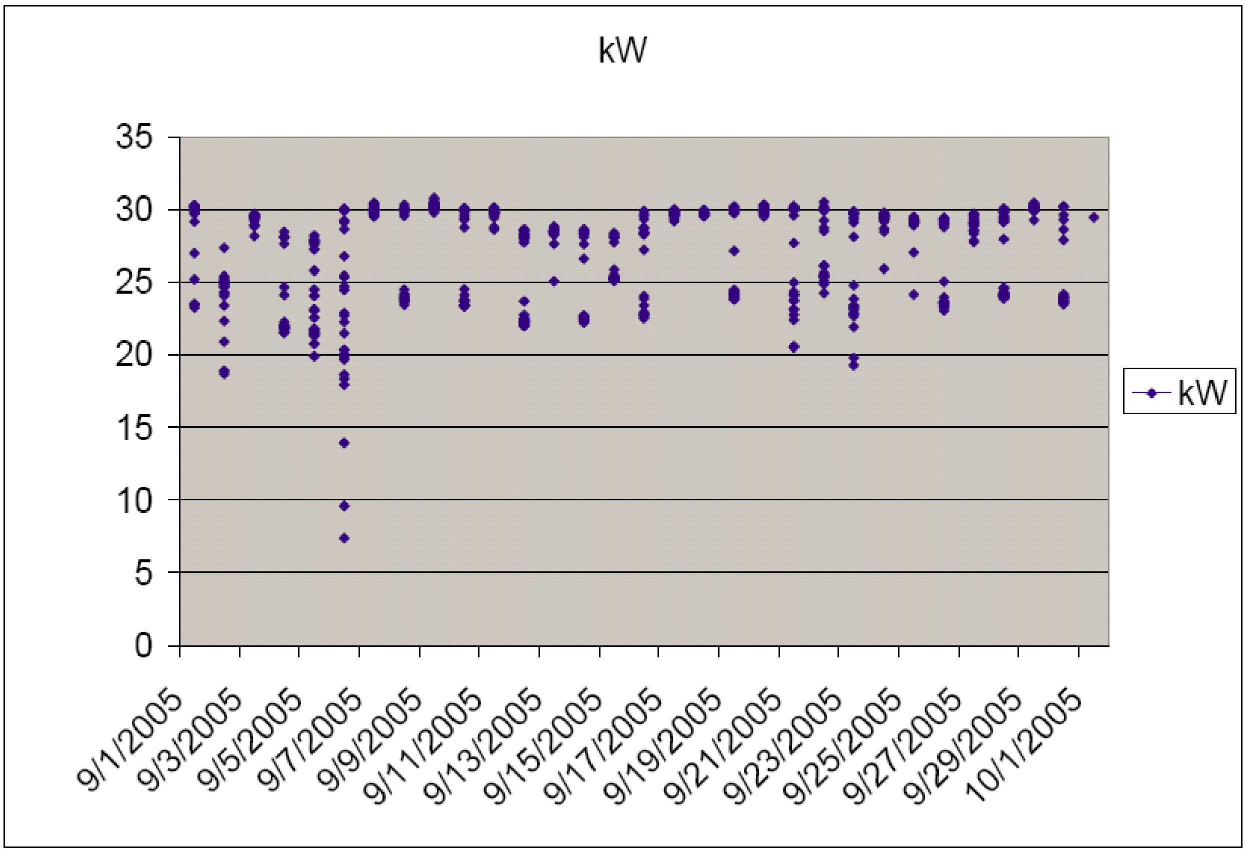
> www.energy.ca.gov/distgen/interconnection/california_requirements.html

An interconnect application will be submitted after an electrical engineer designs the system and creates a single line diagram.

3. Facility Cost of Energy

Collect and analyze electricity bills, determine cost of energy ($/kWh), yearly energy consumption, and electrical load profile.

The electrical load at MCC varies between approximately 20 and 30 MW. For the purposes of this study we will evaluate 25 MW of installed capacity. It is assumed that all of this power would be used 'behind the meter' and would be valued at the avoided retail energy costs. Exported electricity will be valued at the 'avoided cost' which is relatively low. As part of a more detailed study the annual load profile and wind profile will be evaluated and the installed turbine capacity selected to minimize exporting of power.



MCC Load Profile for September 2005

Determining the cost of energy will require a detailed analysis of the Direct Access contract which is beyond the scope of this study. To estimate the relevant cost of electricity we start with the average cost of electricity at 9.3 cents/kWh (data provided by MCC). Reductions to this rate were made for the following factors.

1. Demand Charges ($/kW) from DA provider
2. Standby Charges from SCE
3. Departing Load Charges from SCE

We discuss these components in detail below.

Demand Charges. For a large load customer such as MCC the demand charge is generally a relatively small portion of the entire average cost (annual bill divided by annual kWh). However, this is very dependent on the details of the DA contracts. We have assumed that demand contributes ***1.0 cents/kWh***.

Standby Charges. Energy users are currently exempt for 5 MW and below. For over 5 MW the standby charges apply to the entire installed nameplate capacity. The first 5 MW are not exempt if the project is over 5 MW. The SCE Standby (Schedule S) tariff does not have an interruptible rate so the benefits of the current (I-6) interruptible rate would essentially be lost for MCC after installing wind turbines. This may be corrected in the 2006 SCE rate filing. Standby charges consist of the following two components as defined in SCE Schedule S. The relevant portions of Schedule S are provided as Attachment E:

A. **Capacity Reservation Charge (page 2)**:
$1.15/kW of Standby Demand/Meter/Month. This equates to ***$13,800/MW*** per year. For 25 MW this equates to $345,000 per year.

B. **Backup Service (page 3)**
$.01721/kWh Energy Charge for Deliver Service. The cost for this will depend on the wind resource which, of course, varies from year to year. To understand this concept let's assume that the MCC load is 30 MW and constant and 25 MW of turbine nameplate capacity is installed. Let's look at a two-hour period. Assume that in the first hour the turbine output is 24 MW. For this hour SCE provides backup service for 1,000 kW's for one hour. The charge is $17.20 (1,000 kWh x $.01721/kWh) for this hour. Let's assume that in the second hour there is no wind. For this hour SCE provides backup service for 25,000 kWh's. The charge is $430.00 (25,000 kWh x $.0172/kWh) for this hour. Assume that the wind turbine has a Capacity Factor of 33% (330 kW overage for the year for 1,000 kW of nameplate capacity). This means that SCE is standing by for 67% of the energy. Therefore the relevant Energy Charge for Delivery Service is ***$.0115/kWh*** (.67 x $.0172/kWh).

Departing Load. Depending on several factors and interpretations MCC may be faced with the following Departing Load charges (or "Exit Fees) that are listed in the numerous and seemingly conflicting SCE tariffs.

Name	Current Rate	Applicable Tariff	Amount used in Analysis
NDC	$0.00048/kWh	Schedule S	$0.00048/kWh
PPPC	$0.00577/kWh	Schedule S	$0.00577/kWh
HPC	$0.01000/kWh	DA-CRS	$0.00100/kWh
CTC	$0.00650/kWh	DA-CRS	$.002500/kWh
DWRBC	$0.00485/kWh	DA-CRS	$0.00485/kWh
DWRPC	$0.00550/kWh	DA-CRS	$0.00000/kWh
		TOTAL	**$.014600/kWh**

The SCE Direct Access Cost Responsibility Surcharge (Schedule DA-CRS) is provided as Attachment F.

Below is a description of the different components

NDC (Nuclear Decommission Charge). The current charge of $.00048/kWh will be included in the analysis.

PPPC (Public Purpose Programs Charge). A separate charge that all electric customers are required to pay to fund various public purpose programs including:

1. Renewable resource energy technologies
2. Energy efficiency
3. Research, development and demonstration
4. Low-income programs

The current charge of $0.00577/kWh will be used in this analysis. However, it should be noted that it seems more likely that this charge will increase over time rather than decrease.

HPC (Historical Procurement Charge) is a nonbypassable charge to recover DA Customers' share of SCE's Procurement Related Obligations Account. This is a customer specific calculation and it depends on how much of the HPC obligation MCC has paid off. This charge will drop over time and the obligation may already be paid off. HPC will be assumed to be $0.001/kWh rather than the full $.01/kWh for this analysis.

CTC (Competition Transition Charge). Charge to recover the above market costs of utility retained generation. This is also referred to as the 'Tail CTC'. This charge is to pay for the 20 and 30 year contracts for ultra clean and low emissions that were negotiated primarily in the 1980's. This charge will drop over time. $.0025/kWh is used in the analysis instead of the full CTC cost of $0.0065/kWh.

DWRBC (Department of Water Resources Bond Charge). This bond charge is to recover the interest and principal of DWR bonds. Continuous DA customers are exempt from the DWR bond and power charge components of the Cost Responsibility Surcharge (CRS). Continuous DA customers are those that switched to DA service before February 1, 2001 (before DWR began its power purchases). It is assumed that MCC is not a Continuous DA customer. The current cost of $.00485/kWh is used in the analysis.

DWRPC (Department of Water Resources Power Charge). Charge to recover the DA Customers' share of DWR contracts costs after 2002. For purposes of Schedule DA-CRS, the power charge represents Direct Access customers' share of the DWR procurement costs beginning September 21, 2001. From discussions with SCE it appears that an exemption for this charge will be accepted. This charge has been omitted from the analysis.

Below is a list of the SCE tariffs that may be applicable:

Schedule I-6: Time-of-Use, General Service - Large - Interruptible

http://www.sce.com/NR/sc3/tm2/pdf/ce76-12.pdf

Schedule NEM: Net Energy Metering

http://www.sce.com/NR/sc3/tm2/pdf/ce158-12.pdf

Schedule DA-CRS: Direct Access Cost Responsibility Surcharge

http://www.sce.com/NR/sc3/tm2/pdf/ce144-12.pdf

Schedule DL-NBC: Departing Load Nonbypassable Charges

http://www.sce.com/NR/sc3/tm2/pdf/ce148-12.pdf

Schedule CGDL-CRS: Customer Generation Departing Load Cost Responsibility Surcharge

http://www.sce.com/NR/sc3/tm2/pdf/ce214-12.pdf

Several of the components listed above may be embedded in the current tariff. This will require more detailed analysis. For this analysis the Departing Load is assumed to be ***$.015/kWh***.

Summary of Facility Cost of Energy

For projects below 5 MW the Standby Charge does not apply. For a project of one megawatt or below the Net Metering tariff applies and this excludes the Departing Load Charge and all other charges. For all project sizes, savings for demand will not be included. It is assumed that the DA contract bases the demand cost on the peak power output in each month. Since wind is intermittent, it is difficult to calculate demand savings and the demand savings will certainly be small.

The following tables list the calculations of the estimated energy rates ($/kWh) and capacity charges ($/MW) used in this analysis.

25 MW (both NFS Projects)		
	Energy Cost ($/kWh)	Capacity ($/MW)
Average DA Energy Costs	$0.0930	
Demand Portion of Ave. Energy Cost	-$0.0100	
Standby (Capacity Reservation Charge)		$13,800
Standby (Backup Service)	-$0.0115	
Departing Load	-$0.0150	
	$0.0565	**$13,800**

5 MW - Specialty Minerals (Exempt from Standby)		
	Energy Cost ($/kWh)	Capacity ($/MW)
Average DA Energy Costs	$0.0930	
Demand Portion of Ave. Energy Cost	-$0.0100	
Standby (Capacity Reservation Charge)		$0
Standby (Backup Service)	$0.0000	
Departing Load	-$0.0150	
	$0.0680	**$0**

1 MW - Specialty Minerals - Net Metering (Exempt from Standby and Departing Load)		
	Energy Cost ($/kWh)	Capacity ($/MW)
Average DA Energy Costs	$0.0930	
Demand Portion of Ave. Energy Cost	-$0.0100	
Standby (Capacity Reservation Charge)		$0
Standby (Backup Service)	$0.0000	
Departing Load	$0.0000	
	$0.0830	**$0**

4. Climatic Conditions

Evaluate the local climatic conditions at the site such as sand, dust, turbulence, and hail.

The amount of energy that can be extracted from the air by a wind turbine depends on how fast the air is moving (wind speed) and to a lesser extent, how much it weighs (air density). The air density at the site depends on the altitude, temperature, and moisture content of the air. Air is denser at sea level than in the mountains. As elevation increases, the density of the air decreases by about 9% for every 1000 meters of elevation above sea level.

Other conditions which may affect wind turbine performance are airborne dust, insects, and ice formation. Dust and insects can cause a dirty film to build up on the blades effecting performance. Dust and insects do not typically require any additional maintenance as they are usually washed off by nature in periodical rain showers. Ice that forms during an ice storm, however, can significantly affect wind turbine performance. Wind turbine towers are very robust and are rarely damaged by ice.

Any ice build up on the wind turbine blades will change the shape of the airfoils and cause degradation in performance. An automatic safety shutdown of the wind turbine will occur as soon as the controller detects an icing condition. This fault condition will be transmitted to the wind turbine operator. The controller will not allow the turbine to restart until the operator has visually inspected the blades to make sure they are free of ice and has manually inserted a key to restart it.

The wind turbine generator and controller are designed to withstand extreme temperatures. Factory engineers will review the site survey data, which gives the extreme temperature ranges expected at the wind turbine location, and install the proper heating and cooling systems.

5. Optimal Turbine Location

Determine the optimal turbine location given the wind regime, topography, vegetation and prevailing winds. Other considerations used to determine the location include road access for turbine assembly, soil characteristics and your electrical system infrastructure.

The two areas of interest on the National Forest Service property have not been inspected. That is beyond the scope of this report. The area in Lucerne Valley and on Specialty Minerals Inc. property is on a gently sloping hill with a paved road. It appears suitable for crane and equipment access for erection. The site will be evaluated in more detail as part of a follow on study.

6. Special Applications

Complete the following for MCC to submit:

- FAA form 7460-1 (HTTP://oeaaa.faa.gov) application so that the FAA can perform an Obstruction Evaluation/Airport Airspace Analysis.
- Self Generation Incentive Program (SGIP) application to Southern California Edison (SCE) (currently $1,500/kW for up to 1 megawatt). The application will be completed and Debenham Energy, LLC will advise on when SCE will accept the application. Coordinate on-site meeting/presentation with SCE.
- Height variance, set-back variance and/or special use permit application(s) (as required) for the local controlling agency(s), if applicable.

These will be completed as part of a more detailed follow on study.

7. Wind Data

Locate nearby sources of long-term wind data (if possible) that will provide an accurate long-term estimate of the expected wind energy at the Mitsubishi Cement Corporation facility. This estimate will also include a review and comparison to known wind resources by a professional meteorologist with over 20 year of experience in California who has access to local wind data.

Accurately predicting the energy yield of one or more wind turbines at a proposed site requires knowing the local wind resource. Wind energy experts can provide this information with a high level of confidence using wind resource data available near and at the site.

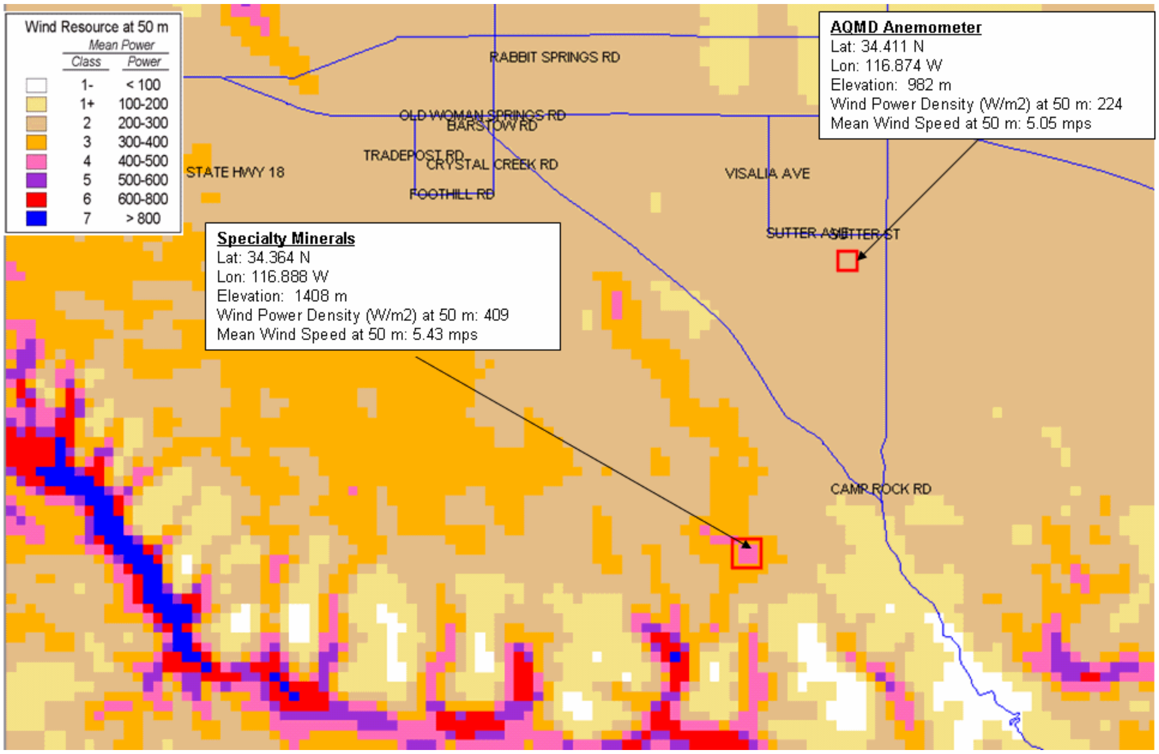
The following information helps identify good sites for wind energy harvesting:

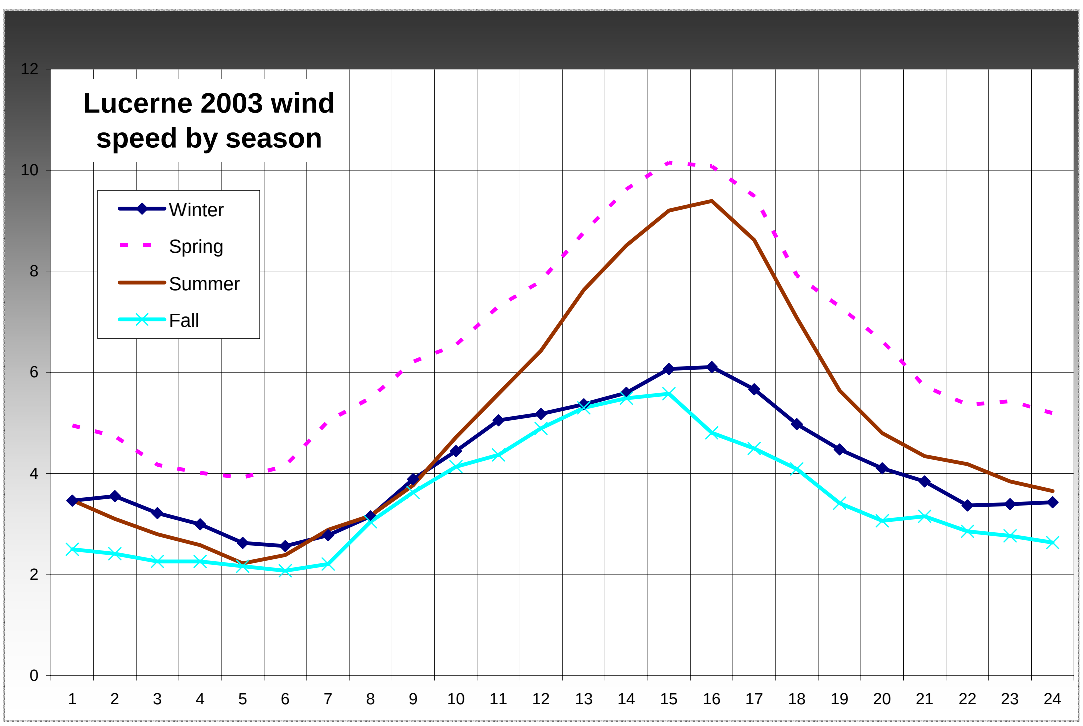
- Site characteristics such as wind flagged vegetation
- State and federally sponsored wind map models that help locate the windy areas of the state
- Nearby sources of wind data from airports, agricultural stations, or air quality monitoring stations
- Meteorological monitoring towers that provide wind data for a location at or near the site

High quality meteorological data does not exist in the vicinity of the three locations identified in the report. To accurately determine the viability of this project a meteorological tower (MET) must be installed in the selected area(s).

The wind resource estimates used in this report are based on the California wind resource maps and an analysis by Rich Simon, a professional meteorologist with over 20 years of experience in California. His resume is included as Attachment G. In addition, an Air Quality Management District anemometer in Lucerne Valley collected hourly data for four years. This data was used to estimate the wind resource at Specialty Minerals.

The wind map below shows the location of the AQMD anemometer relative to the Specialty Minerals location.





Information on the methodology used to generate the wind data and maps can be found on the website below:

www.awstruewind.com/inner/services/windmapping/mesomap/mesomap.htm

The AQMD hourly anemometer data shows the wind patterns. This diurnal (hourly) wind data was not used in the economic analysis since Time-of-Use cost data for the DA contract was not provided. The point to note is that the wind appears to coincide with the times of peak energy prices. This will be evaluated as part of a more detailed analysis.

8. Permitting Requirements

Determine applicable permitting requirements and identify the agencies with jurisdiction.

This will be evaluated as part of a more detailed follow-on study. In general, obtaining a building permit depends on local, county, state and federal regulations most of which are listed below.

- Federal Aviation Administration obstruction height and lighting
- State building and electrical codes
- Town or county zoning regulations
- State coastal regulations
  - Within the coastal zone
- State Dept. of Environmental Management regulations
  - Wetlands, or landfills
  - Wildlife areas
- Local historic district regulations
- State historic or cultural resource commissions
  - Designated historic area
  - Areas with archeological significance
  - Designated viewshed area
- Federal Land (BLM) or National Historic Register designation
- US Fish and Wildlife (in areas of designated critical habitat, endangered species or migratory birds)
- US Coast Guard (if wind turbine obstructs aids to navigation lighting)
- US DOD if wind turbine may interfere with radar or border listening post

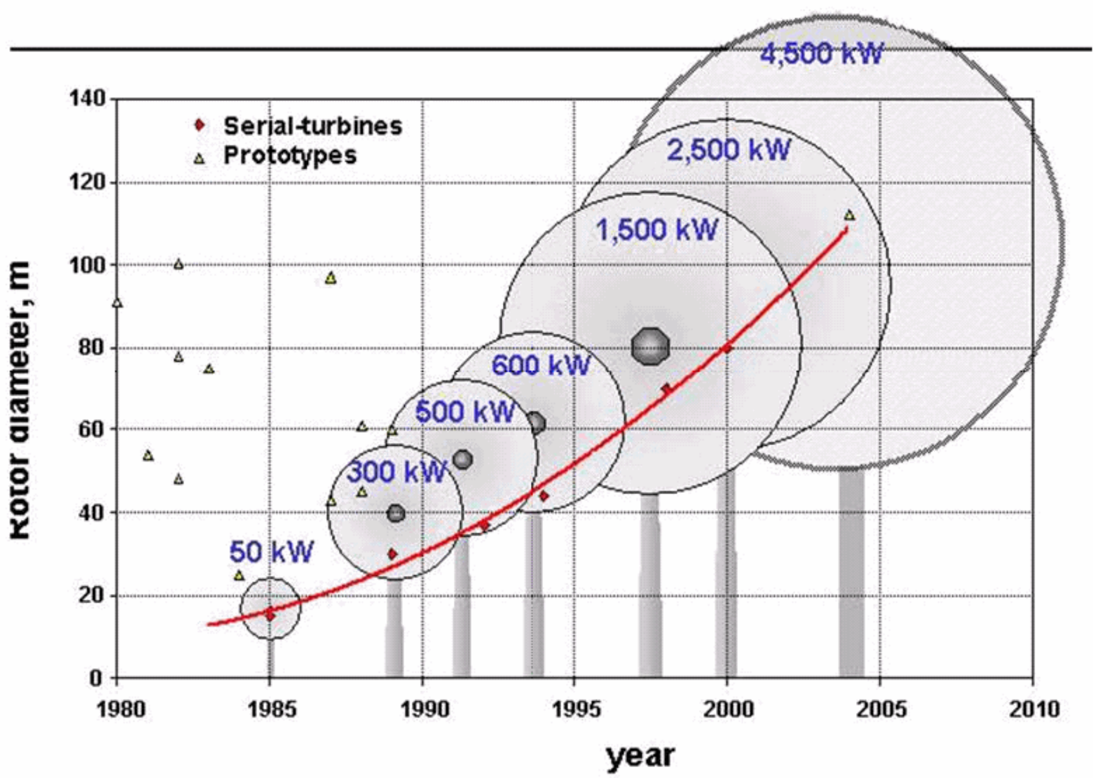
9. Turbine Model Recommendations

Determine the appropriate turbine model for the facility electrical load, allowable height and wind resource profile.

Matching an appropriately sized wind turbine to a given facility depends on the following factors:

- Facility electricity loads
- State Net Metering and Self Generation Incentive Program requirements which limit the allowable wind turbine size
- Size of the proposed wind turbine site and proximity to sensitive neighborhoods
- Availability of specific wind turbine models which fit the above criteria

Economies of scale have a large impact on wind energy economics which is why most turbine manufacturers are focusing on turbines larger than 2 MW. These turbines have rotor diameters of 100 meters and larger and they can be put on 100 meter towers. Larger turbines have lower equipment costs and higher power outputs per MW of installed capacity.



Wind Turbine Economies of Scale

Some factors can favor smaller turbines. These include:

- Costs of grading roads
- Cost of renting cranes. For a project with a small number of turbines it may be preferable to use 'smaller' turbines (1-1.5 MW).
- Regulatory and policy considerations. The state incentive program is limited to 1 MW. Also the Net Metering rule is limited to 1 MW. Net Metering projects are exempt from departing load, standby, customer, minimum monthly, interconnection and other charges.

For the two larger (25 MW) potential projects on NFS land 1.5 MW turbines will be evaluated. Road access may preclude larger turbines. For the smaller potential project on Specialty Minerals Inc property a 1 MW and three 1.5 MW turbines will be evaluated. We considered the available land and the desire to stay below the 5 MW (exempt from standby charges) in this selection. There is a point where savings from the economies of scale will offset not having the state incentive that is only available on the first MW and Departing Load Charges that apply for projects greater than 1 MW (non Net Metered). We will know after wind data is collected at this site and the site has been evaluated if it is worth evaluating two 2.5 MW turbines.

10. Comprehensive Economic Model

Provide a comprehensive economic model for the installation and operation of one or more wind turbines at MCC's site that will utilize the information compiled to give MCC a concise picture of the economic benefits that the project will provide.

We used a 'modified' payback analysis to simplify the comparison of different options. Although payback analysis has significant and well document flaws we use it here because it is intuitive. To eliminate some of the drawbacks we used the 'present value' concept to estimate the installed cost. We incorporated the substantial long term tax benefits (accelerated depreciation and tax credits) in present value terms to estimate the "after tax" installed costs. This was then divided into the net annual savings in order to calculate the payback.

The federal government provides two very significant tax incentives to encourage the development of wind energy projects. These incentives are:

1. Federal Modified Accelerated Cost Reduction System (MACRS) allows the capital costs of a wind turbine project to be depreciated over five years using a 200% declining balance method
2. Federal Production Tax Credit (PTC) is a tax credit for actual power produced (1.9 ¢/kWh, adjusted for inflation) for the first ten years' electricity output from a qualified privately-owned wind generation facility

The accelerated depreciation benefits can be worth 25%-30% of the installed cost (on a 5 year NPV basis). The PTC for large projects is typically worth 25% - 30% of the installed cost (on a 10 year NPV basis). The PTC is only allowed by the Internal Revenue Service if the energy is sold via an "arms length transaction" between "unrelated parties". For this reason it is preferable for a 3rd party to own and operate the wind turbines. Another reason for 3rd party to own and operate the equipment is that, unlike MCC, it is their core competency.

Obtaining site specific estimates for installation is beyond the scope of this preliminary analysis. Instead commonly used rules-of-thumb and assumptions based on site specific factors were used to estimate the installed costs. The assumptions and calculation of the payback is provided on the last page of this section.

The costs for installing, operating and maintaining a wind turbine are determined by a variety of factors. These factors are described below in general terms.

Installation Costs

Major categories of installed equipment costs include:

- Turbine
  - Turbine and Tower
  - Freight
  - FAA Lighting
- Balance of Plant
  - Site Development
  - Pad Mount Transformer
  - Concrete and Rebar
  - Foundation Labor
  - Tower Imbeds / Bolts
  - Cranes, Crane & Erection Labor
  - Construction Supervision
  - Monitoring and Control System
- Interconnection
  - Electrical Wiring (turbine to facility)
  - Interconnection and Metering
  - Electrical Labor
- Soft Costs
  - Legal
  - Permitting
  - Development & Engineering
  - Insurance
  - Meteorological Tower (if required) and Feasibility Study
  - Contingency

A contingency typically includes the cost of items that are subject to change. By having several items in the contingency it is possible to get the benefits of diversification since some items will be higher than projected and some lower. This diversification eliminates the need to add the worst case estimates together. This is a good number to have in mind if the probability of it occurring is understood. Cost elements that should be included in a contingency are:

- **Exchange Rate**. Most suppliers of wind turbines are European. International sourcing includes a risk of exchange rate variations. As the time of sale approaches, a contract to purchase the Euros required to buy the wind turbine can be purchased at a fixed cost. This risk can be mitigated by obtaining a turbine quote that is valid for 30 days or possibly longer.
- **Cost of Steel and Copper**. Commodity prices have been high and volatile recently. This includes steel and copper which are large cost elements of a wind turbine project. A practical approach to mitigate this risk is to obtain quotes valid for 30 days or possibly longer.
- **Turbine Prices**. The high demand for wind turbines in the U.S. and internationally has caused a price rise of almost 20% over the last year.
- **Miscellaneous.** This could include foundation and electrical trenching costs (e.g. hitting rock), inclement weather requiring more time for the crane and crew to be at site, and a general adder for unforeseen occurrences.

Operating Costs

While there are no fuel costs for a wind turbine, there are ongoing operating costs associated with maintenance and other aspects. These cost elements include:

- Operations and Maintenance
- Warranty
- Equipment Repair and Replacement Fund
- Property Taxes
- Equipment Insurance
- Management / Administrative
- Land Lease (only relevant if a third party owns the wind turbine)
- Miscellaneous

It is common to get a fixed price contract for operations and scheduled maintenance. It is not economically viable to get a fixed price contract for unscheduled maintenance and repair (after the warranty period). We used a sinking fund method to estimate the annual operations, maintenance and repair costs. This same method was used for the Victorville Federal Prison project. The Federal Government required that funds be set aside to cover a potentially large repair cost at an unknown time in the future. This method involves estimating the long-term operations, maintenance and repair costs and equating that to an equivalent annual amount that would be deposited into the sinking fund each year. This method allows the equivalent annual maintenance cost to be subtracted from the annual energy savings to calculate the yearly cash flow from the wind turbines. The 'present value' of the installed cost is divided into this to calculate the payback.

A good explanation of maintenance cost drivers is included in Attachment H: *Long-Term O&M Costs of Wind Turbines Based on Failure Rates and Repair Costs*.

Estimating Electric Bill Reduction

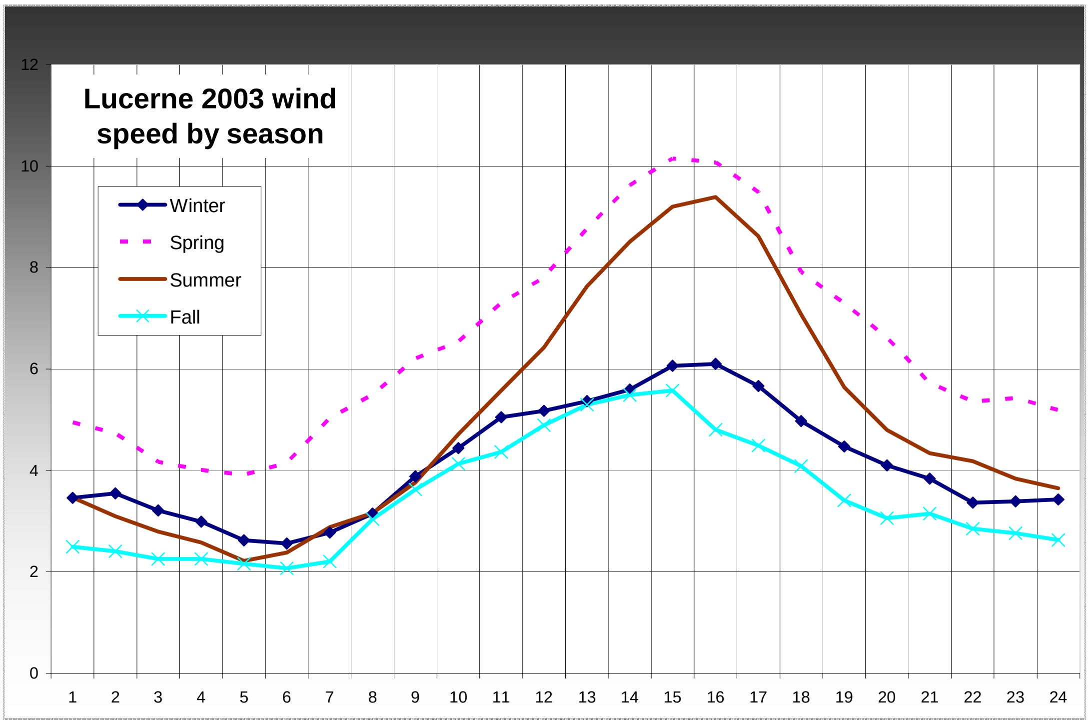
An electric bill from SCE contains four types of charges:

- Customer Charges
- Demand (kW) Charges
- Energy (kWh) Charges
- Other (e.g., metering, interconnection study)

Customer, Demand, and Other charges all are considered pure utility wire charges. The energy charges are a mixture of wire and generation charges. While generation charges are more or less a function of the cost of fuel inputs (e.g., natural gas, oil, gas) the utility wire charges are set via regulation and are static, but somewhat arbitrary. Unless a customer can disconnect completely from the grid they must pay monthly customer charges and demand (kW) charges.

Energy charges can be avoided (in part) by the installation of a wind turbine . Energy charges constitute a very large share of MCC's electric bill. We calculate the yearly savings in energy charges by calculating the annual turbine electricity production on site (kWh/yr) and multiplying it by the energy cost ($/kWh) that would have been paid for the same electricity purchased from the utility or DA provider.

Based on data from the local Air Quality Management District (AQMD) anemometer the wind appears to peak in the afternoon as shown in the chart below. The effects are actually more pronounced than shown below because the power output is proportional to wind speed raised to the third power due to what are called the 'fan laws'. This has an impact on the economics since the energy prices usually vary significantly between On-Peak and Off-Peak. This was not analyzed as part of this project but it will be evaluated as part of a more detailed study. Another factor to consider is the current discussion of real-time pricing in California. It is not possible to quantify this now since specifics are lacking but it may be a factor to consider in long-term projections for your applicable energy rates.



Estimating Turbine Energy Production

We use the manufacturers rated turbine performance then adjust it for:

- Density (elevation)
- Performance Degradation
- Turbine Availability
- Derating for turbulence, wire run losses and other performance influencing factors

Renewable Energy Credits

Renewable energy credits (RECs) offer a new approach for buying green power. Also known as Tradable Renewable Certificates (TRCs), or “green tags”, RECs represent the environmental attributes of a unit (typically one megawatt-hour) of electricity generated from renewable fuels that can be sold separately from the electricity. For producers, selling RECs can generate a revenue stream separate from the production of electricity. For consumers, RECs make it possible to support renewable energy generated from many types of fuels in favorable locations and to separate investments in renewable energy from their electric power purchases, thus avoiding the need to switch power providers.

RECs are transacted in two arenas: voluntary markets and regulatory compliance markets. Voluntary purchasers - companies, government agencies, nonprofit institutions, or households - buy RECs from sources of their choice for purposes such as supporting renewable energy development, meeting corporate environmental performance pledges, or stimulating local economic development. Electric power providers may also buy RECs, combine the credits with conventional electric power, and sell the bundled product as renewable energy.

Regulatory compliance markets exist in states that have adopted renewable portfolio standards (RPSs) requiring that certain percentages of the electricity delivered instate must be generated from renewable energy by specified dates. Electric power providers in these states purchase RECs from providers who meet state RPS criteria to show that they have complied with RPS requirements. Only a few states with RPS requirements have created systems for generating and trading RECs, most notably Texas and Massachusetts, but others are considering similar action. If a national RPS is enacted at some point, it could lead to the creation of a national REC trading program.

In most regulatory compliance markets, especially where states have adopted highly specific RPS requirements, a limited supply of credits exists to meet REC buyers' needs, so prices for these credits tend to be higher than in voluntary markets. In mid- October, according to data from brokerage service Evolution Markets, year 2004 compliance RECs representing one megawatt-hour were selling for about $14 in Texas and for $50 in Massachusetts (where power must come from new renewable facilities to receive credit). In contrast, voluntary RECs generated in a number of locations for years 2003 through 2010 were being offered at prices between $0.75 and $5.00, with a few wind RECs priced at about $15 and one California solar REC offering at $50.

California's recently enacted RPS requires the state's investor owned utilities to increase the renewable portion of their energy mix each year by at least 1% of total retail sales, with a goal of 20% renewable generation by 2017. Governor Schwarzenegger has recently taken steps to accelerate California's renewable portfolio standard to receive 20 percent renewable power by 2010 instead of by 2017.

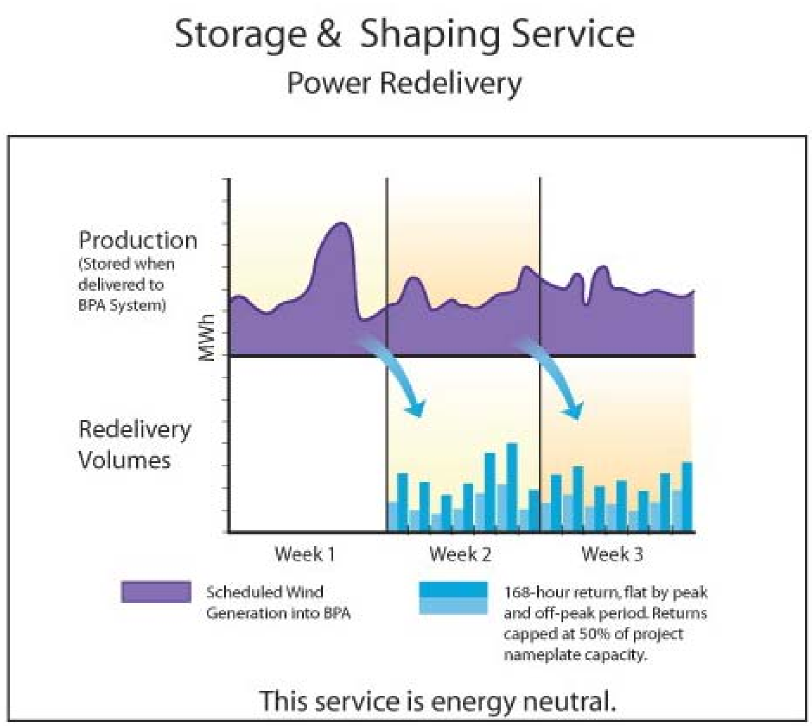
Mandatory compliance with these standards could create a market for RECs similar to Massachusetts. REC sales have not been included in the financial projections.

For more information about REC sales, companies such as Evolution Markets can be consulted: www.evomarkets.com/.

BPA Storage and Shaping Service

BPA has completed an extensive research and development effort to evaluate the costs and opportunities associated with integrating wind energy into the Federal Columbia River Hydroelectric System (FCRPS). This will utilize the flexibility of the hydro system to integrate wind energy in order to serve the needs of entities inside and outside of the BPA Control Area.

The customer will be charged a fee of $4.50/MWh for all scheduled energy that BPA integrates into its system. This fee may be subject to annual escalation depending on the length of the requested contract. For contracts that extend beyond the current rate period, the fee will be escalated at the rate associated with the Gross Domestic Product Implicit Price Deflator, which is the same index used to escalate the Federal Production Tax Credit for wind.



The Storage and Shaping Service has been designed to serve the needs of utilities and other entities outside of the BPA Control Area who have chosen to purchase the output of a new wind resource but do not want to manage the hour-to-hour variability associated with the wind output. To facilitate such an arrangement, BPA's Power Business Line will take the hourly output of new wind projects into the BPA Control Area, integrate and store the energy in the Federal hydro system, and redeliver it a week later in flat peak and off-peak blocks to the power purchasing customer. In order to help reduce transmission costs, returns will be capped at 50 percent of the participant's share of project capacity. The base charge for storage and shaping service is $6.00/MWh, escalated annually at the GDP Implicit Price Deflator.

Storing and shaping wind will allow wind turbines to reduce the demand charges. The cost of this service can be compared to the potential demand savings as part of a more detailed study. The interaction with the Standby Charge will also be evaluated. The viability of using this service for a retail load will have to be evaluated from a legal and regulatory perspective. Additional information on BPA Storage and Shaping Services can be seen in Attachment I.

Sensitivity Analysis

Sensitivity analysis requires picking the most important cost elements of the project and varying those costs over an expected range. A sensitivity analysis was not conducted as part of this study. The factors that are most critical and that are typically included in a sensitivity analysis for customer owned equipment are:

1. Wind Resource (electricity production)
2. Installed Cost
3. Operations and Maintenance Cost
4. Energy Escalation Rate
5. Discount Rate used in Net Present Value Calculation

For a Power Purchase Agreement the relevant variables include:

1. Power Purchase Price ($/kWh)
2. PPA Energy Escalation Rate (percent per year)
3. Wind Resource (electricity production)
4. Discount Rate used in Net Present Value Calculation

Note: More sophisticated sensitivity analyses use a Monte Carlo simulation where the probability of variation of each cost driver is determined (i.e. normal distribution). The expected range of variation of each item is modeled with a computer simulation program to see the expected range of variation in the bottom line (NPV, IRR, payback, etc). This is calculated for all variables simultaneously.

Ownership Options

Two primary ownership options can be considered as part of a more detailed study: MCC ownership and third-party ownership (Power Purchase Agreement).

MCC Ownership

In the case of MCC ownership it will be assumed that either:

- The turbine is purchased by MCC and a project manager coordinates the subcontractor and turbine manufacturer efforts
- A general contractor of MCC's choosing purchases the turbine and manages and pays the subcontractors in a turnkey arrangement. Ownership transfers to MCC after electrical installation.

The financial benefits of a wind turbine as described above would be a combination of avoided utility costs and Renewable Energy Credit (REC) sales revenue. REC sales are not included in the financial projections.

Third-Party Ownership – Power Purchase Agreement (PPA)

Under third-party ownership it is assumed that MCC procures electricity generated from the wind turbine(s) at a savings as compared to current and anticipated future retail rates. If a third-party owned and operated the wind turbine, it is assumed that MCC would purchase all of the electricity produced. Electricity would be sold at an agreed upon annual energy rate ($/kWh) and annual escalation rate (%). The rate would be independent of SCE and/or DA rate changes. The rate should also be independent of the time of day that the electricity is generated.

MCC and a third-party owner can benefit from the PTC (1.9 ¢/kWh for 10 years) if the energy is sold between unrelated parties. The PTC has expired and been reauthorized multiple times. Currently the PTC is set to expire on December 31, 2007.

State Incentives

Pursuant to California Assembly Bill 970, the California Public Utilities Commission (CPUC) approved the Self-Generation Incentive Program (SGIP) on March 27, 2001. SGIP provides financial incentives for business and residential customers who install up to 5.0 MW of clean distributed generation equipment onsite.

Qualifying self-generation equipment must be certified to operate in parallel with the electrical grid and meet other criteria established by the CPUC. The SGIP program currently runs through December 31, 2007.

For wind turbine projects, the incentive offered is $1.50/watt up to a maximum of 1 MW which equates to $1.5 million.

Project Financials

	John Bull Flat	Cleghorn	Specialty Minerals	Specialty Minerals
Assumptions				
Nameplate Capacity (MW)	25	25	4.5	1
Mean Wind Speed (meters/second)	7.25	8.75	6	6
Weibull Distribution Factor	2	2	2	2
Elevation (meters)	2,500	1,600	1,400	1,400
Energy Cost ($/kWh)	$0.0565	$0.0565	$0.0680	$0.0830
Capacity Charge ($/MW-Year)	$13,800	$13,800	$0	$0
O&M Cost ($/kWh)	$0.010	$0.010	$0.012	$0.014
Derating for I^2R Losses and Turbulence (%)	10%	10%	10%	10%
Turbine Availability (%)	99%	99%	97%	95%
Degradation (%)	2%	2%	2%	2%
Total Deration (%)	87.3%	87.3%	85.6%	83.8%
Calculation of Installed Cost (NPV Basis)				
Distance From Turbnies to Interconnection	4	25	2	2
Electrical Interconection Cost ($/Mile)	$80,000	$100,000	$80,000	$80,000
Electrical Interconnection Cost ($)	$320,000	$2,500,000	$160,000	$160,000
Wind Turbine Cost ($/MW)	$1,200,000	$1,200,000	$1,250,000	$1,400,000
Balance of Plant ($/MW)	$200,000	$200,000	$250,000	$300,000
Development, Legal, Finance etc ($/MW)	$100,000	$100,000	$125,000	$150,000
Developer Profit ($/MW)	$100,000	$100,000	$150,000	$200,000
Total Installed Cost ($/MW)	$1,600,000	$1,600,000	$1,775,000	$2,050,000
Total Installed Cost ($)	$40,320,000	$42,500,000	$8,147,500	$2,210,000
Self Generation Incentive Program ($)	$0	$0	$1,500,000	$1,500,000
Net Installed Cost ($)	$40,320,000	$42,500,000	$6,647,500	$710,000
NPV of Federal Tax Benefits (% of Inst. Cost)	55%	55%	40%	25%
Net Present Value Installed Cost ($)	**$18,144,000**	**$19,125,000**	**$3,988,500**	**$532,500**
Calculation of Annual Savings				
Energy Production (kWh/yr)	61,872,277	84,991,423	8,017,204	1,765,068
Energy Cost Savings ($/yr)	$3,495,784	$4,802,015	$545,170	$146,501
Less Capacity Cost ($/yr)	-$345,000	-$345,000	$0	$0
Energy Cost Savings ($/yr)	$3,150,784	$4,457,015	$545,170	$146,501
Less O&M Cost ($/yr)	-$618,723	-$849,914	-$96,206	-$24,711
Renewable Energy Credit Sales	$0	$0	$0	$0
Annual Cash Flow ($/yr)	**$2,532,061**	**$3,607,101**	**$448,963**	**$121,790**
Payback	**7.2**	**5.3**	**8.9**	**4.4**

Next Steps

Action	Description
Feasibility Study Review	Review proposal with MCC including proposed locations, assumptions on avoided energy costs and financing options. Review DA contract.
Discuss Options for a More Detailed Analysis	Discuss a combined project with Specialty Minerals Inc. including sharing the cost of a Meteorological Tower (MET). A MET will cost about $20,000 including installation, monitoring and reporting.
San Bernardino National Forest Service (NFS)	Start discussions with NFS with goal being to agree on the price for an option on the land so that a MET can be installed.
Transmission Right –of-Way for Cleghorn Ridge	Identify owner of Railroad and start discussions on transmission right-of-way.
Electrical Interconnection of Turbine in Specialty Minerals Inc. Property	Confirm that SCE will or will not accept and Interconnection Application. The SCE Interconnection Manager is Jerry Torribio (626-302-9669). Consider MCC and/or CLECA support of Senate Bill SB 1727
Standby Charge (Schedule S)	Consider MCC and/or CLECA support for requesting an exemption from new Standby Charges (Schedule S) based on the fact that wind turbines (being intermittent) do not reduce a customer's monthly demand charge. An interruptible rate should also be made available within Schedule S for customers who request standby service for their interruptible rate.

List of Attachments

- **Attachment A:** GE 1.5 MW Brochure
- **Attachment B:** Fuhrländer FL1000B Data Sheet
- **Attachment C:** Executive Summary - SB 1727 (Kehoe)
- **Attachment D:** Letter to NFS
- **Attachment E:** SCE Standby Schedule S
- **Attachment F:** SCE DA-CRS
- **Attachment G:** Meteorologist Resume
- **Attachment H:** Long-Term O&M Costs of Wind Turbines
- **Attachment I:** BPA Storage and Shaping Services
- **Attachment J:** Grove Crane Brochure
- **Attachment K:** SGIP Handbook- What's new in 2006
- **Attachment L:** Scott Debenham Curriculum Vitae
- **Attachment M:** Debenham Energy, LLC Brochure

GE Energy

1.5MW Series Wind Turbine

ecomagination℠
a GE commitment

imagination at work

Cefn Croes, Wales
39 x 1.5se
total capacity: 58.5 MW

Gatun, Spain
33 x 1.5sl
total capacity: 49.5 MW

When it comes to "megawatt-plus" technology, our proven 1.5 MW wind turbine continues to raise the bar. From ongoing technology investments in reliability and dependability, to more cost effective and versatile configurations, it need not rest on its past successes. Today, with over 3,300 units in operation worldwide, the 1.5 MW continues to be one of the world's most widely used wind turbines in its class.

Active yaw and pitch regulated with power/torque control capability and an asynchronous generator, the 1.5 MW machine utilizes a bed-plate drive train design where all nacelle components are joined on a common structure, providing exceptional durability. The generator and gearbox are supported by elastomeric elements to minimize noise emissions.

Haute Lys, France
25 x 1.5s
total capacity: 37.5 MW

The 1.5 MW wind turbine also employs a variety of features inherent in GE's full line of wind turbines which range from 1.5 to 3.6 MW, for both on and offshore use.

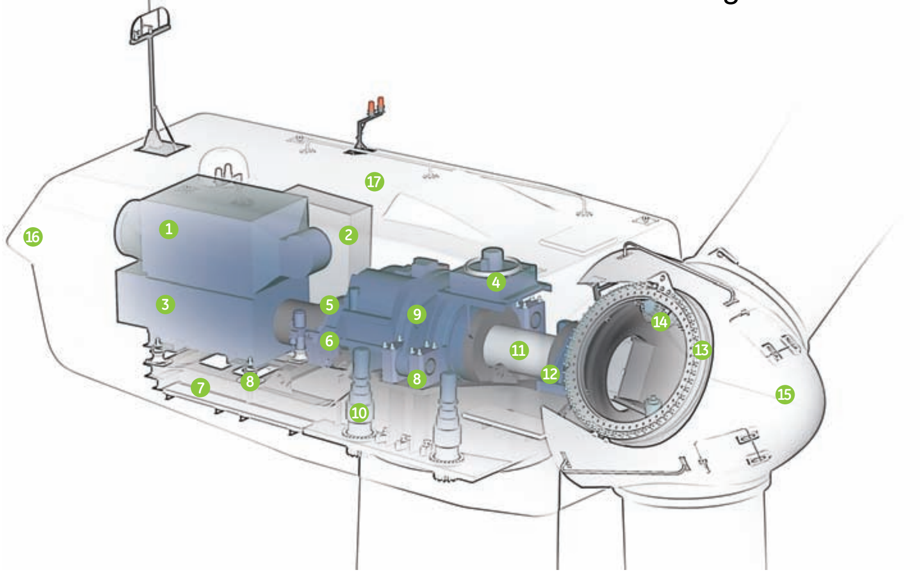
GE's Fleet-Wide Features and Benefits

Feature	Benefit
Variable Hub heights & rotor diameters	Provides versatility/adaptability to a wide variety of project sites
Variable Speed Control and Advanced Blade Pitch	Enables aerodynamic efficiency and reduces loads to the drive train, thereby reducing maintenance cost and providing longer turbine life
WindVAR (optional) (Wind-Volt-Amp-Reactive "WindVAR")	GE's unique electronics provide transmission efficiencies and enable harmonious function within the local grid
Low Voltage Ride-Thru (optional)	Allows wind turbines to stay on line generating power, even during grid disturbances.

New Mexico Wind Energy Center, USA
136 x 1.5s
total capacity: 204 MW

As one of the world's leading wind turbine suppliers, GE Energy's current product portfolio includes wind turbines with rated capacities ranging from 1,500 to 3,600 kilowatts and support services extending from development assistance to operation and maintenance. We currently design and produce wind turbines in Germany, Spain and the U.S.

Our facilities are registered to ISO 9001:2000. Our Quality Management System, which incorporates our rigorous Six Sigma methodologies, provides our customers with quality assurance backed by the strength of GE. We know that wind power will be an integral part of the world energy mix in this century and we are committed to helping our customers design and implement energy solutions for their unique energy needs. Every relationship we pursue bears our uncompromising commitment to quality and innovation.

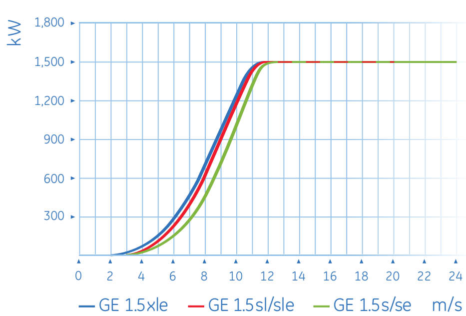


1. Heat exchanger
2. Control panel
3. Generator
4. Oil cooler
5. Coupling
6. Hydraulic parking brake
7. Main frame
8. Impact noise insulation
9. Gearbox
10. Yaw drive
11. Rotor shaft
12. Bearing housing
13. Rotor hub
14. Pitch drive
15. Nose cone
16. Ventilation
17. Nacelle

Technical Data

Technical Data	1.5s	1.5se	1.5sl (50Hz only)	1.5sle	1.5xle
Operating data					
• Rated capacity:	1,500 kW	1,500 kW	1,500 kW	1,500 kW	1,500 kW
• Cut-in wind speed:	4 m/s	4 m/s	3,5 m/s	3,5 m/s	3,5 m/s
• Cut-out wind speed (10 min. avg.):	25 m/s	25 m/s	20 m/s	25 m/s	20 m/s
• Rated wind speed:	13 m/s	13 m/s	14 m/s	14 m/s	12,5 m/s
• Wind Class - IEC:	IIa	Ib	–	IIa (V_{e50} = 55 m/s)	IIIb (V_{ave}= 8.0 m/s)
• Wind Class - DIBt WZ:	II/III	–	II	–	II
Rotor					
• Number of rotor blades:	3	3	3	3	3
• Rotor diameter:	70,5 m	70,5 m	77 m	77 m	82,5 m
• Swept area:	3904 m²	3904 m²	4657 m²	4657 m²	5346 m²
• Rotor speed (variable):	12,0 – 22,2 rpm	12,0 – 22,2 rpm	11,0 – 20,4 rpm	11,0 – 20,4 rpm	10,1 – 18,7 rpm
Tower					
• Hub heights - IEC:	64,7 m	54,7/64,7 m	–	61,4/64,7/80 m	58,7/80/100 m
• Hub heights - DIBt:	64,7 m	–	61,4 to 100 m	61,4/64,7/80/85/100 m	58,7/80/100 m
Power control	Active blade pitch control	Active blade pitch control	Active blade pitch control	Active blade pitch control	Active blade pitch control

Power Curve



Gearbox
- Three step planetary spur gear system

Generator
- Doubly fed, three-phase induction (asynchronous)

Converter
- Pulse-width modulated IGBT frequency converter

Braking system (fail-safe)
- Electromechanical pitch control for each blade (3 self-contained systems)
- Hydraulic parking brake

Yaw system
- Electromechanical driven with wind direction sensor and automatic cable unwind

Control system
- PLC (Programmable logic controller) with remote control and monitoring system

Noise reduction
- Impact noise insulation of the gearbox and generator
- Sound reduced gearbox
- Noise reduced nacelle
- Rotor blades with minimized noise level

Lightning protection system
- Lightning receptors installed along blades
- Surge protection in electrical components

Tower design
- Multi-coated, conical tubular steel tower with safety ladder to the nacelle
- Load lifting system, load-bearing capacity over 200 kg

Operating limits (outside temperature)
- cold weather extreme: -30° C to +40° C / -40° C to +50° C survival without operation
- standard: -15° C to +40° C / -20° C to +50° C survival

www.gewindenergy.com

Subject to technical alterations, errors and omissions. *only for WZII

UTILITY SIZED WIND TURBINE
for distributed generation or wind farm applications

Fuhrländer

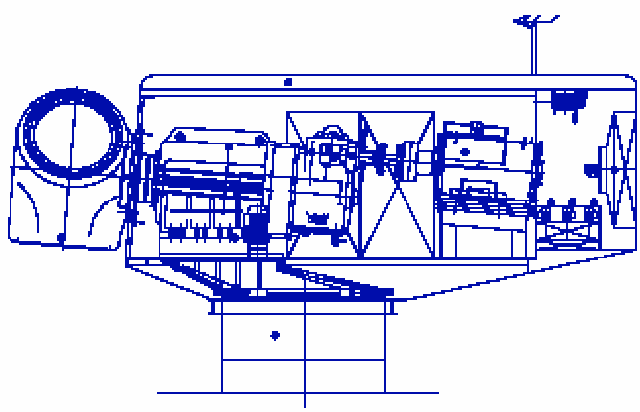
FL 1000 B

WIND TURBINE	FL 1000-B	
ROTOR		
diameter	60 m	
Area	2,827 m^2	
number of blades	3	
speed	15 / 22 rpm	
power regulation	stall	
GEAR BOX		
type	combined	
stages	3	
ratio	1 : 80	
GENERATOR		
type	asynchronous, 3 phase, water cooled	
speed	1200 and 1800 rpm	
voltage	690 V AC	
POWER CHARACTER		
rated output	1,000 kW	
cut in	3.5 m/s	
rated output at	11.5 m/s	
cut out	20 m/s	
survival wind speed	55 m/s	
TOWER		
hub height	70m / 85m	60m / 70m
type	Tubular	Lattice
WEIGHT		
rotor	20,500 kg	
nacelle	40.500 kg	
FL 1000 tower	70 m: 95,000 kg	85 m: 120,000 kg
CONTROL SYSTEMS		
speed regulation	grid connected	
yawing control	3 yaw motors	
main brake	disk brake (low speed shaft)	
second brake system	disk brake (high speed shaft)	
monitoring	remote data and control	
SOUND		
noise level	99.5 dB(A) at hub, 45 dB(A) at 100m	
Tonality	none	
Pulsation	none	

Specifications are subject to change as improvements are incorporated.

The **Fuhrländer 1000 B** is a new wind turbine with a simplified rotor / drive train system (fixed pitch blades without tip brakes) designed for sites with light to moderate wind resources. These machines draw on their integrated main bearing / gearbox and constant speed rotor, to provide exceptional durability and reliability. The water cooled, dual speed asynchronous generator provides efficient power production at all wind speeds. An advanced SCADA controller provides remote monitoring and control. Especially suited for large scale wind power projects in light to moderate wind areas, the FL 1000 B wind turbine is the investor's choice for trouble free, long term power production.

Lorax Energy Systems, LLC is the North American Distributor for **Fuhrländer** Wind Turbines. For more information on these elegant machines, contact our sales office.



Lorax Energy Systems, LLC - North American Distributor for Fuhrländer Wind Turbines
Sales Office: 4 Airport Road, Block Island, RI 02807 Phone: (401) 466-2883 Fax: (401) 466-2909
Corporate Office: 1659 State St, Webster, NY 14580 Phone: (585) 265-6690 Fax: (585) 265-1306
Email: sales@lorax-energy.com Web: www.lorax-energy.com
Site Evaluation ● Wind Turbine Sales ● Installation ● Monitoring ● Maintenance

SB 1727 (Kehoe) Public Utilities: electrical corporations.

Summary: Under existing law, the Public Utilities Commission has regulatory authority over public utilities, including electrical corporations. An electrical corporation is defined as including every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others. This bill would additionally create an exception from the definition of an "electrical corporation," where electricity is generated on private real property and privately distributed across a highway, as defined, to an immediately adjacent private real property owned or otherwise controlled by the corporation or person, solely for its own use or the use of its tenants and not for sale or transmission to others. The bill would make conforming changes to specific exceptions for certain persons or corporations using cogeneration, landfill gas technology, and digester gas technology for the generation of electricity.

IEP Position:

Status: 03/09/2006-To Com. on E.,U. & C.
Current Text: Introduced 02/24/2006
Current Location: 03/09/2006-S E. U., & C.

Debenham Energy, LLC

Wind Energy Development and Consulting
11317 Valle Vista, Lakeside, CA 92040 Ph: 619-334-9541 E-mail: scott@debenhamenergy.com

Veronica Magnuson
National Forest Service
PO Box 350
Skyforest. CA 92385

March 17, 2005

Dear Ms. Magnuson,

Enclosed is information on 2 possible locations for wind turbines on National Forest Service land. The specific locations will depend on many factors that are best discussed via phone calls and eventually face to face meetings.

I would like to use this letter to start a dialogue on this potential project. From a wind developers perspective it is important to focus on the areas with the best wind and road access. Tradeoffs on the optimal wind location can be made to incorporate possible habitat impacts, environmental issues and esthetic concerns as long as the project economics are likely to be viable.

I have selected 2 general areas that I am referring to as

1. Cleghorn Ridge
2. Greenlead Mine / Harvey K Mine / John Bull Flat Area

The optimal location on Cleghorn Ridge from a wind resource perspective is easily identifiable. It is on top of the ridge. The second area near the mines and John Bull Flat will require some further meteorological analysis to identify the optimal location(s). I have identified a relatively large area so that you can evaluate the areas with the lowest impact. I can then refine my meteorological analysis. I look at this as an iterative approach with this being the starting point.

I look forward to working with you. Do not hesitate to call if you have any questions.

Regards,

Scott Debenham

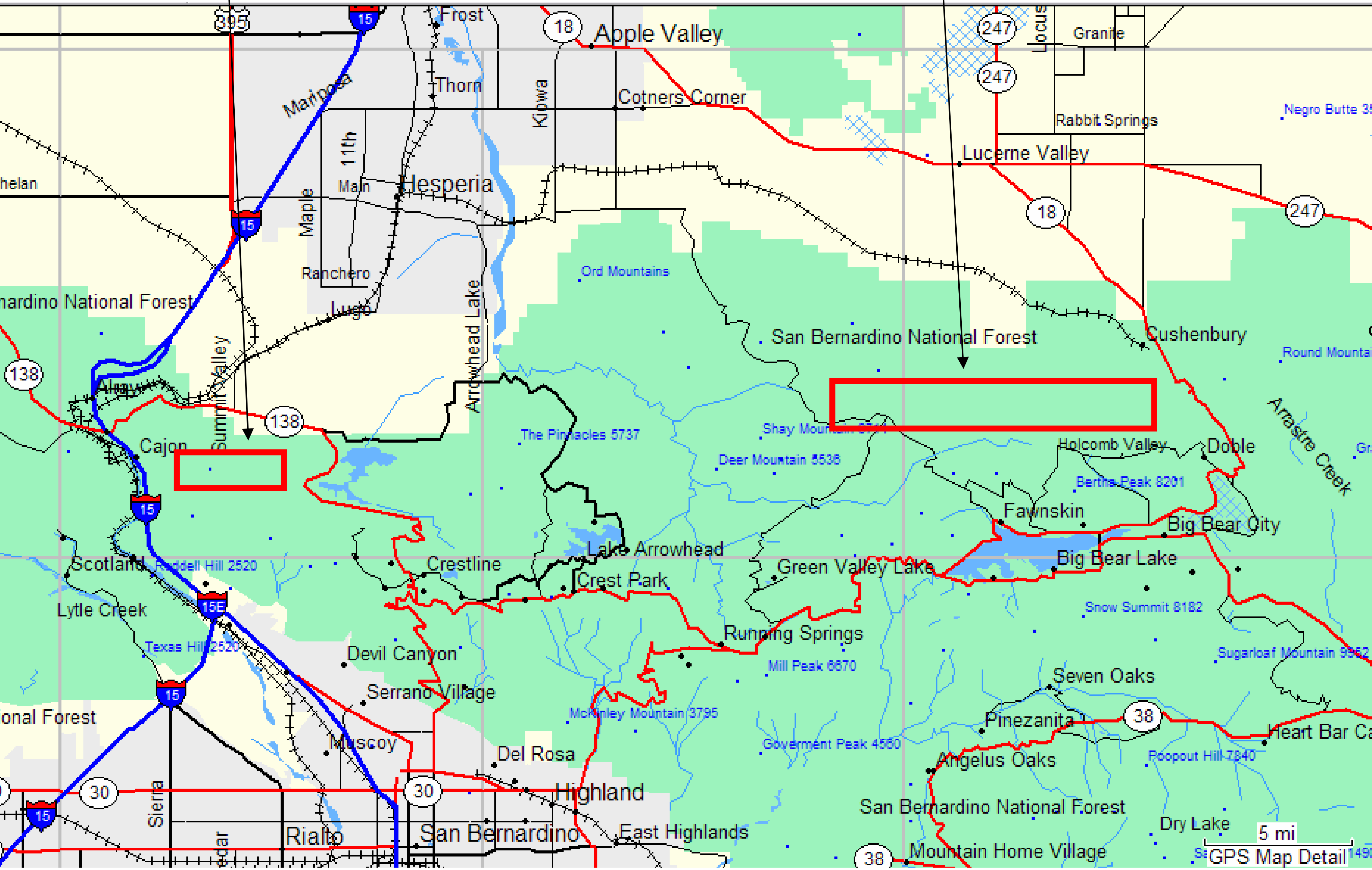
Scott Debenham
Debenham Energy LLC
www.debenhamenergy.com

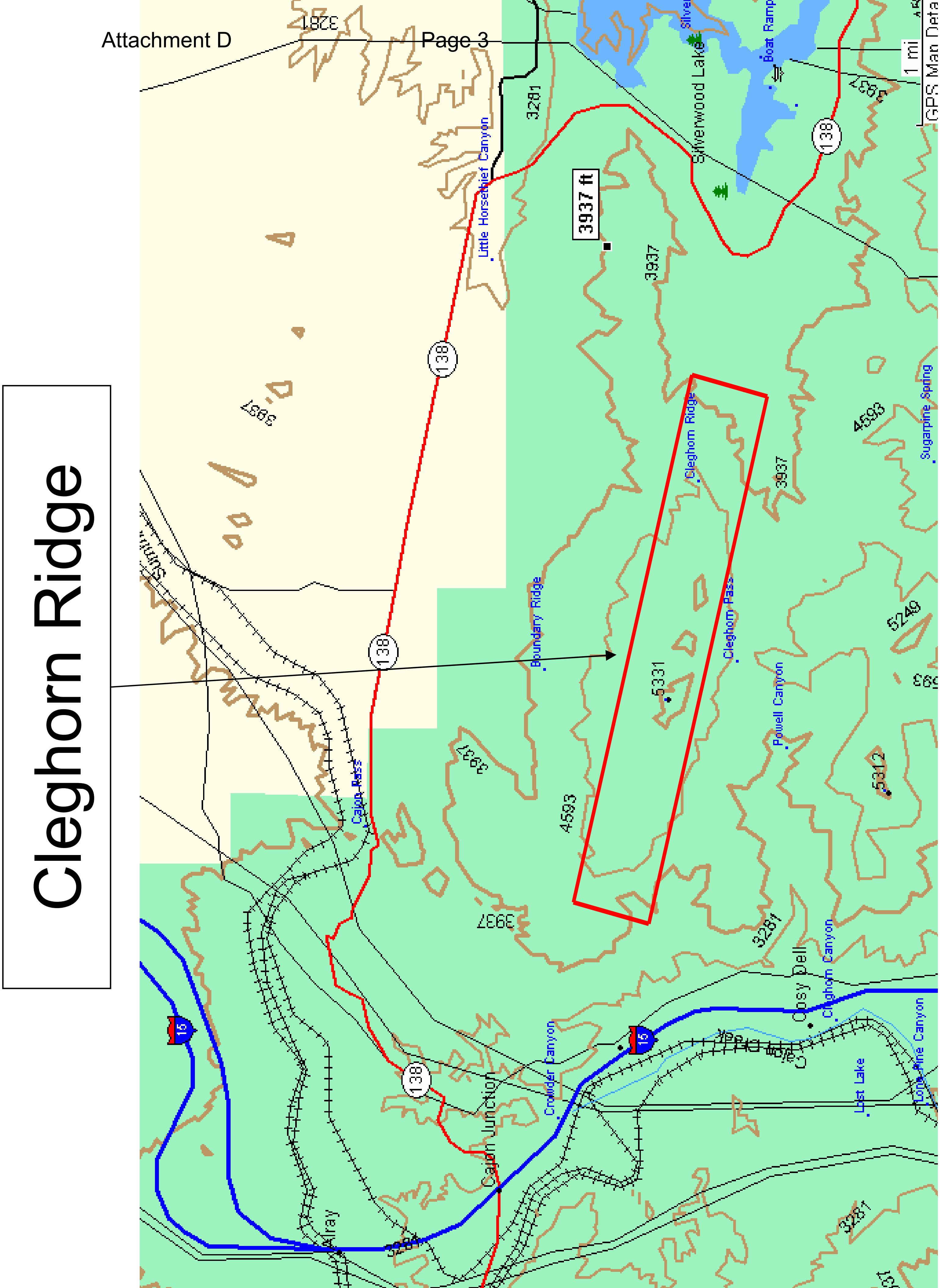
Attachment D

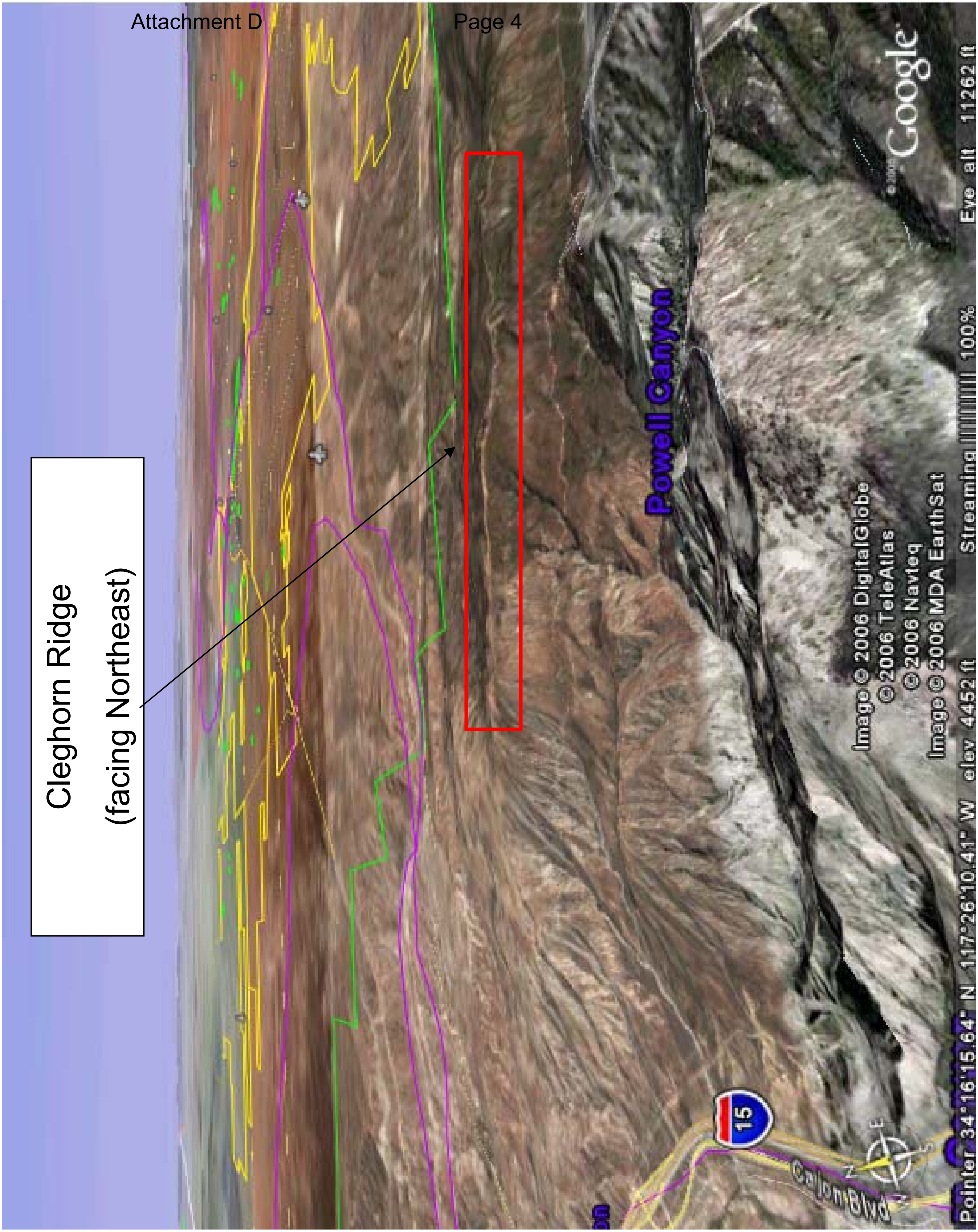
Page 2

Cleghorn Ridge

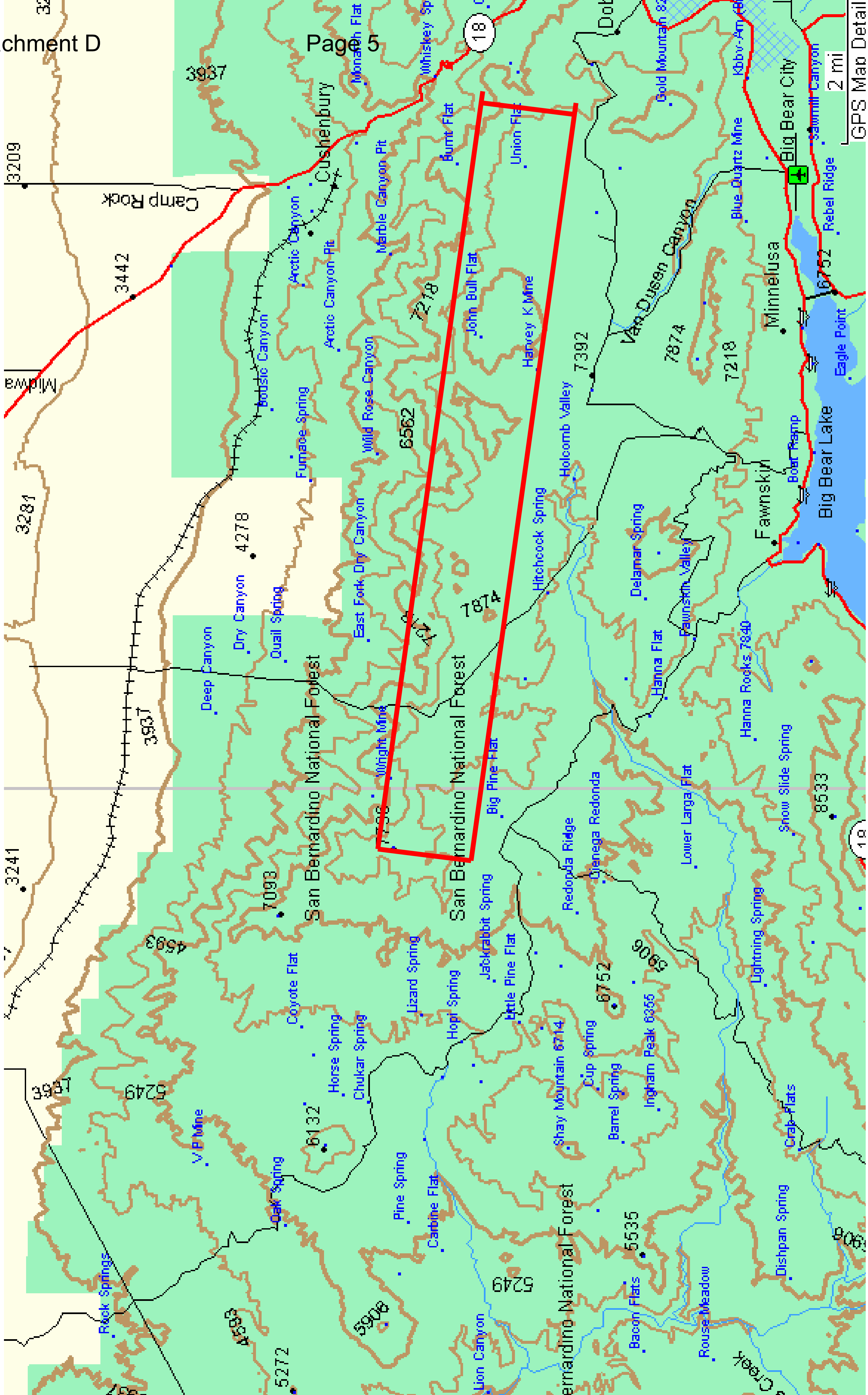
Greenlead Mine / Harvey K Mine / John Bull Flat



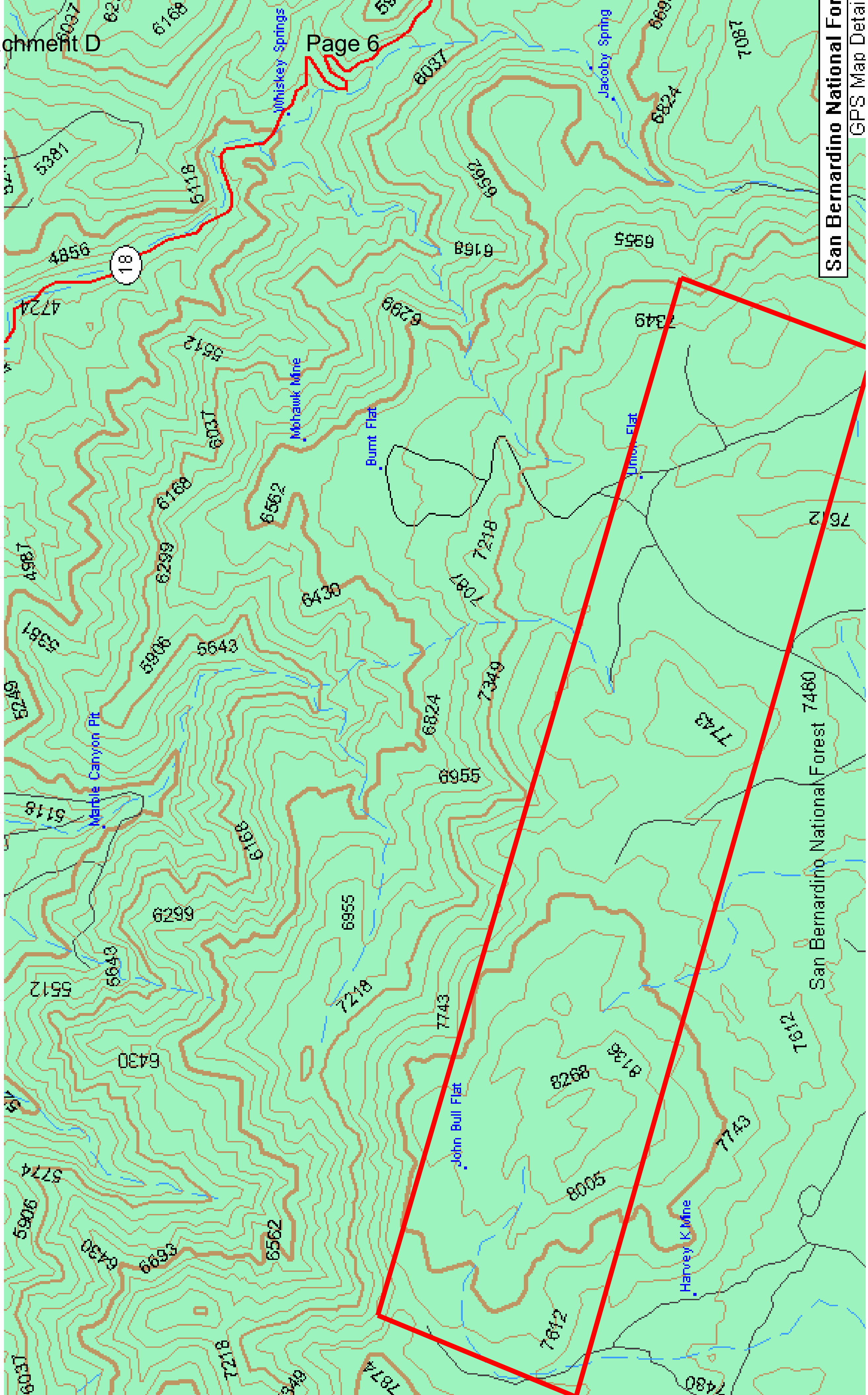

Cleghorn Ridge
3937 ft
Silverwood Lake
Boat Ramp
1 mi
Little Horsethief Canyon
138
Boundary Ridge
Cleghorn Ridge
Cleghorn Pass
Powell Canyon
Sugarpine Spring
Cajon Pass
Cajon Junction
Crowder Canyon
Cosy Dell
Cleghorn Canyon
Lost Lake
Lone Pine Canyon
Alray
15
3281
3937
4593
5331
5249
5312


Cleghorn Ridge
(facing Northeast)
Powell Canyon
15
Cajon Blvd
Image © 2006 DigitalGlobe
© 2006 TeleAtlas
© 2006 Navteq
Image © 2006 MDA EarthSat
© 2005 Google
Pointer 34°16'15.64" N 117°26'10.41" W elev 4452 ft Streaming 100% Eye alt 11262 ft

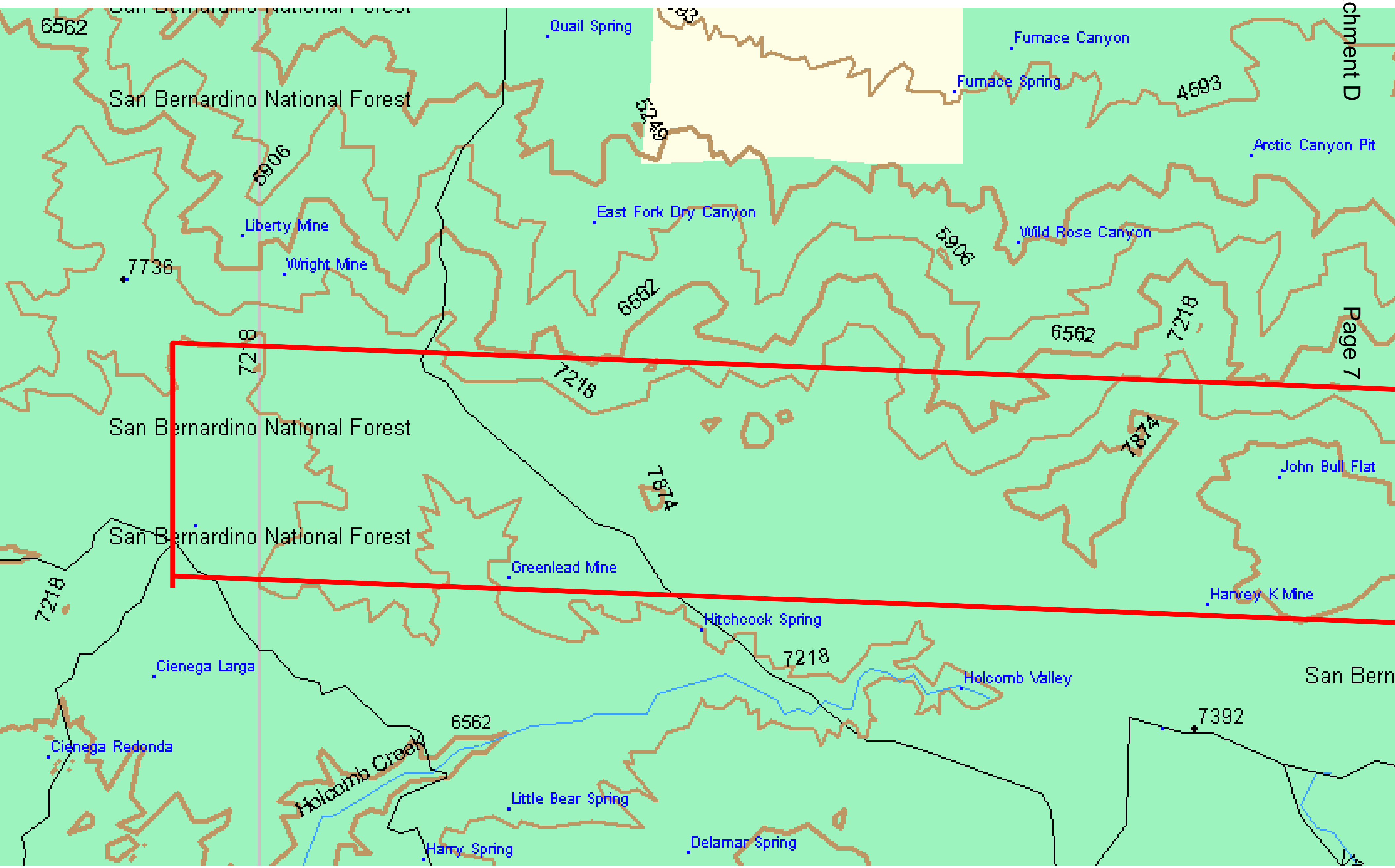
Greenlead Mine / Harvey K Mine / John Bull Flat

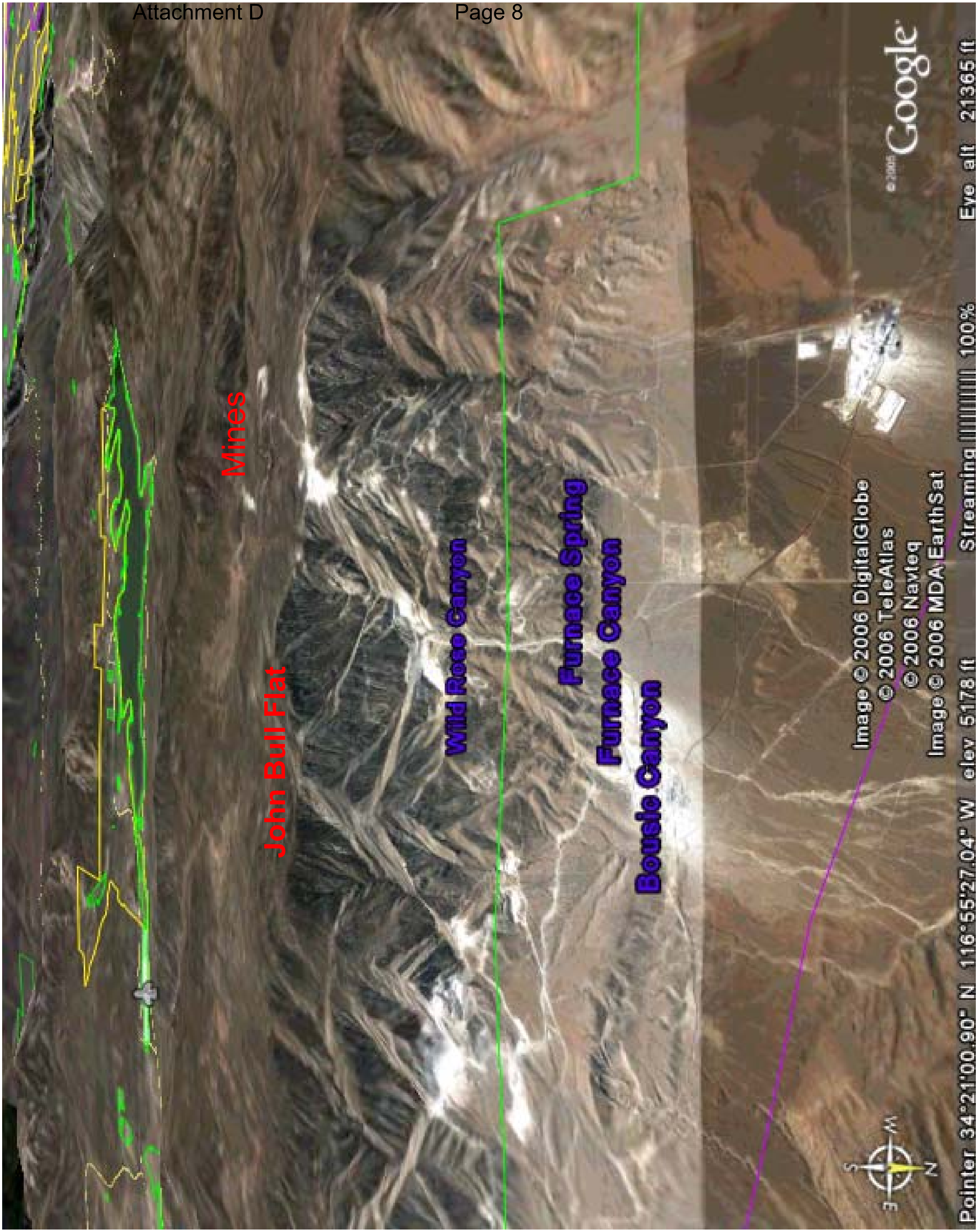


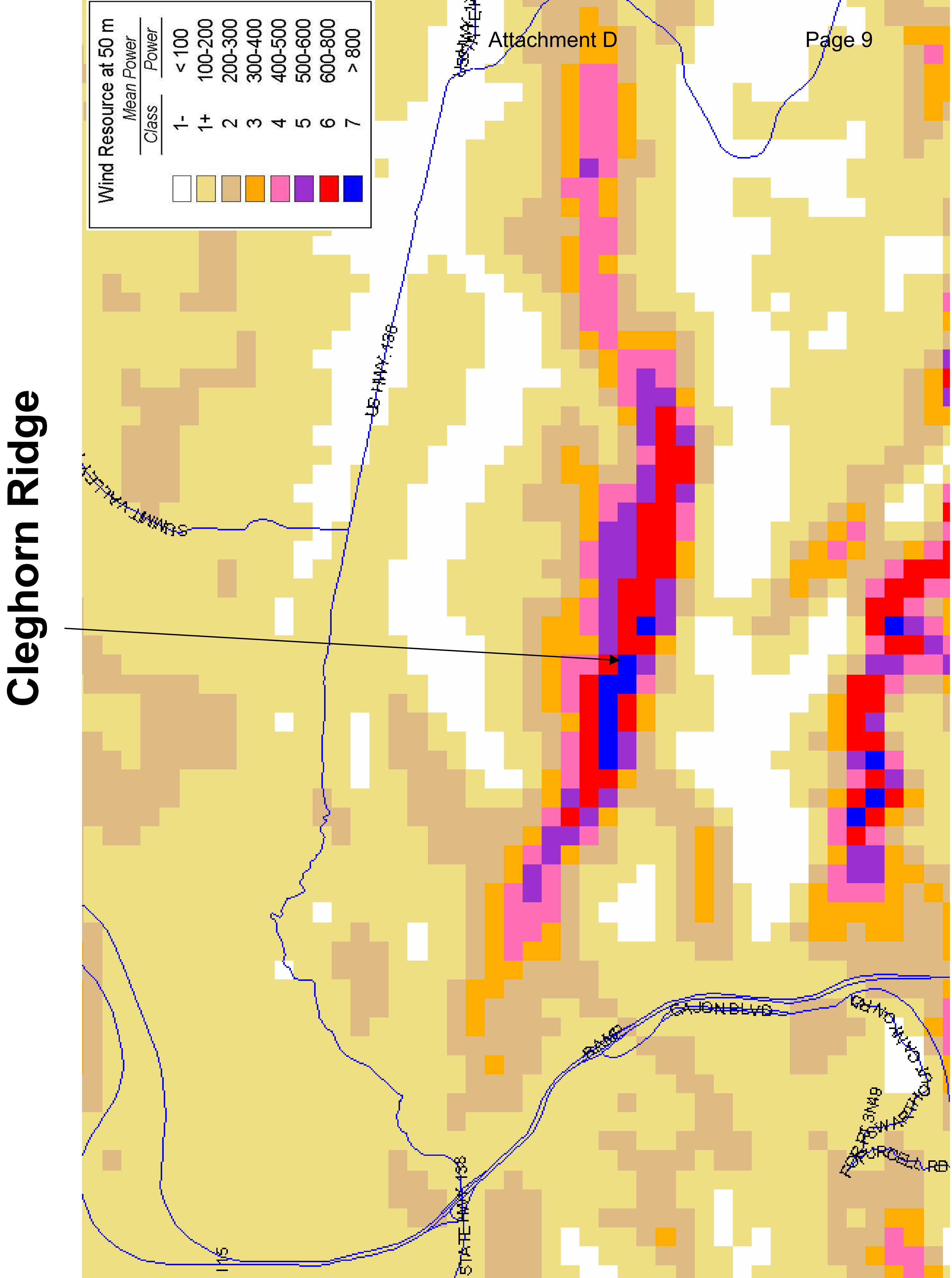
Greenlead Mine / Harvey K Mine / John Bull Flat



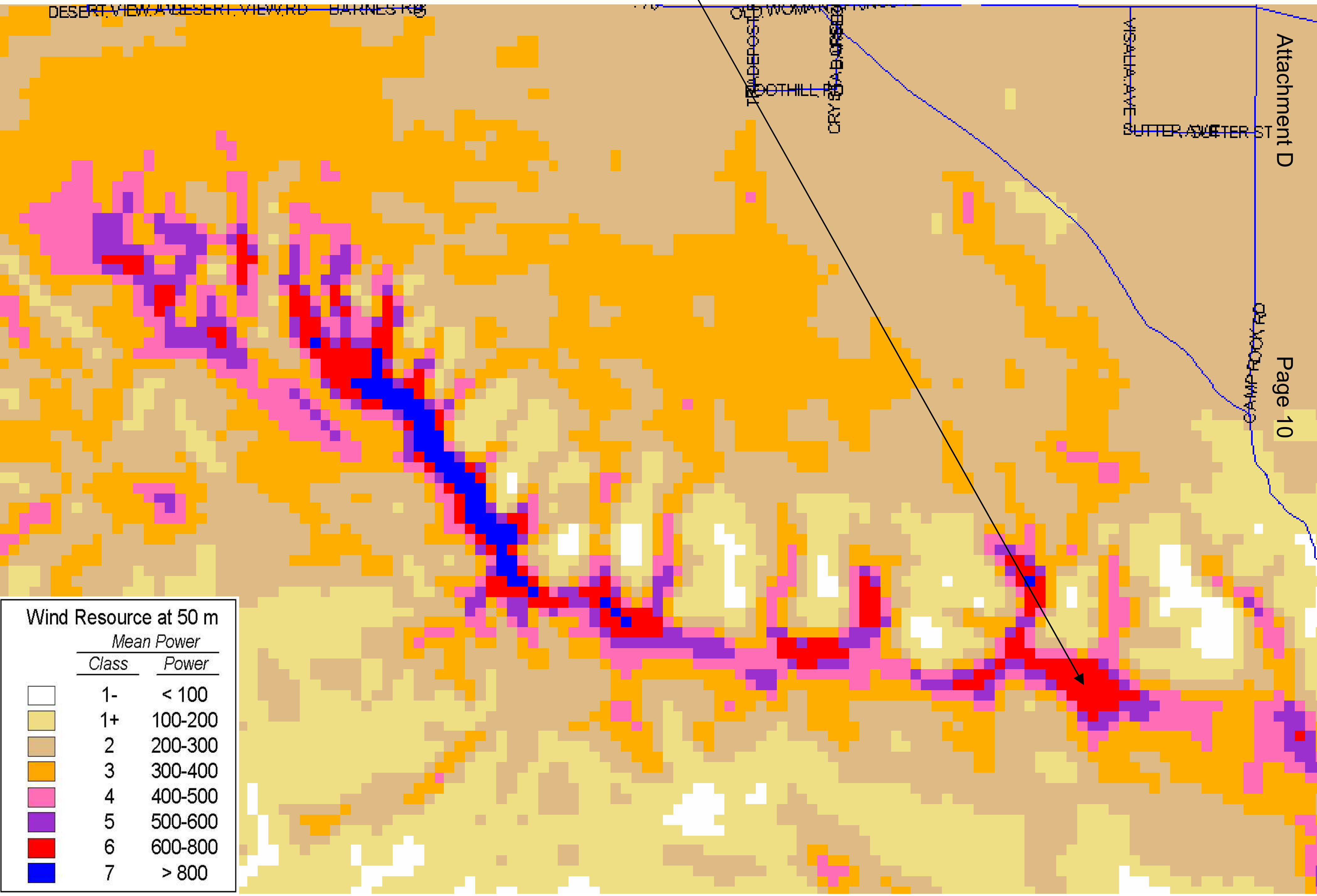
Greenlead Mine / Harvey K Mine / John Bull Flat




Mines
John Bull Flat
Wild Rose Canyon
Furnace Spring
Furnace Canyon
Bousic Canyon
Image © 2006 DigitalGlobe
© 2006 TeleAtlas
© 2006 Navteq
Image © 2006 MDA EarthSat
Google
Pointer 34°21'00.90" N 116°55'27.04" W elev 5178 ft
Streaming 100%
Eye alt 21365 ft


Cleghorn Ridge
Wind Resource at 50 m
Class
Mean Power
Power
1- < 100
1+ 100-200
2 200-300
3 300-400
4 400-500
5 500-600
6 600-800
7 > 800
US HWY 138
SUMMIT VALLEY
CAJON BLVD
RAMP
STATE HWY 138
I-15
CAJON CANYON
RD

Greenlead Mine / Harvey K Mine / John Bull Flat



Schedule S Sheet 1
STANDBY

APPLICABILITY

Applicable to customers taking service under a regular service rate schedule and where a part or all of the electrical requirements of the customer can be supplied from a generating facility as defined, interconnected, and operated in accordance with Rule 21, but will be provided electric service from (T) SCE's electrical system during periods of outage of the customer's generating facility. A generating (T) facility may be connected for: (1) parallel operation with the service of SCE; or (2) isolated operation with standby or breakdown service provided by SCE by means of a double throw switch. This (C) Schedule is also applicable to a generating facility interconnected and operated in accordance with SCE's wholesale distribution access tariff (WDAT) or transmission owners (TO) tariff in order to sell power to the grid and receive electric service from SCE at any time for generating facility loads normally served by such facility. (C)

Service provided under this Schedule shall be either Backup Service or Maintenance Service. (N) Backup Service is applicable when customers request SCE to provide service instantaneously during unscheduled outages of the customer's generating facility. Maintenance Service is applicable when customers request SCE to provide service during outages of the customer's generating facility for periods scheduled with and approved by SCE.

Service provided from SCE's electrical system to the customer's load that is not regularly supplied by the customer's generating facility during normal operation of such generating facility is considered Supplemental Service and is billed under the otherwise applicable tariff (OAT). (N)

Customers operating certain types of generating facilities or served under certain tariff schedules shall (T) be exempt from the charges of this Schedule as set forth in the Special Conditions section, below.

Interval Metering capable of recording in 15-minute intervals the service provided from SCE's (T) electrical system is required for service under this Schedule. The interval metering shall be provided in accordance with SCE's tariffs at the customer's expense. Service under this Schedule is subject to (N) meter availability. When net generation output (NGO) metering is installed on the customer's generating facility and is used to determine the charges under this Schedule and the OAT, such metering shall be capable of recording the output of the generating facility in 15-minute intervals. NGO interval metering shall be provided at the customer's expense and in accordance with the provisions and requirements of the applicable SCE tariffs.

TERRITORY (N)

Within the entire territory served.

(Continued)

Southern California Edison — Revised — Cal. PUC Sheet No. 39822-E
Rosemead, California — Cancelling — Revised — Cal. PUC Sheet No. 39577-E

Schedule S
STANDBY

Sheet 2

(Continued)

RATES

Except as provided under this Schedule, the charges, terms and conditions of the customer's OAT shall apply.

Charges for Backup Service and Maintenance Service are as follows:

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG***	DWR
Capacity Reservation Charge - $/kW of Standby Demand/Meter/Month*									
Maximum Demand of 500 kW or less	0.30	4.02					4.32		
Maximum Demand Greater than 500 kW									
Below 2 kV	0.30	4.02					4.32		
From 2 kV to 50 kV	0.23	3.93					4.16		
Above 50 kV but Below 220 kV	0.17	0.98					1.15		
At 220 kV	0.17	0.00					0.17		
Customer Charge - $/Meter/Month **									
Maximum Demand of 500 kW or less		63.71 (R)					63.71 (R)		
Maximum Demand Greater than 500 kW									
Below 2 kV		287.88 (R)					287.88 (R)		
From 2 kV to 50 kV		288.22 (R)					288.22 (R)		
Above 50 kV but Below 220 kV		336.86 (R)					336.86 (R)		
At 220 kV		336.86 (R)					336.86 (R)		
Backup Service									
Demand Charge - $/kW of Billing Demand/Meter/Month									
Maximum Demand of 500 kW or less									
Facilities Related	0.00	0.00					0.00	4.20 (I)	
Summer Time Related		0.00					0.00	10.21 (I)	
Voltage Discount, Facilities Related Demand - $/kW									
From 2kV to 50 kV		0.00					0.00	(0.04) (I)	
Above 50 kV, Less 220 kV		0.00					0.00	(0.10) (I)	
220 kV and above		0.00					0.00	(0.10) (I)	
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV		0.00					0.00	(0.10) (I)	
Above 50 kV, Less 220 kV		0.00					0.00	(0.26) (I)	
220 kV and above		0.00					0.00	(0.26) (I)	
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV		0.00520					0.00520	(0.00139) (I)	
Above 50 kV, Less 220 kV		(0.00586)					(0.00586)	(0.00299) (I)	
220 kV and above		(0.01067)					(0.01067)	(0.00304) (I)	
Maximum Demand of Greater than 500 kW									
Facilities Related									
Below 2 KV	0.00	0.00					0.00	2.27 (I)	
From 2 kV to 50 kV	0.00	0.00					0.00	2.41 (I)	
Above 50 kV but Below 220 kV	0.00	0.00					0.00	0.00	
At 220 kV	0.00	0.00					0.00	0.00	
Summer Time Related									
Below 2 KV									
On-Peak		0.00					0.00	13.64 (I)	
Mid-Peak		0.00					0.00	2.52 (I)	
Off-Peak		N/A					N/A	N/A	
From 2 kV to 50kV									
On-Peak		0.00					0.00	14.94 (I)	
Mid-Peak		0.00					0.00	2.51 (I)	
Off-Peak		N/A					N/A	N/A	
Above 50 kV but Below 220 kV									
On-Peak		0.00					0.00	12.35 (I)	
Mid-Peak		0.00					0.00	2.00 (I)	
Off-Peak		N/A					N/A	N/A	
At 220 kV									
On-Peak		0.00					0.00	12.22 (I)	
Mid-Peak		0.00					0.00	1.98 (I)	
Off-Peak		N/A					N/A	N/A	

(Continued)

Southern California Edison Revised Cal. PUC Sheet No. 39823-E
Rosemead, California Cancelling Original Cal. PUC Sheet No. 39578-E

Schedule S Sheet 3
STANDBY

(Continued)

RATES (Continued)

Delivery Service							Gen[8]	
Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG***	DWR

* The Capacity Reservation Charge is based on the kW of Standby Demand. The customer shall designate the kW level of Standby Demand in a generation interconnection agreement or the Contract for Electric Service. Customers that sign and comply with the Customer Physical Assurance Agreement will not be subject to the Capacity Reservation Charge and will pay the charges for Maintenance Service when service is provided during an outage of the customer's generating facility that is scheduled with and approved by SCE.

** The Basic/Customer Charge of the OAT for the Domestic Service/Small Commercial Customer is billed on a $/Day basis rather than on the $/Month basis as provided under this Schedule; therefore, the Basic/Customer Charge of such customer's OAT shall apply for the billing period rather than the Customer Charge shown above.

*** The ongoing Competition Transition Charge (CTC) of $0.00028 for voltages below 2kV, $0.00026 for voltages from 2kV-50kV, and $0.00021 for voltages above 50 kV is recovered in the URG component of Generation.

1 Trans = Transmission is FERC approved.
2 Distrbtn = Distribution
3 NDC = Nuclear Decommissioning Charge
4 PPPC = Public Purpose Programs Charge (includes California Alternate Rate for Energy Surcharge where applicable.)
5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10=063, D.02-02-051, and D.02-12-082.
7 Total = Total Delivery Service rates that are applicable to both Bundled Service, Direct Access (DA) and Community Choice Aggregation (CCA) customers, except DA and CCA customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
8 Gen = Generation which is composed of a Utility Retained Generation (URG) rate component and a Department of Water Resources (DWR) rate component. The Gen rates are applicable only to Bundled Service Customers. Bundled Service Customers may elect to have the URG portion of the Gen charges calculated using the rates for URG shown above or using hourly $/kWh rates determined in accordance with the provisions of Schedule PC-TBS. When calculating the Energy Charge using the rates shown above or when the customer elects to be billed using hourly $/kWh rates for URG Gen, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Backup Service (Continued)									
Energy Charge - $/kWh/Meter/Month									
Maximum Demand of 500 kW or less									
Summer Season – On-Peak	0.00149	0.01264 (R)	0.00048 (R)	0.00799 (I)	0.00000	0.00485	0.02745 (I)	0.17857 (I)	0.10369
Mid-Peak	0.00149	0.01264 (R)	0.00048 (R)	0.00799 (I)	0.00000	0.00485	0.02745 (I)	0.07977 (I)	0.10369
Off-Peak	0.00149	0.01264 (R)	0.00048 (R)	0.00799 (I)	0.00000	0.00485	0.02745 (I)	0.01818 (I)	0.10369
Winter Season – On Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00149	0.01264 (R)	0.00048 (R)	0.00799 (I)	0.00000	0.00485	0.02745 (I)	0.11783 (I)	0.10369
Off-Peak	0.00149	0.01264 (R)	0.00048 (R)	0.00799 (I)	0.00000	0.00485	0.02745 (I)	0.02144 (I)	0.10369
Maximum Demand of Greater than 500 kW									
Below 2kV									
Summer Season – On-Peak	0.00118	0.01239 (R)	0.00048 (R)	0.00723 (I)	0.00000	0.00485	0.02613 (I)	0.18694 (I)	0.10369
Mid-Peak	0.00118	0.01239 (R)	0.00048 (R)	0.00723 (I)	0.00000	0.00485	0.02613 (I)	0.09698 (I)	0.10369
Off-Peak	0.00118	0.01239 (R)	0.00048 (R)	0.00723 (I)	0.00000	0.00485	0.02613 (I)	0.04091 (I)	0.10369
Winter Season – On-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00118	0.01239 (R)	0.00048 (R)	0.00723 (I)	0.00000	0.00485	0.02613 (I)	0.13166 (I)	0.10369
Off-Peak	0.00118	0.01239 (R)	0.00048 (R)	0.00723 (I)	0.00000	0.00485	0.02613 (I)	0.04391 (I)	0.10369
From 2kV to 50kV									
Summer Season – On-Peak	0.00096	0.01689 (R)	0.00048 (R)	0.00698 (I)	0.00000	0.00485	0.03016 (I)	0.20062 (I)	0.10369
Mid-Peak	0.00096	0.01689 (R)	0.00048 (R)	0.00698 (I)	0.00000	0.00485	0.03016 (I)	0.10618 (I)	0.10369
Off-Peak	0.00096	0.01689 (R)	0.00048 (R)	0.00698 (I)	0.00000	0.00485	0.03016 (I)	0.05096 (I)	0.10369
Winter Season – On-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00096	0.01689 (R)	0.00048 (R)	0.00698 (I)	0.00000	0.00485	0.03016 (I)	0.13850 (I)	0.10369
Off-Peak	0.00096	0.01689 (R)	0.00048 (R)	0.00698 (I)	0.00000	0.00485	0.03016 (I)	0.05403 (I)	0.10369
Above 50kV but Below 220kV									
Summer Season – On-Peak	0.00080	0.00531 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01721 (I)	0.16075 (I)	0.10369
Mid-Peak	0.00080	0.00531 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01721 (I)	0.09330 (I)	0.10369
Off-Peak	0.00080	0.00531 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01721 (I)	0.05596 (I)	0.10369
Winter Season – On-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00080	0.00531 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01721 (I)	0.12321 (I)	0.10369
Off-Peak	0.00080	0.00531 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01721 (I)	0.05934 (I)	0.10369
At 220 kV									
Summer Season – On-Peak	0.00080	0.00019 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01209 (R)	0.15992 (I)	0.10369
Mid-Peak	0.00080	0.00019 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01209 (R)	0.09247 (I)	0.10369
Off-Peak	0.00080	0.00019 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01209 (R)	0.05514 (I)	0.10369
Winter Season – On-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00080	0.00019 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01209 (R)	0.12241 (I)	0.10369
Off-Peak	0.00080	0.00019 (R)	0.00048 (R)	0.00577 (I)	0.00000	0.00485	0.01209 (R)	0.05851 (I)	0.10369

(Continued)

Schedule DA-CRS Sheet 1

DIRECT ACCESS COST RESPONSIBILITY SURCHARGE

APPLICABILITY

Applicable to Direct Access (DA) Customers including those classified as continuous DA customers, DA-eligible Customers, and Transitional Bundled Service (TBS) customers. Service under this Schedule shall be subject to certain exemptions and exceptions as set forth below. (T) | (T)

Direct Access, where customers can purchase electricity from an Electric Service Provider (ESP), instead of regulated electric utilities, was suspended on September 20, 2001, by Commission Decision (D.) 01-09-060. This means that Direct Access is not available to new customers. Existing Direct Access Customers may continue on Direct Access service either with their current ESPs or with other ESPs, according to the Direct Access Suspension rules set forth in Decision (D.) 02-03-055, as modified by D.03-04-057, D.04-07-025, and D.04-02-024, as well as the Switching Exemption Rules set forth in D.03-05-034. (T) | | | (T)

Pursuant to Resolution E-3843, continuous DA Customers are those customers who switched to DA service on or before February 1, 2001 and never switched back to Bundled Service, or did not switch back to Bundled Service until after September 20, 2001. By D.04-08-039, refunds are due to continuous DA Customers who paid a DA CRS prior to December 4, 2003. DA-eligible Customers have Historical Procurement Charge obligations, as specified in D.04-09-004, which modified Resolution E-3843. (T) | | | (T)

DA-eligible Customers are those customers who received DA service prior to the suspension of DA service on September 20, 2001 or who were placed on an ESP list pursuant to D.02-03-055 because they had a DA contract in effect as of September 20, 2001. A DA-eligible Customer may be either a DA or Bundled Service Customer at the present time and still be considered DA-eligible. For DA-eligible Bundled Service Customers, see Schedule DAEBSC-CRS. (T) | | | (T)

As described in Rule 22.1, TBS allows DA Customers to return to Bundled Service on a transitional basis while switching from one ESP to another, or for similar or related reasons where TBS is needed. TBS customers are served under Schedule PC-TBS in conjunction with the payment of charges under Schedule DA-CRS for those customers to whom Schedule DA-CRS is applicable. (N) | | (N)

TERRITORY

Within the entire territory served.

RATES

All charges, terms, and conditions of the customer's otherwise applicable rate schedule, or contract rate shall apply, except that the customer's total bill shall be adjusted as follows:

(Continued)

Southern California Edison
Rosemead, California

Revised Cal. PUC Sheet No. 39821-E
Cancelling Revised Cal. PUC Sheet No. 39576-E

Schedule DA-CRS
DIRECT ACCESS COST RESPONSIBILITY SURCHARGE

Sheet 2

(Continued)

	DA-CRS				DA-CRS-UC
Rate Group	DWRBC	HPC*	CTC	DWRPC	
Domestic [1]	$0.00485	$0.01000	$0.01215 (I)	$0.00000 (R)	$0.02700
GS-1 [2]	$0.00485	$0.01000	$0.01215 (I)	$0.00000 (R)	$0.02700
TC-1 [3]	$0.00485	$0.01000	$0.00622 (I)	$0.00593 (R)	$0.02700
GS-2 [4]	$0.00485	$0.01000	$0.01149 (I)	$0.00066 (R)	$0.02700
TOU-GS [5]	$0.00485	$0.01000	$0.00713 (I)	$0.00502 (R)	$0.02700
TOU-8-Sec [6]	$0.00485	$0.01000	$0.00909 (I)	$0.00306 (R)	$0.02700
TOU-8-Pri [6]	$0.00485	$0.01000	$0.00827 (I)	$0.00388 (R)	$0.02700
TOU-8-Sub [6]	$0.00485	$0.01000	$0.00665 (I)	$0.00550 (R)	$0.02700
PA-1 [7]	$0.00485	$0.01000	$0.01180 (I)	$0.00035 (R)	$0.02700
PA-2 [8]	$0.00485	$0.01000	$0.00850 (I)	$0.00365 (R)	$0.02700
AG-TOU [9]	$0.00485	$0.01000	$0.00609 (I)	$0.00606 (R)	$0.02700
TOU-PA-5 [10]	$0.00485	$0.01000	$0.00854 (I)	$0.00361 (R)	$0.02700
St. Lighting [11]	$0.00485	$0.01000	$0.00004 (I)	$0.01211 (R)	$0.02700
System	$0.00485	$0.01000	$0.01024 (I)	$0.00191 (R)	$0.02700

1 Includes Schedules D, D-APS, D-APS-E, D-CARE, DE, DM, DMS-1, DMS-2, DMS-3, DS, TOU-D-1, TOU-D-2, TOU-D-CPPF-1, TOU-D-CPPF-2, TOU-D-SPP-1, TOU-D-SPP-2 and TOU-EV1.
2 Includes Schedules GS-1, GS-APS, GS-APS-E, TOU-EV-3, TOU-GS-1, TOU-GS1-CPPV-1, TOU-GS1-CPPV-2, TOU-GS1-SPP-1 and TOU-GS1-SPP-2.
3 Includes Schedules TC-1 and WTR.
4 Includes Schedules GS-2, GS-APS, GS-APS-E, GS2-TOU-CPP, TOU-GS2-CPPV-1, TOU-GS2-CPPV-2, TOU-GS2-SPP-1 and TOU-GS2-SPP-2.
5 Includes Schedules TOU-GS-2, TOU-EV-4 and TOU-GS-2-SOP
6 Includes Schedules TOU-8, I-6, TOU-BIP, RTP-2, RTP-2-I, TOU-8-BU, TOU-8-CPP, TOU-8-SOP and S.
7 Includes Schedule PA-1.
8. Includes Schedule PA-2.
9. Includes Schedules TOU-PA, AP-I, PA-RTP, TOU-PA-CPP, TOU-PA-7, and TOU-PA-SOP.
10. Includes Schedule TOU-PA-5.
11. Includes Schedules AL-2, DWL, LS-1, LS-2, LS-3, and OL-1.
* For DA-eligible customers the HPC is prorated using the formula in Section A.2. of this Schedule for billing effective 12/04/03 forward.

(Continued)

Schedule DA-CRS Sheet 3

DIRECT ACCESS COST RESPONSIBILITY SURCHARGE

(Continued)

RATES (Continued)

A. Direct Access Cost Responsibility Surcharge (DA-CRS):

Listed in priority order, the DA-CRS is composed of the following elements:

1. Department of Water Resources (DWR) Bond Charge to recover the interest and principal of DWR bonds. Pursuant to D.02-11-022, the DWR Bond Charge shall not apply to continuous DA customers as defined in the Applicability Section of this Schedule. (T)

2. Historical Procurement Charge (HPC) is a nonbypassable charge to recover DA Customers' share of SCE's Procurement Related Obligations Account. DA-eligible Customers who took DA service during the entire PROACT recovery period of September 1, 2001 to July 18, 2003, will pay the full HPC. DA-eligible Customers who were on Bundled Service during the entire PROACT recovery period are exempt from HPC. Effective with Decision (D.) 04-09-004, DA-eligible Customers who received both DA service and Bundled Service during the PROACT recovery period will pay a prorated HPC on going from December 04, 2003 until the DA Customers' share of the PROACT balance is fully recovered. Any DA-eligible Customer who returned to Bundled Service prior to July 27, 2002 and remains on Bundled Service until the DA Customer's share of the PROACT balance is fully recovered will remain HPC exempt. (T)

DA-eligible Customers, who are also eligible for a prorated HPC, were provided a one-time option select to pay their HPC obligation as a Lump Sum. (T)

a. CALCULATION TO PRORATE HPC

$$\frac{\text{(Days in PROACT Recovery Period – Days on Bundled Service)}}{\text{(Days in PROACT Recovery Period)}} \times 1 \text{ cent/kWh HPC}$$

b. LUMP SUM CALCULATION

(A-B) x C = Lump Sum

Where:

A = 2.62 cents/kWh x customer's kWh usage during those months of PROACT recovery period spent on DA service

B = HPC payments made since August 2002 when HPC became applicable

C = One (1) plus the applicable interest rate if the HPC payment is made after the PROACT balance was recovered. The applicable interest is that adopted in D.03-07-030 for DA Cost Responsibility Surcharge undercollection.

SCE will provide refunds or bill credits for customers whose past PROACT contributions exceed their HPC obligations. If the total amount of HPC is reduced as a result of the Proration the total CRS will not be increased to the 2.7 cents/kWh level.

3. Charge to recover the above market costs of utility retained generation known as Competition Transition Charge (CTC) ; and

4. DWR Power Charge to recover the DA Customers' share of DWR contracts costs after 2002 as determined pursuant to the methodology adopted in D.02-11-022, and its successor decision(s);

5. DWR Power Charge to recover undercollections of costs assigned to DA Customers for the period of September 20, 2001 through the end of 2002;

Continuous DA customers shall be exempt from the DWR Bond Charge and DWR Power Charge components of the DA-CRS. Pursuant to Rule 22.1, continuous DA Customers that commit to receive Bundled Service for a three-year period shall also retain their continuous DA status if they resume DA service at the end of their three-year commitment. (T)

(Continued)

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Rosemead, California | Cancelling Revised | Cal. PUC Sheet No. | 37084-E

Schedule DA-CRS Sheet 4

DIRECT ACCESS COST RESPONSIBILITY SURCHARGE

(Continued)

RATES (Continued)

A. Direct Access Cost Responsibility Surcharge (DA-CRS): (Continued)

Pursuant to D.02-12-045, for customers that were not continuously DA from February 1, 2001 to September 20, 2001, the DA-CRS will be set at an interim level of 2.7 cents/kWh. The DA-CRS consists of the DWR Bond Charge, the HPC, the DWR Power Charge and the CTC as displayed on the DA-CRS rate component chart in this Schedule. (T)

Pursuant to D.04-09-004, applicable customers who received both DA service and Bundled Service during the PROACT period from September 1, 2001 to July 18, 2003 will pay a prorated HPC determined by the formula described in Section A.2.a above. All other factors of the DA-CRS remain the same as described below. (T)

The DA-CRS is determined by multiplying the customer's total kWh for the billing period by the applicable level of 2.7 cents/kWh for non-continuous DA Customers, 1.7 cents/kWh for HPC-exempt DA Customers, 1.7 cents/kWh plus the prorated cents/kWh for those DA-eligible Customers pursuant to D.04-09-004, or 1.0 cents/kWh for continuous DA Customers. (T)

California Alternate Rates for Energy (CARE) and medical baseline eligible DA customers are exempt from the HPC and the DWR Bond Charge.

Except for the CTC, CARE and medical baseline eligible DA customers are exempt from the DA-CRS. Pursuant to Resolution E-3813, this exemption will apply on a prospective basis from June 30, 2003 which is the filing date of Supplemental Advice 1674-E-A. (T)

B. Direct Access Cost Responsibility Surcharge Undercollection Charge (DA-CRS-UC):

The DA-CRS-UC is the shortfall resulting from the difference between the revenues received from this Schedule and actual costs. The DA-CRS-UC will commence once SCE has determined that the DA-CRS-UC period (September 20, 2001 until the DA-CRS revenues exceed the then-current DA-CRS revenue requirement) has ended. The Commission has limited the DA-CRS. Revenues that are uncollected from DA Customers due to the Commission imposed limit will be collected from these same customers regardless whether these customers are taking DA or Bundled Service in the future. SCE will begin assessing the DA-CRS-UC when the then-current DA-CRS revenue requirement is less than the revenue collected by the DA-CRS. (T)

(1) The actual charge for the DA-CRS-UC as well as any necessary detail shall be added to this Schedule before the charge is implemented and will be subject to final Commission approval.

(2) The DA-CRS-UC charge shall be a proportion of rate assessed for the under-collection for customers that had been DA for the entire period from September 20, 2001, until DA-CRS revenue exceeds the then-current DA-CRS Revenue requirement (the "DA-CRS-UC period").

(3) The proportion paid by each customer shall be a function of the period of the customer had taken DA service, or had taken Bundled Service and paid the DA-CRS, during the DA-CRS-UC period. (T)

(4) All customers who took DA service during the DA-CRS-UC period shall pay the DA-CRS-UC except to the extent that DA Customers did not contribute to the undercollection such customers are exempt from the DA-CRS-UC. Customers cannot avoid this charge by election of bundled or DA service. (T)

(5) Payment of the DA-CRS-UC shall continue until the DA-CRS-UC is recovered (the "DA-CRS recovery period"). The DA-CRS recovery period shall end for all customers at the same time.

CURRICULUM VITAE

Richard Louis Simon

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GENERAL

Mr. Simon is a consulting meteorologist with 27 years professional experience. He has a wide background, with emphases in wind energy, air pollution, climatology, managing field programs, basic and applied research, and expert testimony for litigation.

EDUCATION

BA in Geography, University of California at Berkeley, 1973

MS in Meteorology, San Jose State University, 1976. Dissertation topic: the summertime stratus over the eastern Pacific Ocean. GPA: 4.0/4.0

PROFESSIONAL EMPLOYMENT

1975-1976	Research Associate, San Jose State University. I collected and processed wind data for NASA/Ames in connection with expansion of their wind tunnel and analyzed data for several NSF grants.
1976	Meteorologist, National Environmental Satellite Service (now part of the National Weather Service), Redwood City, California. I prepared graphics from satellite imagery to support marine fishermen.
1976	Laboratory instructor in synoptic meteorology, San Jose State University.
1977-1978	Instructor, Metropolitan Adult Education Program, San Jose, California. I taught aviation weather to pilots.
1977-1980	Co-founder and co-owner, Global Weather Consultants, Inc., Palo Alto, California (president 1978-1980). The company specialized in air pollution, wind energy, and customized weather forecasting for the media and agriculture. We prepared several reports for the Bureau of Land Management on air pollution in the California desert.
1980-1982	Meteorologist, Pacific Gas and Electric Company, San Francisco, California. My areas of responsibility included wind energy (field measurements, computer programming, data analysis), geothermal

(pollutant dispersion studies), and nuclear (emergency response planning for Diablo Canyon Power Plant).

1982-1983	Senior Meteorologist, American Energy Projects, Palo Alto, California. This was one of the original private developers of wind energy projects. I was responsible for property acquisition, siting of wind turbines, and evaluation of turbine performance.
1983-2002	Sole proprietor of meteorological consultancy to the public and private sector, with primary emphasis on wind energy development across the world.
1986	Lecturer in upper-division climatology course, Department of Meteorology, San Jose Sate University.
2003-present	Managing director, Windots, LLC. This is an extension of my sole proprietorship from 1983-2002, but now as an LLC.

ORGANIZATIONS

American Meteorological Society, member since 1979. Officer of Northern California Chapter, 1981-1984.

American Wind Energy Association, member since 1988. Received special award in 1998 for “critical contributions to the development of wind energy in the United States and around the world.”

Who’s Who in the West, listed since 1992.

PROJECTS / ACTIVITIES

1977 – Present	Consultant to the wind energy industry. I have worked with developers, government agencies, turbine manufacturers, and members of the financial and insurance communities. I have directly participated in the siting of more than 7000 commercial-scale wind turbines across the world. I have helped pioneer many techniques for wind resource assessment and siting.
1978-1980	Subcontractor to Pacific Gas and Electric Company in their initial wind energy assessment programs. I was responsible for meteorological tower installations, data collection and data processing.
1978 – Present	Meteorological research and expert witness for the legal community on approximately 150 cases. Cases have involved weather conditions during accidents (airplane, highway, marine, flood, wind), solar and lunar positions (ambient light levels), due diligence, misrepresentation, and climate evaluation. In 1989, I published an article for the American Jurisprudence Proof of Facts, 3rd Series, discussing meteorology and the law.

1978 – present	Consultant to Hodges & Shutt, an airport planning group. I helped them evaluate the merits of new airports or modifications to existing ones.
1979	Consultant to the U. S. Bureau of Reclamation wind resource study in northern and central California for potential wind farm development.
1981	Subcontractor to Sonoma County, investigated impact of a new waste water treatment plant on fog formation at the Santa Rosa airport.
1984	Gave seminar on meteorology to the East Bay Regional Park District, Berkeley, California.
1984, 1988	Participant in the Career Planning and Placement program, San Jose State University.
1985 – 1986	Consultant to Pacific Gas and Electric Company. Planned and conducted the first field study of wake losses at an operating wind farm.
1986	Subcontractor to United Industries Corporation, Bellevue, Washington, on study funded by the Electric Power Research Institute called "Wind turbine micrositing status and requirements assessment." I reviewed state-of-the-art techniques.
1986 – 1990	Subcontractor to United Industries Corporation, Bellevue, Washington, on a study funded by the U. S. Department of Energy, called "A numerical model for predicting wind turbine array performance in complex terrain." My responsibility was to plan and conduct various field programs, analyze historical wind farm production data, and help develop the computer model itself.
1987 – 1988	Consultant to the Delta Diablo Sanitation District, Antioch, California. I monitored background conditions for a proposed new landfill in eastern Contra Costa County.
1988 – 1989	Consultant to Systems Applications, Inc., and Sonoma Technology, Inc., in helping to plan air pollution field studies in the Sacramento and San Joaquin Valleys, sponsored by the California Air Resources Board.
1988 – 2001	Consultant to Waste Management, Inc. I collected and analyzed meteorological data to support air quality permits for proposed new landfills and operational planning at existing landfills.
1989	Consultant, Lawrence Livermore National Laboratory, on a meteoro-logical instrument package for testing a new type of wide field-of-view camera.

1989 – 2000	Consultant to Florida Power and Light on various alternative energy projects. In 1992 I prepared a wind energy resource assessment for the state of Florida.
1989 – 1992	Collected and processed wind data for the Golden Gate Bridge District's study of wave erosion near the Larkspur Ferry Terminal.
1990 – 1994	Consultant to the Contra Costa Water District, Concord, California. I developed plans for meteorological monitoring at the proposed new Las Vaqueros Reservoir site and served as an in-house technical contract monitor on three research projects.
1990 – 2000	Collected wind data for Fernau & Hartman, architects, to help plan homes for optimal energy efficiency.
1990 – 1991	Worked with Bill Graham Productions to evaluate wind conditions at proposed new outdoor ampitheatre locations in the San Francisco Bay Area.
1991	Assisted in the design of a meteorological monitoring program for Lawrence Berkeley Laboratory (University of California).
1992	Worked with Pacific Gas and Electric legal staff regarding meteorological conditions associated with the Oakland fire of October 1991, which burned several thousand homes.
1992 – 1994	Performed solar and wind energy feasibility study for the Livermore family in Napa and Lake Counties, California.
1994	Collected weather data at two locations in San Francisco to support the planning of the Pac Bell baseball park for the San Francisco Giants.

MAJOR PUBLICATIONS

1977	The summertime stratus over the eastern Pacific Ocean. Monthly Weather Review, October 1977.
1978	(with A. Miller) Wind resource potential in California. California Energy Commission report P500-80-052.
1980	Location of sites in northeastern California for wind power development. Published by the California Energy Commission, April 1980.
1980	The air quality impact of future development at Stapleton International Airport, Denver, Colorado. Submitted to Peat, Marwick & Co.
1980	Wind energy resource assessment—southwest region. Battelle Pacific Northwest Laboratories report PNL-3195 WERA-9, Richland, Washington.

1981	Potential errors in using only one anemometer to characterize the wind power over an entire rotor disk. Proceedings of the Large Horizontal Axis Wind Turbines workshop, Cleveland, Ohio. NASA Conference publication 2230, pp. 427-445.
1982	Wind energy monitoring systems. Presented at the workshop "Wind as an energy alternative for the Caribbean," sponsored by the Caribbean Association of Universities and Research Institutes, Bridgetown, Barbados.
1982	Wind energy site evaluations, Solano County and Altamont Pass. Pacific Gas and Electric Company.
1983	(with J. Eckland) Siting and wind farm development. Presented to the Wind Energy Committee of the ASME Petroleum Division at the Energy Sources Technology Conference, Houston, Texas.
1984	Eisenhower's meteorological support for the D-Day invasion. Chapter 3 of the proceedings for the symposium "Some meteorological aspects of the D-Day invasion in Europe," published by the American Meteorological Society. Paper presented at conference, Fort Ord, California.
1986	Wind farm array effects. Submitted to Pacific Gas and Electric Company, San Ramon, California. First field-based study of wake losses in energy production at an operating wind farm.
1987	(with P. Lester) Typical meteorological conditions between the Alton Coal Project Area and Bryce Canyon National Park, Utah. Submitted to Utah International, San Francisco, California.
1987	Wake effects in a Fayette 95-IIS wind turbine array. Solar Energy Research Institute report WERI/STR-217-3186, Golden, Colorado.
1988	Results of a detailed field program to evaluate micrositing tools. Proceedings of the American Wind Energy Association's Windpower '88 conference, Honolulu, Hawaii, pp. 541-559.
1989	Twelve years of wind resource assessment in California—how can the world benefit from what has been learned? Proceedings of the European Wind Energy Conference and Exhibition, Glasgow, Scotland, pp. 858-862.
1989	Meteorological conditions at a particular time and place. Volume 5 of <u>Am Jur Proof of Facts 3d</u>, pp. 191-321, published by Bancroft-Whitney. Monograph on meteorology and the law.

1990 (with S. Veenhuizen) A numerical model for predicting wind turbine array performance in complex terrain—Phase II. Final technical report under U. S. Department of Energy's Small Business Innovative Research program, project No. 4386-86-II.

1991 (with R. Gates) Long-term interannual wind resource variations in California. Proceedings of the American Wind Energy Association's Windpower '91 conference, Palm Springs, California.

1992 Two examples of successful wind energy resource assessment. Presented at the American Wind Energy Association's Windpower '92 conference, Seattle, Washington.

1994 (with J. Schroeter) The CSW system wind energy resource assessment and long-range wind farm development strategy. Proceedings of the American Wind Energy Association's Windpower '94 conference, Minneapolis, Minnesota, pp. 131-139.

1996 (with M. Brower and P. Hurley) A GIS-assisted approach to wide-area wind resource assessment and site selection for the state of Colorado. Presented at the American Wind Energy Association's Windpower '96 conference, Denver, Colorado.

1997 Potential wind energy monitoring sites in New Mexico: results of a field trip to inspect prospective sites. Published by the State of New Mexico Energy, Minerals and Natural Resources Division, Santa Fe, New Mexico, under contract No. 96-521.03-198.

PERSONAL

Born Oakland, California, 1950. Married 1985, two children. Interests include music (composition and performance), travel, linguistics and outdoor sports. Moderate fluency in the Russian and Italian languages.

December 2004

LIST OF PRINCIPAL WIND ENERGY CLIENTS
AND SUMMARY OF WORK PERFORMED

Richard L. Simon, MS, Consulting Meteorologist
Windots, LLC
10 Tartan Road, Mill Valley, California 94941 USA

GOVERNMENT AGENCIES

California Energy Commission: co-authored initial wind energy resource evaluation of California (1978), Principal Investigator (PI) of Northeastern California field measurement project (1987-1980), Fandango Pass wind data collection (1979-1980), assistance with various other studies.

Contra Costa Water District: evaluated wind resource and potential climate changes due to construction of Los Vaqueros Reservoir near Altamont Pass (1990-1993). Member of Technical Advisory Task Force to help implement public use programs (1995-1998).

U. S. Bureau of Reclamation: recommendations for wind prospecting study on coastal mountains of California to support plans to add wind to their electrical generation mix (1979). This included trips across the state to identify specific locations for wind measurements.

U. S. Department of Energy: PI on “Wind energy resource atlas, Volume 9—the Southwest region” (California and Nevada, 1979-1980). PI on wind turbine array wake effect study in Altamont Pass sponsored by the Solar Energy Research Institute (1985-1987). Subcontractor on United Industries Corporation study to develop a numerical model for predicting wind turbine performance (1986-1990), which combined three-dimensional wind flow and wake models and was verified against actual field data. Attended wind resource work shop in Risø, Denmark under sponsorship of the National Renewable Energy Laboratory (1998).

UTILITIES

American Electric Power (formerly Central and Southwest Services): PI on multi-year field measurement study to investigate wind energy potential across their service territory in Texas, Oklahoma, Arkansas and Louisiana (1993-present). Also wind farm planning and power performance testing of turbines.

Douglas County Public Utility District: establish field measurement study in this central Washington county, process and analyze data collected from the monitoring network (2001).

Electrical Power Research Institute: subcontractor in study to document state-of-the-art in wind turbine micrositing and wind resource projections (1986). PI in study to review wind resource potential for Central Maine Power (1993-1994).

Florida Power and Light: report on wind resource potential across the state of Florida, including field trip to examine prospective sites (1992). Miscellaneous consulting on their wind energy projects in California (1989-2000), Oregon (1996-1998), and new project opportunities across the United States, Europe and South Pacific.

Grant County Public Utility District: site visits to select locations for monitoring wind in this central Washington County, train Utility crew to install anemometers, process/analyze the data (2002-present).

Idaho Power, PacifiCorp, Puget Sound Power & Light, Portland General Electric: consultant to their planning of a jointly-owned wind farm in central Washington (1992-1996).

Pacific Gas and Electric Company: installed and operated 24-station wind energy monitoring network in central California (1978-1980). Employee (1980-1982), with emphasis on field data collection and analysis, strategic planning for wind energy, and presentation of papers at conferences. Performed the very first field study of array wake effects (1985-1986). Wind resource analysis and turbine layout for Madison, NY wind farm (1999-2000). Due diligence and technical consulting for new wind farm projects in California (2000-present).

PacifiCorp: consultant in planning of wind farms and subsequent operational evaluation in Wyoming (1993-present). Review of wind farm potential in California (1999-2000).

Statkraft: planning and implementation of long-term wind resource assessment and development program for the largest utility company in Norway (1997-2000).

DEVELOPERS AND MANUFACTURERS

Advanced Energy Corporation: assessments of wind energy potential in Ireland (1989), New England (1991) and Altamont Pass (1991).

Altamont Energy Corporation: evaluation of wind resource potential for properties in Altamont Pass (1982-1986).

American Diversified Capital Corporation: wind data analysis and intensive field measurements to support planning of two wind farms in Altamont Pass (1984-1985).

American Energy Projects: consultant and employee on planning of wind farms in California (1981-1984), collecting and analyzing data, siting turbines, land acquisition.

Arcadian Renewable Power: supervising wind data collection and analysis for monitoring network in Altamont pass (1989-1998), analysis of re-powering Altamont wind farms (1992-1996).

Arbutus Corporation: prepared report on wind energy potential in Nevada (1984), technical support (numerical modeling and wake study) for litigation against turbine manufacturer at their Tehachapi wind farm (1991).

Atlantic Renewable Energy Corporation: wind studies, site visits, array layout and energy projections for project sites in the eastern United States (1999-2000).

Cal Wind Resources: assisted in identification of prospective wind farm sites in southwestern United States (1994).

Cannon Power Corporation: resource assessment for new wind farm in Tehachapi Pass (1993-1994). Resource evaluations and site visits of properties in Switzerland, Portugal, India, Italy, Spain and Turkey (1993-present).

Carter Wind Turbines: investigated potential development sites in the Midwest (1993).

Clipper Windpower: lsupport in wind farm planning (2000-present).

Congena: resource assessments and siting plans for various California properties (1986-1991). Installed and operated anemometer networks in Altamont and Tehachapi Passes (1989-1991). Power performance testing of turbines (1990).

Continental Wind & Sunshine: conducted field measurement programs in southern California and Hawaii for prospective wind farm development (1987).

Dutch Pacific LLP: wind data processing and wind farm planning for project sites in the Philippines and India (1995-1998). Support on prospective development sites in the Unites States (2000-present).

Dutch Wind Energy Corporation: wind data collection, turbine siting, resource projection and expert witness in litigation for Tehachapi Pass wind farm (1990-1994). Re-projection of long-term production based on operational history (1999).

EDS, Inc.: due diligence reviews of two Tehachapi Pass wind farms in which EDS was a major equity partner (1989-1991). Follow-up analyses of actual production (1990-1995).

Enron Wind Corporation (formerly Zond Systems): resource assessment, turbine siting, analysis of wind farm production, power performance testing, long-term wind studies (1987-present). Co-authored several research papers (1991-1992). Evaluation of potential wind farm sites across the Unites States and foreign countries.

Fayette Energy Corporation: in charge of anemometer networks at Altamont Pass and other locations in California (1982-1989). Sited 1600 wind turbines in the Altamont (1982-1986). Land acquisition (1983-1987). Basic research on wind resource siting strategies and support in litigation.

FloWind: evaluation of long-term winds and weather in the San Francisco Bay Area (1984). Wind data editing and quality control (1986-1988). Compilation of historical wind records in California (1992-1993).

FPL Energy: due diligence reviews of six Tehachapi Pass wind farms (1989-1991). Follow-up analyses of project performance (1990-present). Evaluation of prospective sites in Europe and the South Pacific (1994-1997). Data analysis and micrositing layout for Oregon wind farm (1996-1998). Wake loss studies in Altamont Pass (1998-1999).

Global Energy Concepts (formerly RLA Consulting): subcontractor on GIS-based wind resource assessment in Colorado, including field visit (1995). General collaboration on various activities (1999-present).

Howden Wind Parks: complete wind resource assessment and turbine siting for their Altamont Pass wind farm (1984-1986). In charge of field measurement program for Solano County and testimony at public hearings (1985-1987). Long-term wind studies (1987-1988).

Italian Vento Power Corporation: wind data processing and analysis, turbine siting and wind resource assessment in Italy (1993-present).

Kenetech/U.S. Windpower: evaluation of long-term winds in California (1984). Resource assessment for acquired properties in Altamont Pass (1985). Consultant to utilities and banks on proposed projects (1992-1997).

Mackinaw Power: identification of prospective areas of Michigan for wind resource studies, recommendations for anemometers, and processing of wind data.

M&N Wind Power: review of project performance and estimate of long-term mean annual energy production for two wind farms in Quebec (2001).

Mogul Energy Corporation: resource assessment and turbine siting in Tehachapi Pass (1994-present). Power performance testing (1998-2001). Evaluation of new project site in Arizona (1999-present).

New World Power Corporation: resource assessments and strategic planning for new wind farms across the United States and several other countries (1993-1997).

Northwestern Wind Power: establishment of field monitoring programs, data processing and analysis, plus turbine siting for sites in Oregon and Washington (2001-present).

Phase II Builders: in charge of anemometer networks across California (1984-1986). Wind resource assessments and turbine siting for wind farms in Altamont, Pacheco and San Gorgonio Passes (1984-1987).

Princeton Development Corporation: wind data processing, turbine siting, and site visit to prospective development sites in Turkey (1996-2001).

<u>Ralph Ranches</u>: wind energy studies (field measurements, energy projections) for their land holdings in Altamont Pass (1987-present).

<u>SAA Ventures</u>: wind measurements and wind farm planning for a large site in the Texas panhandle (1997-present).

<u>Sea West</u>: evaluated wind resource for undeveloped areas in southern California (1984, 1993). Wind data collection, analysis, turbine siting and resource projections for Altamont Pass wind farms (1984-1985). Evaluated long-term production for existing Altamont wind farms and prospective re-development of same (1993). Evaluation of feasibility of relocating existing Tehachapi Pass wind farms (1995-1996). Wind data analysis, turbine siting and resource assessments for sites in Texas and Oregon (2000-present).

<u>Tera Power Corporation</u>: wind data analysis for the Delta wind farm in Altamont Pass (1984, 1994-1995).

<u>Tomen Power Corporation</u>: wind resource assessments for projects in the United States, Europe, India and Japan (1994-present).

<u>Union of Concerned Scientists</u>: assistance in small farmer-owned wind project for southwest Minnesota (1996-present).

<u>UPC Wind Energy, LLC</u>.: assistance with prospective wind farm studies (anemometer recommendations, data processing, site visits, turbine siting and resource projections) for sites in France (1996-2000), North America (2001-present) and Africa (1997-present).

<u>Vestas-American Wind Technology</u>: resource evaluations for prospective new wind farms in California (1993-1995) and Kansas (1998).

<u>Windfarms, Ltd</u>.: wind data input for strategic short- and long-term planning (1980-1981), field measurement programs across California (1980).

<u>Wind Harvest Company</u>: identification of high-wind sites in the United Kingdom (including several site visits) and supervision of wind data collection program (1989-1992). Wind data collection at prospective wind farm sites in California (1990-1992). Support with strategic planning (1999-present).

<u>Windmaster</u>: resource assessment in Altamont Pass (1984).

<u>Wintec, Ltd</u>.: analyzed 1998 winds in San Gorgonio Pass compared to normal (1998).

<u>Zilkha Renewable Energy</u>: support with data analysis for prospective wind farms in Minnesota and Kansas (2001).

OTHER

Credit Suisse/First Boston: due diligence reviews and ongoing production analyses for two Tehachapi Pass wind farms (1989-present). Due diligence on proposed projects in Europe (1994).

Fernau & Hartman: collected wind data to evaluate wind resource potential at home sites near the California coast (1990-1992, 1999).

Heller Financial, Inc.: due diligence for proposed and constructed wind energy projects in California (1993-present).

Montesol Company: wind energy field measurements for Napa and Lake Counties (1990-1994).

NationsBank: due diligence review and ongoing production analyses for several U.S. wind farms (1995-present).

Waste Management, Inc.: evaluated wind resource potential at existing and proposed landfills in central California (1988-1999).

LONG-TERM O&M COSTS OF WIND TURBINES BASED ON FAILURE RATES AND REPAIR COSTS

By: William A. Vachon
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ABSTRACT

Projections of 20-year operation and maintenance (O&M) costs are presented for typical utility-scale wind turbines that are being currently installed. The costs are governed by a Weibull statistical model that predicts failure rates of key components over the life of a project. The predictive model is adjusted based on prior field experience with similar components. Projections vary with (a) the robustness of a wind turbine design, (b) the environmental and wind conditions to which wind turbines are subjected, (c) the effectiveness of lubrication of mechanical parts, and (d) maintenance practices. A Weibull analysis approach is widely used for similar purposes by NASA, the military and industry. By combining the failure rates with representative repair times and associated costs for parts and labor, unscheduled maintenance costs can be predicted. Scheduled maintenance costs are also included. The key, long-term cost drivers are generally the failure rates and replacement or rebuild costs and expenses of gearboxes, generators and hydraulic systems. Associated expenses typically include those for labor, parts and cranes. The roles of cranes, for both on-shore and off-shore wind power plants, are discussed along with potential estimates of the benefits and savings derived from tower- or nacelle-mounted cranes.

1. INTRODUCTION

Developers, owners and lenders seek to establish accurate and credible pro forma projections of wind project financial performance. Important to all parties, especially to owners, are the wind turbine operation and maintenance (O&M) costs after the equipment warranties expire. The owners hope that O&M costs are reasonable after any lender notes are paid off - typically after 10 to 15 years of project operation. This is the period when the project assets could (a) provide a solid cash flow, (b) be resold to acquire cash or (c) the site could be repowered. However, there is a great uncertainty about the risks in any pro forma projections of late-year cash flows due to lack of knowledge of the long-term reliability of major large, costly components and the possible costs to remedy problems - should they arise. Much of the uncertainty arises from the fact that (1) most operating wind turbines have been installed during the past 18 years, (2) reliability records are not complete and clear, and (3) designs have increased in size since the 1980s - leading to questions about the applicability of reliability data derived from early installations.

This paper discusses component failure rates based on field experiences and accepted mathematical principles for estimating future failure rates. The failure rates are combined with costs associated with remedying the failure to estimate annual O&M costs for a 20-year period.

2. BACKGROUND

The nature of wind turbine equipment technical risks is summarized below.

Equipment Risks in Project Pro Forma. Some of the technical risks to the pro forma vary with the year of operation and some are always present. Wind risks are always present. In the early years, warranties generally cap the wind turbine risk for the warranty period. After that, the owner and lender must worry about the technical robustness and maintenance costs of the wind turbines. Generally the lender's notes will run from 10 to 15 years - sometimes longer. New US projects, that qualify for the Production Tax Credit (PTC), have an added revenue flow for the first ten years of operation that assists in paying the notes and providing a decent rate of return for the owners. In the later years the wind turbines and other equipment are aging and may need more maintenance and/or refurbishment. These costs will reduce the performance of the project pro forma if not properly estimated at the outset.

Recent Projections of O&M Costs. For mature turbines (turbines for which many have been manufactured and operated trouble free for at least two years) studies have indicated that the distribution of lost availability is due to outages caused by turbine faults due to electrical problems [Ref. 1]. Such losses result from the fundamental electrical component issues such as normal aging, high temperature, high voltage or voltage surges, vibration, and moisture. The literature, however, indicates that only a few studies have sought to define the long-term costs associated with maintenance caused by outages and mechanical and electrical component failures.

Based on approximately 10 years of experience, the maintenance costs of smaller U. S. wind turbines were modeled based on data from California projects [Ref. 2]. Recently, European researchers have sought to define the O&M costs for both on-shore and off-shore projects. The issue of O&M costs as a function of turbine age was addressed by Lemming et al [Ref. 3] and Hahn [Ref. 4], while the costs for an optimally sized, modern wind farm were estimated by Van Bussell and Zaaijer for the DOWEC project in Holland [Ref. 5]. There is not an abundance of good field reliability and cost experience.

Using elements of some reliability data bases, past professional papers, and anecdotal evidence derived through field visits and interviews with site personnel, it is, however, possible to develop a reasonable understanding of the typical lifetimes and repair costs for wind turbine components. This approach has been followed in this paper.

3. ANALYTICAL PROJECTIONS OF COMPONENT FAILURE RATES

O&M Cost Model. Figure 3-1 is a schematic representation of the manner in which O&M costs are calculated in the model for both on-shore and off-shore windfarms. In the top portion of the model, scheduled costs are shown - that generally consist of operations (turbine oversight, resets, crew dispatch etc.), preventive maintenance and general windfarm reporting to owners and lenders. Scheduled costs can generally be estimated with a fair degree of accuracy and will generally increase with the inflation rate on wages, parts and other office services.

The overall assumption in the O&M model is that site O&M is carried out by an independent third-party that provides operations, preventive (scheduled) and unscheduled maintenance and provides monthly, quarterly and annual reports to the owners and long-term lenders. In the early years of the project, scheduled services largely account for the site personnel count and costs. As the project ages, the cost factors listed at the bottom of the figure come into play. All costs are then summed - as shown in the right of the figure.

The unscheduled maintenance costs are shown in the lower portion of Figure 3-1. They are largely driven by the failure rates of the components in the wind turbine and the associated field costs to remedy the failures. Except for cases of poor design, or deficiencies in manufacture or installation, component failure rates are usually defined by normal wear out and life-shortening affects from environmentally induced damage. In this paper the following factors are assumed:

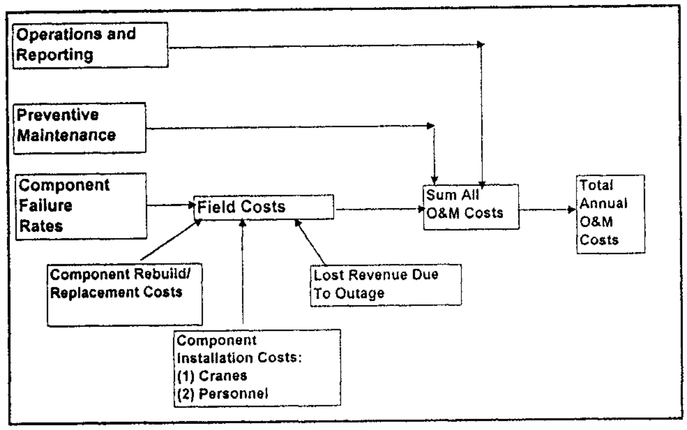

Figure 3-1. Diagram of Analytical O&M Model

a) Wind turbine designs are reasonably mature and not subject to the kinds of "surprises" that are often found in prototypes and demonstration machines,
b) State-of-the-art quality assurance measures have been applied to the wind turbine manufacturing and installation procedures, and
c) Quality assurance and design problems that are not discovered, and reach the field, are identified and remedied during the wind turbine warranty period.

The above factors usually hold true for the large, commercial wind turbines that are currently being marketed and installed in several countries by a host of wind turbine manufacturers.

<u>**Scheduled (Planned) O&M Costs**</u>. Typical scheduled costs, with cost categories listed in the top portion of Figure 3-1, are usually predictable but will vary with the type of personnel carrying out the tasks. If the owner of the windfarm is carrying out the tasks, the costs can be lower than if a subcontractor does the work - but not necessarily. Workers employed by the owners may cost as much as that for subcontractors if the company is in the O&M business and applies a substantial profit-oriented markup to labor costs. The same will almost always be true of subcontractors. In this paper, it is assumed that worker labor rates are marked up consistent with those of a subcontractor that is in the O&M business. Average, subcontracted field technician labor rates typically vary from $45 to $70 per hour. A fully burdened labor rate of $56 per hour is assumed in the model discussed herein.

The model includes the following specific major assumptions: (a) 100-MW module, (b) a 12-person site crew (5, 2-person maintenance teams, a site supervisor and a clerk), (c) 6 trucks, and (d) preventive maintenance at $12k/year in year one. The component failure rates are described by the Weibull statistical analysis model described below - where input to the model is based on an assemblage of component field experiences discussed above.

<u>**Unscheduled Maintenance Costs**</u>. Unscheduled maintenance costs are governed by the statistical failure rates predicted by the Weibull failure model. The Weibull analysis method is useful in predicting component wear out or failure rates [Refs. 6-9]. The procedure is based on knowledge of historical failure-rates for similar equipment that is operated in similar applications and environment. The model focuses on the use of a statistical, mathematical model to describe those failure rates. The general model approach is widely used in several industries that manufacture mechanical and electronic components - where suppliers must understand, predict and control equipment reliability well. To a limited extent the method has been applied to predict the failure of wind turbine components [Refs. 1 and 2].

<u>**Definitions**</u>: A given population of properly designed, manufactured and installed components will typically wear out or fail, over time, in a manner that is described by a "bell-shaped" curve.

The Weibull function is a two-parameter distribution that describes the probability of a failure each year, and provides sufficient mathematical flexibility to adjust the description to match most cases observed by components in service. Equation (3-1) is the generalized Weibull distribution for a given number of components.

$$\mathbf{f(t) = [b/\theta(t/\theta)^{b-1}] \exp [-(t/\theta)^{b}]} \qquad \mathbf{(3\text{-}1)}$$

where: f(t) is the component failure rate per unit of time, t, for a fixed component population,
t is time (typically hours or years of service),
b is the Weibull Shape (also called slope) Parameter,
θ is the Characteristic Life (also called scale parameter) at which time 63.2 percent of the initial population of components is expected to fail or wear out.

To determine the percentage of expected component failures after the passage of time T, equation 3-1 is integrated from time zero to time = T and results in the following:

$$\mathbf{F(T) = \int_{0}^{T} f(t)dt = 1 - \exp[-(T/\theta)^{b}]} \qquad \mathbf{(3\text{-}2)}$$

Figure 3-2 shows three Weibull distributions, where the value b=3.5 results in a typical symmetric, or normal Weibull distribution of failure rates. The mean life is the peak of the failure rate curve (for b=3.5), while the Characteristic Life is the time at which 63.2 percent of the original component population has failed.

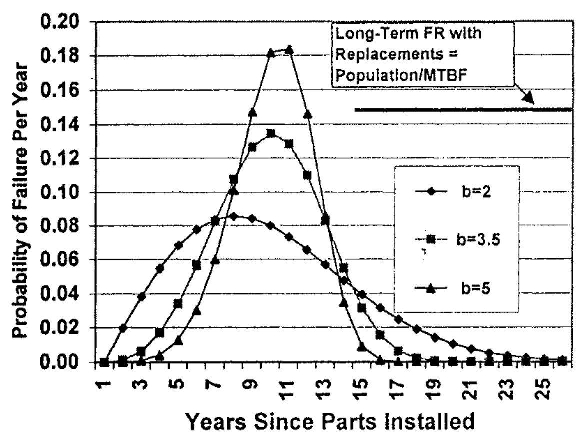

Figure 3-2. Typical Weibull Failure-Rate Curves

As shown in Figure 3-2, the value of b, the Shape Parameter, dictates whether the "bell-shaped" curve is symmetric about the mean life (when b=3.5), skewed left (for b< 3.5), or skewed right (for b>3.5). Shape Parameters of less than 3.5 typically indicate "infant mortality" due to design or quality issues. Shape parameters greater than 3.5 indicate good component longevity and normal wear out. For most wind turbine components it is often assumed that b=3.5 (i.e., a symmetric bell curve) until more solid information is known from field experiences. The expected failure rate in a given year (eg., between year T and year T+1) is determined as the difference between the cumulative failures after successive years (i.e., years T and T+1) by applying equation (3-2) for each year - to determine F(T+1) - F(T).

The mean life (i.e. MTBF or mean time between failures), in which 50 percent of the components are expected to fail, is a frequently reported parameter in reliability data. It is related to θ through Equation (3-4), which is derived by solving Equation (3-2) for t, while setting F(T) equal to 0.5, the probability of failure at the mean life.

$$\mathbf{MTBF = Mean\ Life = \theta * (\ln 2)^{(1/b)}} \qquad \mathbf{(3\text{-}3)}$$

When components are replaced each time they fail, the new components are then governed by the failure statistics shown in Figure 3-2 - leading to a long-term, average component failure rate that is equal to the population of components divided by the MTBF - as shown in Figure 3-2.

4. MODEL ASSUMPTIONS

4.1. Scheduled Costs

All scheduled and unscheduled costs in the O&M model include a 2.5-percent annual inflation rate. Scheduled costs include normal operations (monitoring, resets, etc.), reporting to the owners/ lenders, and equipment preventive maintenance (PM). The equipment includes distribution lines, pad-mount transformers and portions of substations. In the O&M model, year-1 site operations and reporting for a 100-MW project are estimated to cost $270k. Preventive maintenance (PM) is estimated to cost $12k per MW/year. In addition, PM consumables (rags, greases, degreasers, etc.) are added at a rate of approximately $600 per MW. The PMs require five, two-person crews, five four-wheel drive trucks - including associated tools and spare parts. In addition a maintenance foreman and a full-time office clerk are assigned to the site - with the addition of a sixth field truck for the foreman. As needed, substation workers and other specialists are brought in from the outside. Each two-person crew is responsible for 20 MW of wind turbines - or one-fifth of the site. The current model does not assume PM manpower efficiencies as the wind turbine size increases from the 600 to 750-kW range to multi-megawatt sizes. The field personnel allocation is believed to be liberal in the early years of project operation, but as equipment ages and wears experience has shown that the allocation may be insufficient to keep up with nuisance requirements. The model assumes that over 20 years, cost differences average out.

4.2 Unscheduled Costs

Unscheduled costs result from unplanned failures of the wind turbine parts, transformers, lines and substations. Costs for personnel, parts repair and cranes are added to the scheduled costs. In the work discussed herein, lost revenue has been neglected for the following reasons:

a) Repairs are assumed to completed in less than one to up to four days by swapping parts,
b) Costly failures of mechanical components occur slowly and allow field personnel to anticipate and plan a replacement such that there is little associated unscheduled outage, and
c) Spare or rebuilt parts are assumed to be readily available at either the site or at a regional depot operated by the wind turbine manufacturer - with little delay and associated wind turbine outage.

The model also includes an annual cost of $1,000 per MW for failures of electrical parts.

Component Failure Rates and Replacement Costs. Table 3-1 summarizes the assumed values for the Mean Time Between Failures (MTBF) of the major mechanical components in wind turbines that are prone to wear or failure. All components are assumed to be proven and generally reliable prior to project inception. The data are best estimates and based on the sources discussed. Generator lives vary considerably - depending on the manufacturer, the climate at the site and the maintenance practices (lubrication). Gearbox lives vary considerably with the manufacturer, type of lubrication, rating, type of gearing, and robustness of bearings The data assume that design or manufacturing defects or revealed during the warranty period. Blades have not been highlighted as a problem nor have they been seen to be a significant cost problem in the field for most projects that have blade problems remedied during the warranty period.

Replacement Parts Costs. In the O&M model, replacement costs for the parts listed in Table 3-1 are governed by cost algorithms that vary with the wind turbine size and are also based on a review of field experiences. In general, the model assumes that worn out mechanical parts are rebuilt - using new internal components or kits. Failed generators are assumed to be rewound. In some cases, generators also need to have the housings "resleeved" because bearings start to spin and erode the housing. These activities add to the costs. The cost algorithms seek to estimate the average costs for rebuilds and or replacements. Average gearbox costs assume that the gearboxes are removed from a turbine, taken to a shop and most bearings and some gears replaced. Figure 3-3 is a plot of the algorithms for average gearbox and generator rebuild costs.

Component	Components Per Turbine	MTBF (Years)
Gearbox	1	18
Generator	1	15
Blade	3	40+
Yaw Drive Motor	2-4	22
Yaw Drive Pinions	2-4	13
Yaw Bearing/Sliders	1	25
Hydraulic Power Units	1	15
Hydraulic Actuators	1-3	13

Note: MTBF is assumed invariant with turbine size.

Table 3-1. Estimates of MTBF for Key Mechanical Components of Mature Turbines

Parts Installation Costs. Installation costs for parts consist of crane lease costs and the personnel time to replace the failed part.

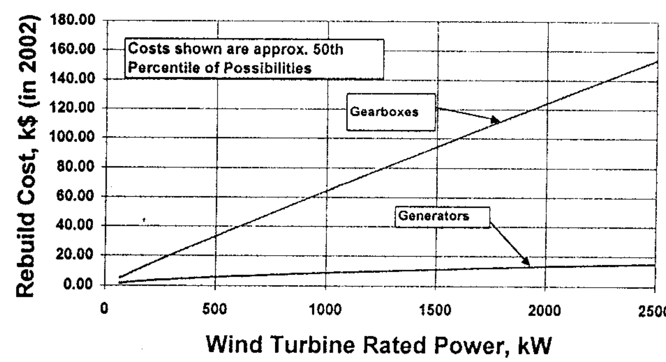

Figure 3-3. Estimated Rebuild Costs for Generators and Gearboxes

A. Crane Costs: Crane costs are a major concern in recent years as wind turbines have become larger. They are generally needed to replace blades, gearboxes, generators and yaw systems. There is a wide regional variation in crane costs within the US. Furthermore, crane costs in such European countries as Germany with (with a strong wind energy business base) are are significantly lower than in the US. A majorelement of crane costs is the cost of mobilization and demobilization - which is highly uncertain and varies with the crane size and distance from which a crane must be acquired. For 600 to 750-kW wind turbines, that have nacelles that weigh in excess of 20 tons, crane mobilization and demobilization may require more than 15 to 18 truckloads of components that must be assembled on site. Larger cranes require more equipment.

Figure 3-4 contains a portion of the cost algorithm for total crane mobilization plus demobilization costs as a function of the required lift weight for cranes available in North America. Because there is such a wide geographic variation in costs, and a variation with distance from the crane source to the windfarm, the figure provides estimates of the highest and lowest costs. The estimates in the figure assume that the wind turbine hub height is equal to the rotor diameter. The model allows these factors to be independent.

To estimate the full costs for a complete replacement of a major part, the cost for a four-day crane lease are developed based on actual data from various crane suppliers. The costs include mobilization/demobilization, three crane personnel, but do not include costs for a boom truck or smaller crane that is often used for tag lines and stability. It is assumed that a 100-MW site would own such a truck at a minimal marginal cost for each repair. The average data for North America are included in the crane cost algorithm and are summarized in Figure 3-5 as a function of lift height. The algorithm in the O&M model also brackets the expected lift weight of current large wind turbines that range from 600-kW to 2-MW.

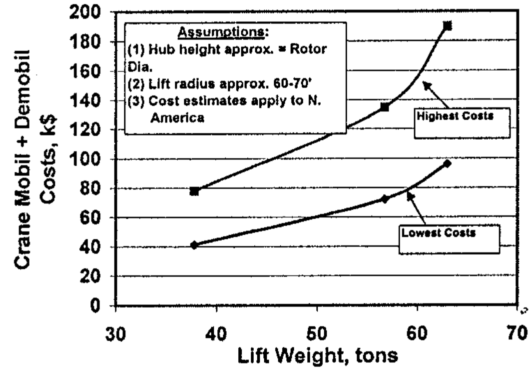

Figure 3-4. Estimated Cost Range for Crane Mobilization Plus Demobilization

Two adjustments are made to the crane costs shown in Figure 3-5 - to make them more realistic.

a) A cost adder of 12.5 percent is included to account for overtime and "blown out" times - when the winds are too strong to do crane work. The model assumes that one day in five is "blown out". The daily lease rate for such occasions is one-half the normal daily rate.
b) For years in which the need for a crane exceeds four, the crane cost is reduced to 75 percent of normal to account for efficiencies and the lack of multiple mobilizations. When the need exceeds 10 times per year, crane costs are adjusted to one-half for the same reason.

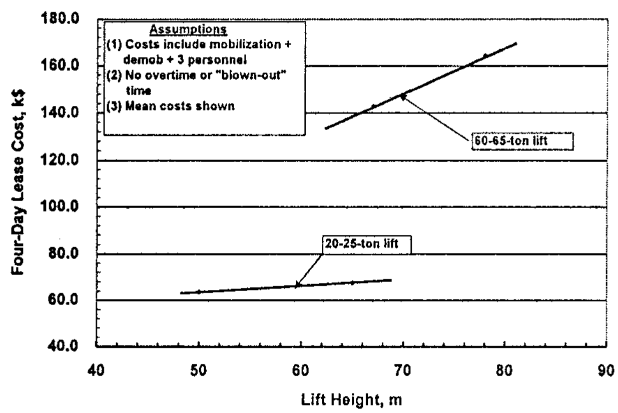

Figure 3-5. Estimated 4-Day Crane Lease Rates

B. Personnel Costs: To avoid double counting, many of the field technician personnel costs associated with repairs and parts installations are assumed to be covered by the standard site personnel costs discussed above. Further personnel costs are included in the rebuild costs discussed above.

5. ANALYSIS RESULTS

5.1. On-Shore Projects

At the present time, the vast majority of windfarms are located on shore.

Projections of Annual O&M Costs. Figure 3-6 provides a 20-year cost projection profile for scheduled, unscheduled and total O&M costs for a 100-MW site with a 3-year warranty on the wind turbines. The wind turbines are assumed to be in the 600- to 750-kW range. It should be noted that the unscheduled costs are nearly zero for the first three to five years - until failures begin to occur.

Figure 3-7 portrays the costs on a cents per kWh basis - assuming that the project performs at a net annual average capacity factor of 0.3. The Figure also includes the cost projections for a 100-

MW windfarm consisting of 2-MW wind turbines. It should be noted that the costs are slightly less for the larger wind turbines - especially in the later years. The reason for the lower costs is that, even though cranes and parts are substantially more costly, there are fewer total parts that fail.

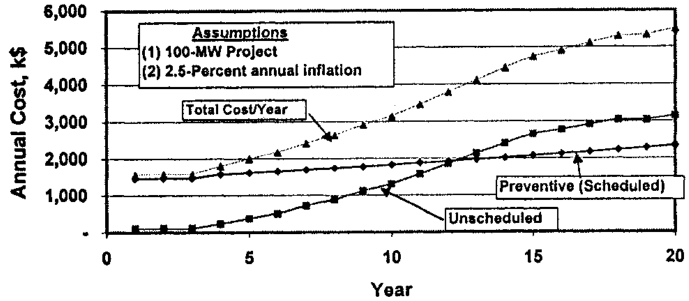

Figure 3-6. Annual O&M Costs Over 20 Years For 600- to 740-kW Wind Turbines

Cumulative O&M Costs. Figure 3-8 summarizes the 20-year cumulative O&M costs costs for two ranges of wind turbine sizes and for a range of hub heights. The The other assumptions are the same as described above and shown in the inset to the figure. The ordinate lists the costs in millions of dollars per MW (or dollars per watt). The estimates indicate that, over a 20-year period, the O&M costs for a project consisting of 2-MW wind turbines may be approximately 12 percent less than those for a project built with 600 to 750-kW wind turbines.

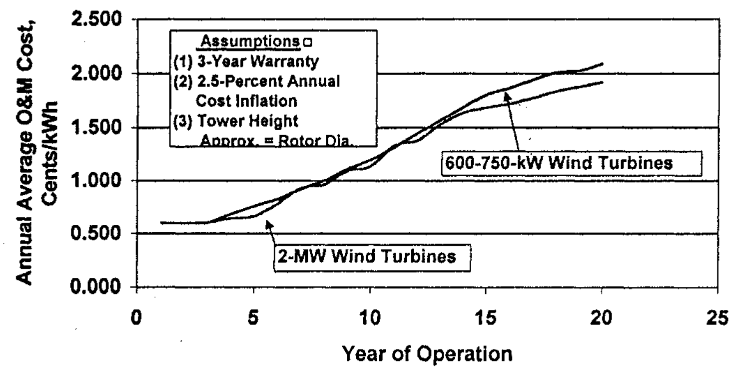

Figure 3-7. Annual O&M Cost/kWh for Medium and Large Wind Turbines

Wind projects are currently being installed for costs of approximately one million dollars per MW. Thus, the cost projections indicate that over 20 years the cumulative O&M costs can be on the order of 75 to 90 percent of the project installed cost.

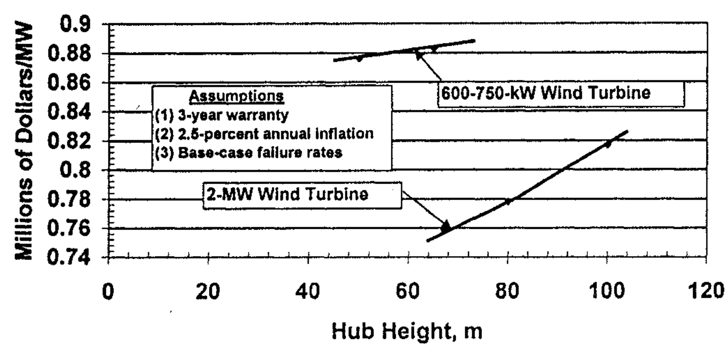

Figure 3-8. 20-Year Cumulative O&M Costs

Allocation of Costs. The estimated allocation of costs for a project consisting of 2-MW wind turbines were estimated for for turbines in which the hub height is equal to rotor diameter. The model indicates that unscheduled maintenance accounts for 52 percent, scheduled maintenance at 39 percent and the remainder for operations and reporting. Scheduled costs appear to be high, but the O&M model allocates costs for all site personnel and trucks under scheduled maintenance.

Figure 3-9 indicates how the unscheduled maintenance costs break out for the same case described above. It is clear that the dominant unscheduled costs are for cranes (41.4 %), gearboxes (15.9 %) and hydraulic power units (13.4 %). Although is has been documented that electrical issues lead to the most outages, this study estimates that remedies are very often quick and not high in cost.

The high proportional cost for cranes suggests the use of cranes that are integral to the nacelle or tower. Such cranes, and their supporting structure and rigging, can be designed to lower the heaviest components from the nacelle. This concept was analyzed with the O&M model - assuming that when an integral crane is employed, the cost is estimated to be 15 percent of the normal 4-day rate for cranes (see Figure 3-5). Later in this paper evaluation is made of integral cranes for use in both on-shore and off-shore wind projects.

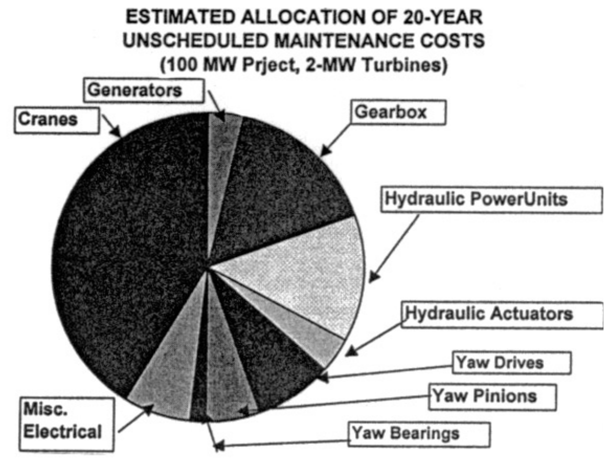

Figure 3-9. Allocation of Unscheduled Maintenance Costs

5.2. Off-Shore Projects

There is a lack of publicly available maintenance cost data and experience associated with off-shore wind projects. Off-shore wind projects are expected to require more maintenance over the long-term due to salt and moisture-related problems such as corrosion. The electrical components are particularly susceptible if not well protected. Cranes and jack-up rigs that are typically employed for installation are extremely costly for maintenance and lead designers to develop integral cranes. The occasions for accommodating (low) winds that allow lifting are also expected to be less frequent for offshore projects - especially in winter months in the temperate zones.

Figure 3-10 provides European crane day-rate cost data from Ref. 5 along with comparative day rates for North America, on-shore projects (see bottom of figure). It is assumed that the data apply only to large MW-scale projects with nacelle and other lift weights in excess of 60 tons. For this paper, a piece-wise linear, least-squares fit to the off-shore cost data was developed (see solid line). It should be noted that the off-shore costs increase dramatically when the lift height exceeds 100 m. These cost estimates were added to the O&M model and comparative results derived. The results are discussed below.

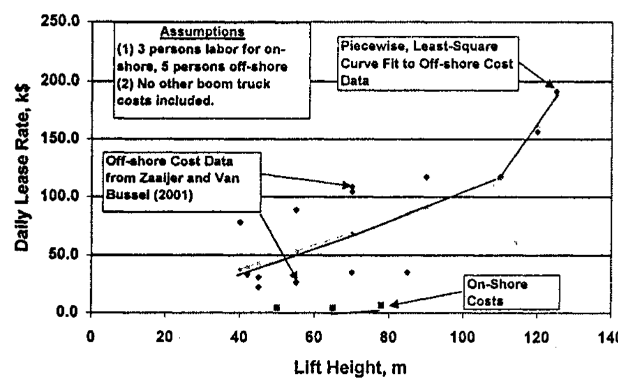

Figure 3-10. Daily Rate for Off-shore Crane Lease (Data from Ref. 5)

6. SENSITIVITY STUDIES

The model was applied to evaluate and compare the sensitivity to the assumptions summarized in Table 6-1 - all applied to a 100-MW project. The table compares the cumulative 20-year total O&M costs using prior assumptions for warranty and inflation. All cases assume that the hub height is equal to the rotor diameter.

Table 6-1. Factors Evaluated in Sensitivity Study

(1) Base Case: 600- to 750-kW wind turbines
(2) 2-MW wind turbines
(3) 2-MW turbines, twice normal failure rate (FR) for gearboxes and generators
(4) 2-MW wind turbines, integral crane
(5) Off-shore, 2-MW turbines, normal FR
(6) Off-shore, 2-MW turbines, integral crane

The results, shown in Figure 6-1, indicate that the lowest O&M costs arise from on-shore projects that employ integral cranes, followed closely by off-shore projects that employ integral cranes. The reason that there is a greater cost off-shore is that the crane costs are higher off-shore and the same benefit factor is applied to both cases.

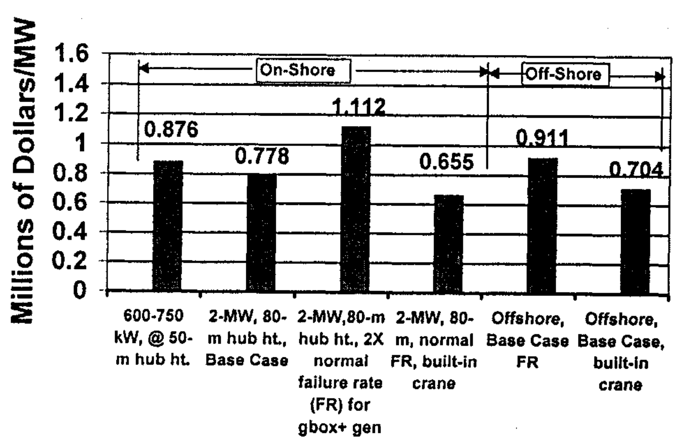

Figure 6-1. Results of Sensitivity Study

7. CONCLUSIONS

(1) The long-term O&M cost drivers are generally the failure rates and replacement or rebuild costs of gearboxes, generators, yaw systems.
(2) 20-year, cumulative wind turbine O&M costs range from 65 to 90 cents per watt - with the l lower cost range attributable to turbines with integral cranes.
(3) Costs for 600- to 750-kW turbines are 12 percent higher than for 2-MW turbines.
(4) Larger wind turbines lead to slightly lower O&M costs, as long as cranes are readily available.
(5) The cost for cranes is a major concern for large wind turbines - leading to 40 percent of the O&M costs over 20 years.
(6) Crane costs vary significantly with the region, their availability and their proximity to the site.
(7) O&M costs for offshore projects are approximately 17 percent greater than on-shore costs.
(8) O&M costs for large wind turbines (both on and off-shore) are projected to be significantly lower for machines that have integral cranes.

8. REFERENCES

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BPA Wind Integration Services

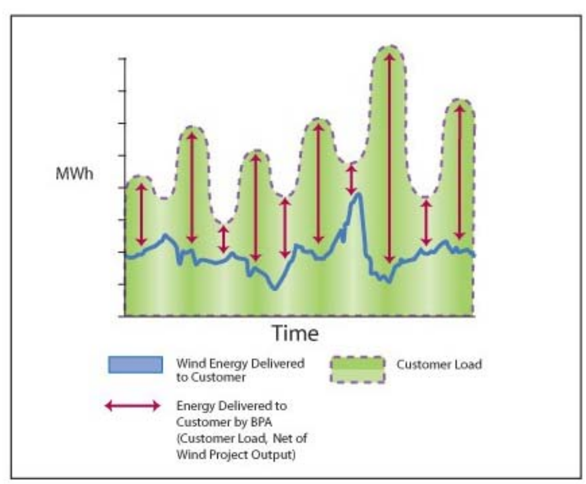
Over the past two years, BPA has undertaken an extensive research and development effort to evaluate the costs and opportunities associated with integrating wind energy into the Federal Columbia River Hydroelectric System (FCRPS). This evaluation phase is now complete and we are pleased to announce two new services that will utilize the flexibility of the hydro system to integrate wind energy into our control area on behalf of electrical utilities in the Pacific Northwest. BPA has established a goal of providing up to 450 MW (nameplate) of wind integration services over the 2004-2011 time period. At least 200 MW of these services will be earmarked for public power customers.

Network Wind Integration Service

Network Wind Integration Service has been designed to serve the needs of public power customers with loads embedded in the BPA control area who elect to purchase all or a portion of their power from a new wind resource. Once the customer has (a) signed a bilateral power purchase agreement with a new wind resource, (b) procured firm transmission and (c) determined a scheduling agent for the power, the BPA Power Business Line will use its hydro system to integrate the scheduled output of the resource with the customer's load. The scheduled energy from the wind resource will offset an equal amount of HLH and LLH PF energy that BPA otherwise would have provided. BPA will continue to meet and follow the customer's load at all times, including during those periods when there is no output from the wind resource. The customer's PF demand billing determinant will not be reduced for the amount of wind generation scheduled to its load on the hour of the generation system peak. BPA PBL cannot count on the generation being there and thus must hold sufficient generating capacity available to fully back up the resource. The PF Load Variance charge will continue to be based on the customer's Total Retail Load, so will not be reduced by the amount of wind generation.

The customer will be charged a fee of $4.50/MWh for all scheduled energy that BPA integrates into its system. This fee may be subject to annual escalation depending on the length of the requested contract. For contracts that extend beyond the current rate period, the fee will be escalated at the rate associated with the Gross Domestic Product Implicit Price Deflator, which is the same index used to escalate the Federal Production Tax Credit for wind.

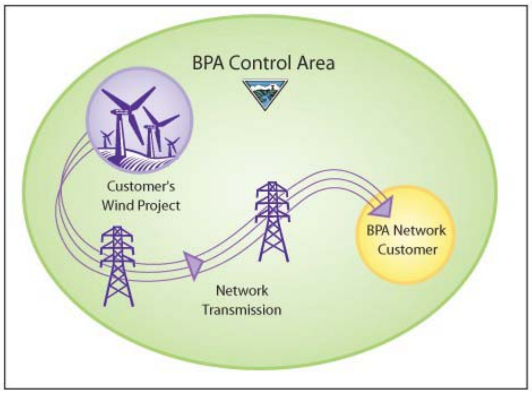
Network Wind Integration Service



Transmission

With respect to transmission, customers will be able to import power from new resources using their NT transmission rights. BPA will work with public power customers and wind project developers to identify regions of the BPA grid best suited for wind development with respect to the availability of firm transmission. BPA plans to take an active role in developing a diversified portfolio of regional wind resources. This diversification will be a key factor in increasing the amount of wind energy selling into the BPA grid.

Network Wind Integration Service
Transmission



One Transmission Wheel Using Customer's Network Transmission Rights

Scheduling and Generation Imbalance

The customer (or its scheduling agent) will be responsible for transmission arrangements and for scheduling the wind output from the point where the generation is integrated into the BPA transmission system to a point of delivery where the customer's system interconnects with the BPA transmission system. Generally, the customer will need to request a new Point of Receipt under its NT transmission contract and there is no guarantee that firm transmission capacity will be available.

The wind project operator or its scheduling agent will provide the Transmission Business Line with a Day-Ahead Generation Estimate followed by revisions up to 30 minutes before the start of the hour if changes are required. The project operator will be responsible for paying the BPA TBL Generation Imbalance charges for deviations between wind project actual generation and the Generation Estimate. Whether the project operator directly assigns these generation imbalance costs to project participants or not will depend on the specific contractual agreements between those entities. Accurate wind forecasting will minimize these charges. If changes are made to the Generation Imbalance tariff in the future, these changes will be amended to the Network Wind Integration Service Contract.

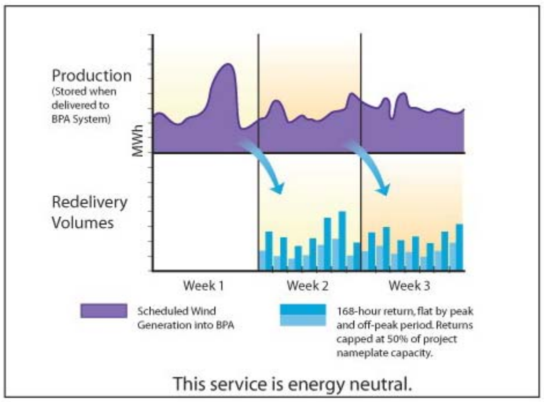
Storage and Shaping Service

Storage and Shaping Service has been designed to serve the needs of utilities and other entities outside of the BPA Control Area who have chosen to purchase the output of a new wind resource but do not want to manage the hour-to-hour variability associated with the wind output. To facilitate such an arrangement, BPA's Power Business Line will take the hourly output of new wind projects physically located and/or scheduling directly into the BPA Control Area, integrate and store the energy in the Federal hydro system, and redeliver it a week later in flat peak and off-peak blocks to the power purchasing customer. In order to help reduce transmission costs, returns will be capped at 50 percent of the participant's share of project capacity. The base charge for storage and shaping service is $6.00/MWh, escalated annually at the GDP Implicit Price Deflator.

Transmission

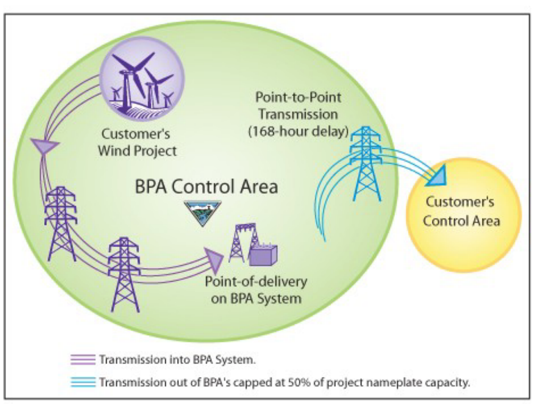
Storage and Shaping Service is for energy delivered *to* and *from* the BPA system. Thus, two transmission wheels are required to receive the service. Generators will be responsible for Generation Imbalance charges for generation scheduled into the BPA system. BPA expects that the transmission arrangements will vary from project to project, depending on (a) the locations of the project and the end-use buyer, and (b) the availability of firm transmission along both transmission paths.

Storage & Shaping Service
Power Redelivery



BPA is committed to working with potential customers to minimize the transmission costs associated with Storage and Shaping Service. So far, we have been able to limit the cost of the wheel out of our system by agreeing to cap returns at 50% of the nameplate rating of the participating project. During periods when generation exceeds the 50% threshold (i.e. greater than 50 MW on a 100 MW project), BPA will bank this excess energy in a storage account. When generation falls below the 50% threshold, BPA will draw from the Excess

Storage & Shaping Service
Transmission



Customer purchases point-to-point transmission out of BPA's Control Area into their own area.

Energy account and redeliver additional quantities above and beyond the current redelivery obligation. This will reduce the amount of transmission required to move the stored energy out of the BPA system. We are also examining a number of potential cost-saving approaches to the transmission wheel into our system.

BPA plans to work closely with project developers, Investor Owned Utilizes and other entities with well-developed and active purchasing plans to help determine which projects can be most efficiently integrated into the BPA system. Siting projects in areas of the grid with minimal congestion and in a way that takes advantage of regional diversity in wind patterns is essential to the growth of cost-effective wind energy in the Pacific Northwest.

For More Information

To learn more about Network Wind Integration Service or Storage and Shaping Service, please contact your PBL or TBL Customer Account Executive or the BPA PBL Renewable Power Group at (503) 230-3530. We look forward to working with you on these exciting new services.

GROVE

GMK7550

product guide

features

- 550 ton (450 mton) capacity
- 197 ft (60 m) 5 section full power boom
- Patented TWIN-LOCK™ boom pinning system
- 82 ft - 240 ft (25 m - 73 m) lattice luffing jib
- 39 ft - 230 ft (12 m - 70 m) fixed lattice jib
- 430 ft (131 m) overall tip height
- Grove MEGAFORM boom
- New control console with EKS5 and ECOS
- Right side mounted cab stows to the rear
- Superstructure cab tilts up to approx 20°
- 264,500 lbs (120 Tonnes) hydraulically installed/removed counterweight
- 255 hp (190 kW) Mercedes OM906LA diesel, water cooled superstructure engine
- 563 hp (420 kW) Mercedes, diesel, water-cooled turbocharged carrier engine
- 53 mph (85 km/h) travel speed
- Boom removal and trailing boom kits (less dolly)
- Self removable rear outrigger box
- Optional 8th axle
- MEGATRAK™ independent suspension system

contents

Features	2
Specifications	3
Dimensions	5
Jib Dimensions	6
Counterweight Dimensions	8
Travel Proposals	9
Main Boom Range/Charts	11
Luffing Jib Range/Charts	14
Fixed Lattice Extension	25
Special Offset Fixed Lattice Extension	28
Heavy Duty Jib Extension	31

Manitowoc Crane Group

All Terrain Crane

features

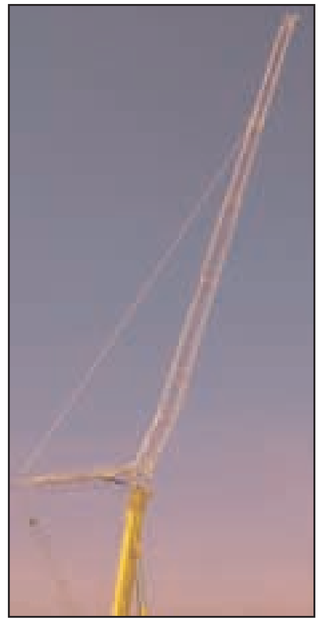
2

The operator's cab on the GMK7550 uses the new EKS5 LMI system and ECOS (Electronic Crane Operating System) with a combined dual screen display mounted on a tiltable swing arm.

The Mercedes OM 502 LA, 8 cylinder carrier engine provides 563 (420 kW) horsepower.

The superstructure is powered by a Mercedes OM906 LA 6 cylinder 255 horsepower (190 kW) engine.

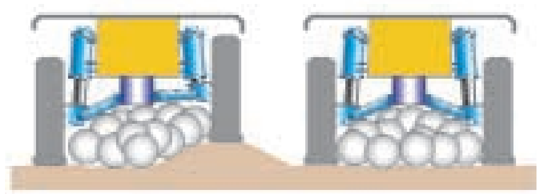
The new superstructure cab stows to the rear and swings hydraulically to the right side of the crane for operation. Stationary heating and A/C are standard.



A sturdy 240 ft. (73 m) luffing jib on 179 ft. (54,6 m) of main boom provides up to 410 ft. (125 m) max tip ht with approximately 295 ft. (90 m) of working radius.

The TWIN-LOCK boom pinning system-a Grove patented design - runs inside a five section MEGAFORM boom.

The exclusive Grove MEGATRAK™ independent suspension system allows all wheels to be on the ground at all times; now with top steering on rear axles.



The rear outrigger box can be removed and replaced with an 8th axle for travel situations demanding additional axle weight distribution, (shown below with optional aluminum wheels).

specifications

Superstructure

Boom

53 ft. - 197 ft. (16 m - 60 m) five section, full power boom with patented TWIN-LOCK™ boom pinning system. Maximum tip height: 207 ft. (63 m).

Boom Elevation

Two lift cylinders with safety valves provide boom angles from -3° to +82°.

Lattice Jib

Luffing jib is a lattice design with lengths of 82 ft. -240 ft. (25 m - 73 m) in sections of 20 ft. (6 m). The luffing jib converts to a fixed offset lattice jib providing lengths of 39 ft. -230 ft. (12 m - 70 m) offsettable at 3° and 25°.

Load Moment & Anti-Two Block System

Graphic display load moment and anti-two block system with audio/visual warning and control lever lockout. These systems provide electronic display of boom angle, length, radius, tip height, relative load moment, maximum permissible load, load indication and warning of impending two-block condition.

Cab

All aluminum construction cab is tiltable (approximately 20°) and includes safety glass and adjustable operator's seat with hydraulic suspension. Other features include engine dependent hot water heater, air conditioning, armrest integrated crane controls, and ergonomically arranged instrumentation. Cab hydraulically stows to the rear of the superstructure for highway travel.

Swing

3 axial piston fixed displacement motors provide swing speed of 0 - 1 RPM thru planetary gear box. Also provided is a spring applied, hydraulically released automatic swing brake with foot operated release for free swing.

Counterweight

264,500 lbs. (120 Tonnes) consisting of various sections with hydraulic installation/removal system (see counterweight configuration on page 8).

Engine

Mercedes OM906LA, diesel, 6 cylinders, water cooled, turbocharged, 255 HP (190 kW) at 1800 rpm. Max. torque: 811 ft./lbs. (1100 Nm) at 1300 rpm. Engine emission: EUROMOT/EPA/CARB (off highway).

Fuel Tank Capacity

79 gal. (300 L).

Hydraulic System

5 separate circuits, 3 axial piston variable displacement pumps with electronic power limiting control, 1 axial piston variable displacement pump for slewing and 1 fixed displacement pump for auxiliary gears. Standard thermostatically controlled oil cooler keeps oil at optimum operating temperature. Tank capacity: 428 gal. (1620 L)

Control system

Full electronic control of all crane movements is accomplished using electrical control levers with automatic reset to zero. Controls are integrated with the LMI and engine management system by CAN-BUS.

Hoist

Main and auxiliary hoist are powered by axial piston variable displacement motor with planetary gear and brake. "Thumb-thumper" hoist drum rotation indicator alerts operator of hoist movement.

	Main Auxiliary	Auxiliary
Line length:	1509 ft. (460 m)	2,264 ft. (690 m)
Rope diameter:	24 mm	24 mm
Line speed:	443 ft/min (135 m/min)	443 ft/min (135 m/min)
Line pull:	24,729 lbs. (110 kN)	24,729 lbs. (110 kN)

Electrical system

24 V system with three-phase alternator 28 V/100 A
2 batteries 12 V/170 Ah.

* Optional equipment

* Engine-independent hot water heater, with engine pre-heater
* Second spotlight
* Stereo/CD player
* Lift enhancement system
* 360° positive swing lock

* Denotes optional equipment

GMK7550

GROVE

specifications

Carrier

4

Chassis

Special 7 axle carrier, welded torsion resistant frame is fabricated from high-strength steel.

Outrigger System

Hydraulic two-stage outrigger beams are extended by a single hydraulic cylinder and two cables. Outriggers can adjust to two positions:

Fully extended (100%) - 29' 2" (8.9 m)
Partially extended (50%) - 20' (6.1 m)

Four 32 in. x 32 in. (810 mm x 810 mm), self stowing, steel outrigger pads provide rigid lifting base. Outrigger controls are located on both sides of the carrier. Electronic level indicators are located next to each outrigger control box. Outrigger pad load indication through ECOS and carrier controls.

Engine

Mercedes, diesel, 8 cylinders, water-cooled, turbocharged, 563 HP (420 kW) at 1800 rpm.
Max. torque: 1991 ft. lbs. (2700 Nm) at 1080 rpm.
Engine emission: EPA/CARB (non highway).

Fuel Tank Capacity

132 gal. (500 L).

Transmission

Allison automatic HD 4076, 7 forward and 1 reverse speed. Transfer case with 2 speeds and inter-axle differential lock.

Drive/Steer

14 x 6 x 14.

Axles

7 axles. 1, 4 and 5 are drive/steer. Axles 2, 3, 6 and 7 are steer only.

Suspension

GMK7550 features the Grove exclusive MEGATRAK™ suspension. This revolutionary design features an independent hydroneumatic system with hydraulic lockout acting on all wheels. The suspension can be raised 6-1/2" (170 mm) or lowered 5" (130 mm) both longitudinally and transversely and features an automatic leveling system for on-highway travel.

Tires

14 tires, 20.5 R25.

Steering

Dual circuit steering system is hydraulic power assisted with emergency steering pump.
Axles 1, 2, 3, 6 and 7steer on highway.
Separate steering of the 4th, 5th,6th and 7th axles for all wheel steer and crab-steer, controlled by an electric rocker switch.

Brakes

A dual circuit air system operates on all wheels with a spring-applied, air released parking brake acting on axles 2, 4, 5 and 7.
An air dryer is fitted to remove moisture from the air system.
Standard engine compression brake and transmission retarder.

Cab

Two-man, aluminum construction driver's cab includes the following features: safety glass; driver and passenger seats with hydraulic suspension, engine-dependent hot water heater and air conditioning.
Complete instrumentation and driving controls.

Electrical System

24 V system with three-phase alternator 28 V/100 A,
2 batteries 12 V/170 Ah.

Maximum Speed

53 mph (85 km/h) with 20.5 R25 tires.

Gradeability (theoretical)

32% with 20.5 R25 tires. (14x6x14)
50% with 20.5 R25 tires. (14x8x14)

Miscellaneous Standard Equipment

Boom removal kit; trailing boom kit (less dolly), additional hydraulic oil cooler; removable rear outrigger box, spare tire and wheel; tool kit; fire extinguisher; radio/cassette player in carrier cab.

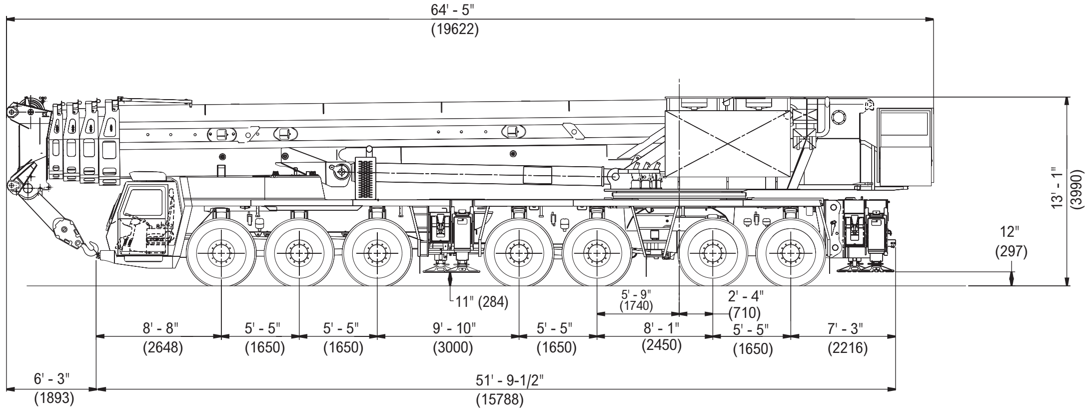
* Optional Equipment

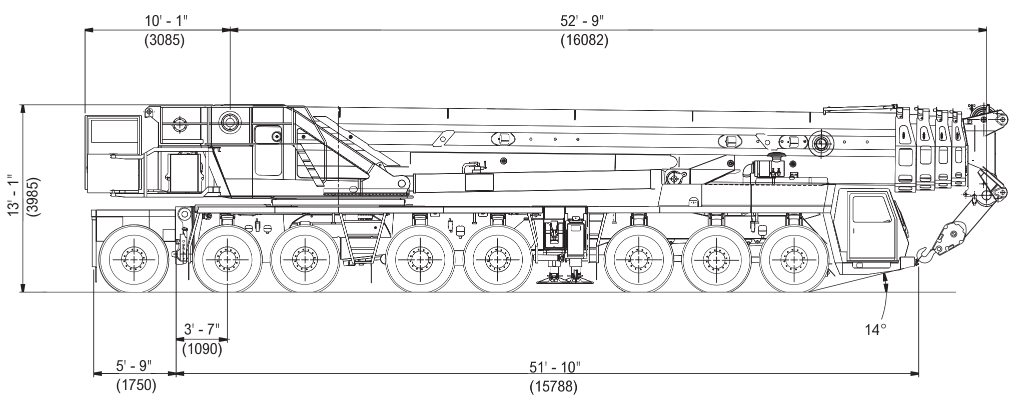
* 14 x 8 x 14 (1,2,4 and 5 are drive/steer)
* Engine-independent hot water heater, with engine pre-heater
* Tachograph

** Denotes optional equipment*

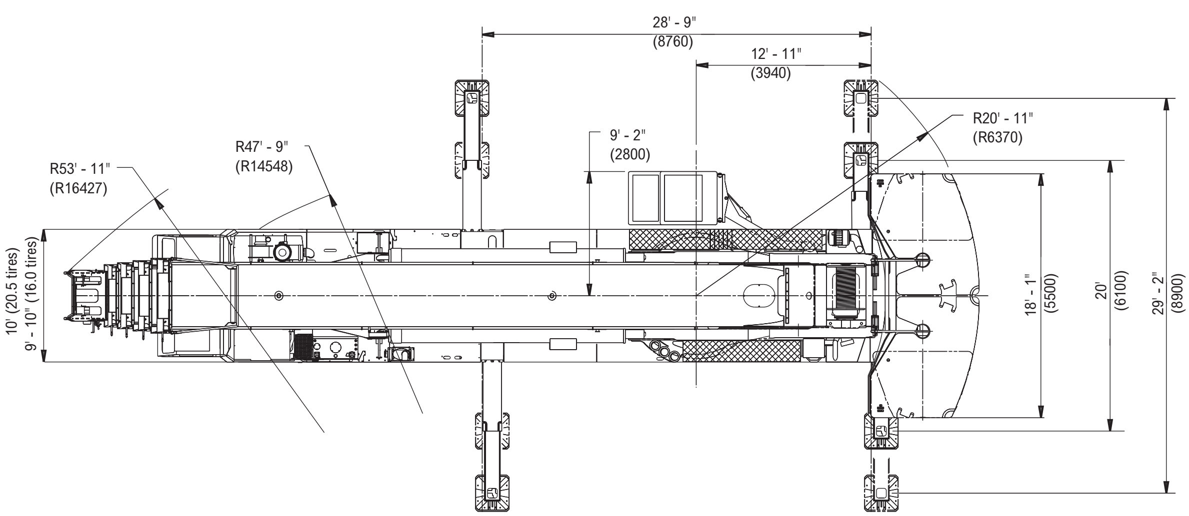
dimensions

5





Shown with
8th axle

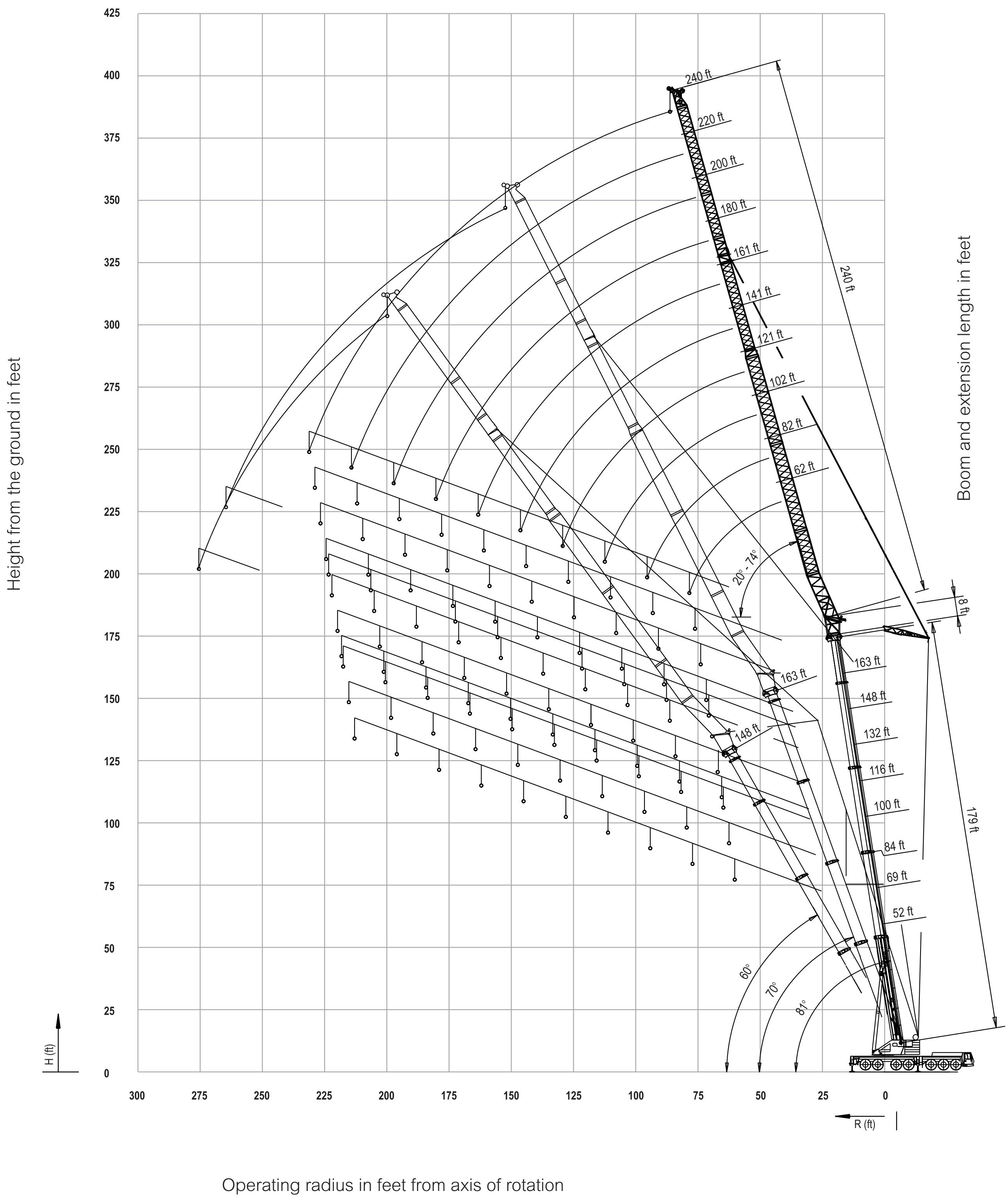


GMK7550

GROVE

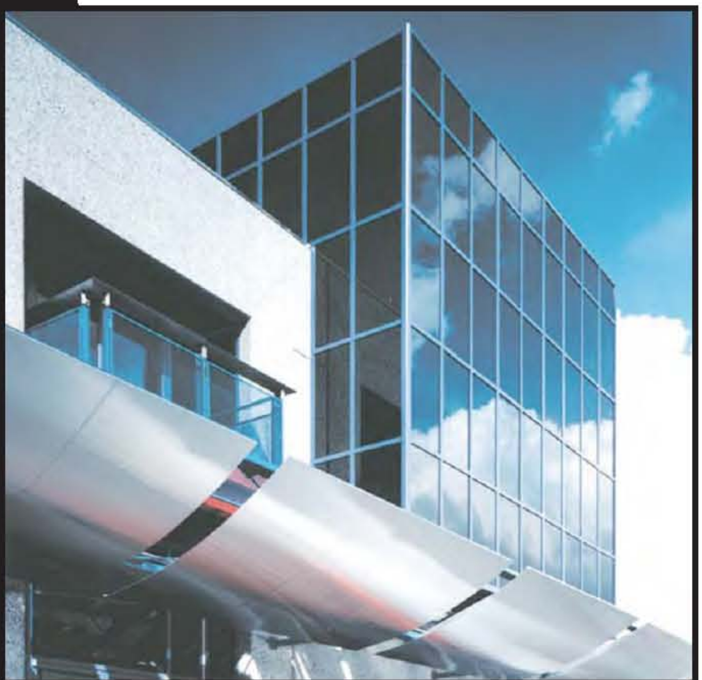
working range

240 ft Hydraulic Luffing Jib



THIS CHART IS ONLY A GUIDE AND SHOULD NOT BE USED TO OPERATE THE CRANE. The individual crane's load chart, operating instructions and other instructional plates must be read and understood prior to operating the crane.

HANDBOOK



Self-Generation Incentive Program

January 27, 2006 - Rev. 0

Provides financial incentives for installing clean, efficient, on-site distributed generation

Southern California Gas Company

A Sempra Energy utility

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL Company

San Diego REGIONAL ENERGY OFFICE

SDGE

A Sempra Energy utility

PG&E Pacific Gas and Electric Company

What's New in the 2006 Self-Generation Incentive Program

On December 15, 2005 and January 12, 2006, the CPUC approved decisions that adopt a number of important modifications to the Self-Generation Incentive Program (SGIP). This page summarizes the major changes from the previous SGIP program year. Details of the SGIP requirements and application process are contained in the new 2006 SGIP Handbook.

- Program year 2006 shall be a transition year, as SGIP incentives for photovoltaic projects will be incorporated into the California Solar Initiative (CSI) on January 1, 2007.
- Increased Incentive Budget for Solar Technologies
  - For 2006, the solar incentive budget[1] was increased an additional $270 Million for a total solar incentive budget of $307.5 Million. The new budgets by Program Administrator are:

Pacific Gas and Electric Company	$172,800,000
Southern California Edison Company	$121,050,000
Southern California Gas Company	$39,600,000
San Diego Regional Energy Office	$49,050,000

- New Incentive Rates and Structure
  - In 2006, the incentive rate for solar technologies is $2.80/Watt. However, 2005 applications that are on the waiting list as of December 15, 2005, and are "rolled over" to 2006 will receive $3.00/Watt. Those Host Customers that choose to withdraw their 2005 waiting list applications from the program will receive a full refund of their application fee.
  - To facilitate the transition to the California Solar Initiatives (CSI) program, the SGIP technologies levels have been reorganized as summarized in the following table.

Incentive Levels	Eligible Technologies	Incentive Offered ($/Watt)	Minimum System Size	Maximum System Size	Maximum Incentive Size
Level 1 Solar	Photovoltaics	$2.80/W $3.00/W for 2005 Wait List Applications "Rolled Over" to 2006	30 kW	5 MW	1 MW
Level 2 Renewable Non-Solar	Wind turbines	$1.50/W	30 kW	5 MW	1 MW
	Renewable fuel cells	$4.50/W			
	Renewable fuel microturbines and small gas turbines	$1.30/W	None		
	Renewable fuel internal combustion engines and large gas turbines[2]	$1.00/W	None		

[1] "Incentive budgets" are the program budgets <u>without</u> administrative and M&E costs included.

[2] Large gas turbines are ≥ 1 MW in capacity. Small gas turbines and microturbines are <1 MW in capacity.

Incentive Levels	Eligible Technologies	Incentive Offered ($/Watt)	Minimum System Size	Maximum System Size	Maximum Incentive Size
Level 3 Non-Renewable Non-Solar	Non-Renewable fuel cells	$2.50/W	None	5 MW	1 MW
	Non-Renewable & Waste Gas fuel microturbines and small gas turbines	$0.80/W			
	Non-Renewable & Waste Gas fuel internal combustion engines and large gas turbines	$0.60/W			

- Host Customer Rights to Incentive Reservation
  - Starting in 2006, Host Customers have exclusive rights to the incentive reservation.
  - Host Customers can be the Applicant or appoint a third party to be Applicant on their behalf. In either case, the Host Customer retains rights to the incentive reservation.
  - Host Customers and System Owners (if different from the Host Customer) can jointly assign, in writing, payment of the incentive to a third party.
  - The Host Customer and the System Owner (if different from the Host Customer) are both parties to the SGIP contract.
- Eligible System Size
  - In 2006, the maximum eligible system size, for all technologies, is limited to 100% of the Host Customer's historic peak demand. This does not apply to 2005 photovoltaic, wind turbine or renewable fuel cell waiting list applications that are made active for 2006. For those applications, the 2005 SGIP rules allowing system sizing to 200% of the Host Customer's historic peak demand or alternate sizing based on Host Customer's annual electric energy consumption are permitted

Scott Debenham CEM
11317 Valle Vista Rd Lakeside, CA 92040
Phone 619-334-9541 Email – Scott@DebenhamEnergy.com

Qualifications

Education, Licenses, and Achievements

MBA-Finance, University of Michigan, Ann Arbor MI
BS-Aeronautical Engineering, California Polytechnic State University, SLO. Tau Beta Pi
Certified Energy Manager (CEM)
Nuclear Submarine Electrical Officer - Certified Power Plant Engineer by Naval Reactors/DOE
Solar Turbines – Performance Analysis, Applications Engr. Project Manager, and Product Management
President, Association of Energy Engineers – San Diego Chapter
Co-Chair, Energy Services Coalition (ESC) – California Chapter
Co-Chair, Renewable/Energy Efficiency Subcommittee – Border Air Workgroup
Proficient in Spanish Language – Have given technical presentations in Latin America in Spanish
Have traveled to 35 countries

Experience – In Chronological Order

President, Debenham Energy, LLC

- Lead development efforts for Distributed Generation wind projects in California including prospecting, feasibility studies, project management and arranging financing.
- Business Development consulting work for AeroVironment's new "Building Integrated wind system".
- Product Development consulting work for a Compressed Air Energy Storage System (CAES) for a California based wind developer

Senior Project Developer – NORESCO LLC (2.5 years)

- Responsible for leading the project team, setting project milestones and budgets, preparing the proposals, establishing customer relationships and managing all of the project resources. Responsible for project profitability and schedule.
- Experience with DOE Super ESPC/IDIQ Contracts. Navy, BOP, USMC, Air Force.
- Successfully developed the Victorville Federal prison hybrid renewable energy efficiency project. This $5.5 million ESPC project included a 750 kW wind turbine and 70 kW photovoltaic covered parking array as well as an HVAC/Controls upgrade.
    - Lowest capacity factor financed utility scale wind turbine in the United States.
    - First utility scale wind turbine under the California Self Generation Program
    - Have given presentations at the Silicon Valley Manuf. Assn. and Energy 2004
    - Assisted in writing article that was published in AWEA.
    - Appealed and reversed the Utility/PUC Working Group decision on the eligible cost basis of the project which yielded an addition $180,000 for my customer.

Senior Project Manager – Planergy/EMI (1.5 years)

- Led implementation of Demand Side Management (DSM) energy efficiency projects with various municipal customers. Determined work priorities in accordance with project plans, project schedules and changing work demands. Managed relationships with client, contractors and equipment suppliers.
- Led development of an Energy Information System for sale to customers for analyzing and managing energy systems.

Software Development Project Manager – Epic Cycle Interactive (1 Year)

- Managed team of 5 software developers at client (Asera) site in San Francisco. Determined work priorities in accordance with project plans, schedules and changing work demands. Managed client relationship.
- Developed customer solutions at Asera, a venture capital (Kleiner-Perkins) funded startup to provide B2B e-commerce sell-side implementations via the internet.

Solar Turbines – Program, Product and Project Manager (11 years)

- Technical and commercial review of client specifications and preparation of proposals to meet design, code, quality and safety standards. Responsibilities also included client presentations and negotiations.
- Managed internal and external resources to design, install and test aftermarket turbomachinery equipment including managing change orders and approving invoices.
- 3 years experience in predicting and analyzing gas turbine, centrifugal compressor and steam system performance.
- Conducted field performance tests of turbine generator and compressor packages in order to verify contractual requirements.
- Led seminars on gas turbine and centrifugal compressor performance for major Oil and Gas clients (Pertamina, Unocal, Shell, Arco, Vico, Esso) in 4 Southeast Asian countries (Malaysia, Thailand, Brunei and Indonesia)
- Developed Oracle application for automating the design and costing/pricing of centrifugal compressor refurbishments. System is still in use today. Completed 20 days of Oracle training covering database design and application development.
- As Principal Application Engineer supported Latin America for 2 years. Gave presentations to PEMEX in Spanish. Numerous trips to Brazil (Petrobras) and Venezuela (Maraven/Lagoven/Corpoven) for power/cogeneration project development efforts.

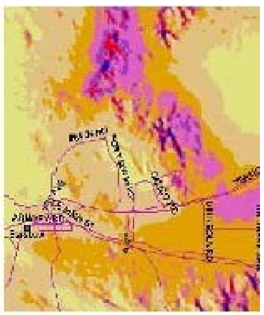
United States Navy – Nuclear Submarine Officer (5 years)

- Completed extensive 3 year Navy Nuclear Engineering training covering power plant design, thermo/fluid dynamics, chemistry, electrical engineering and controls.
- As Electrical Officer on fast-attack nuclear submarine USS Permit (SSN 594) responsible for managing overhaul, repair and acceptance testing of turbine generator, switchgear and related electrical equipment. Managed 15 highly trained electricians.
- As Submarine Engineering Officer of the Watch (EOOW) supervised operation, maintenance and casualty drills of complex integrated engineering systems including reactor, steam/condensate systems and power generation and distribution systems.

We Convert the Complex…

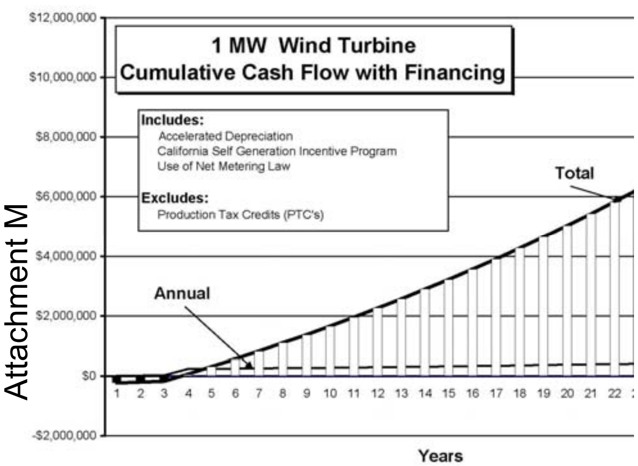
$$F_{i,j} = (2/\pi)\cos^{-1}\left[\exp\left(-\left\{\frac{(B/2)[1-(r_i/R)]}{(r_i/R)\sin\varphi_{i,j}}\right\}\right)\right]$$

Into Layman's Terms…



Class	Mean Power
1-	< 100
1+	100-200
2	200-300
3	300-400
4	400-500
5	500-600
6	600-800
7	> 800

For Making Good Business Decisions



Qualifications and Experience

- Aeronautical Engineer, Cal Poly, Honors
- MBA Finance, University of Michigan
- Nuclear Submarine Officer (5 years)
- Solar Turbines - Power/Cogen (10 years)
- Managed Development of Turnkey Self-Financed Victorville (CA) Federal Prison Project (750 kW)
- Multiple Projects in Development

Numerous References can be Provided

Wind Distributed Generation (DG)

Utility-scale wind turbines are well suited to reduce power costs at grid connected industrial, educational, and some commercial facilities. Locating the wind turbine on site and "after the meter" will displace expensive utility power and provide excellent economics.

Preliminary Analysis

If you have a good wind resource, a large electrical load and either high electric rates or a State Incentive Program then we will provide a Preliminary Analysis. This will provide an estimate of the economics of on-site wind generation and determine if a more detailed study is justified.

Feasibility Study

Visit the site and provide a Feasibility Study including:

- Evaluate the site suitability
- Review your electrical system
- Analyze your electricity bills
- Evaluate climactic conditions
- Determine the optimal turbine location
- Refine the wind assessment
- Determine permitting requirements
- Complete FAA, State Incentive and use permit applications
- Determine the appropriate turbine model
- Provide a comprehensive economic model

Debenham Energy LLC provides a complete range of services including site evaluation, equipment selection, procurement, turbine installation and extended equipment operations, maintenance and repair. Based on the customer's financial and technical capabilities and desires we can provide a turnkey project including equipment ownership and operation, pure consulting services or a negotiated hybrid between these 2 extremes.

Financing Options

- Simple Cash Purchase
- Equipment Lease
- Equipment owned and operated by a separate entity with electricity sold to the customer.

We provide advice and recommendations on applicable state, federal and other incentive programs as well as financing.

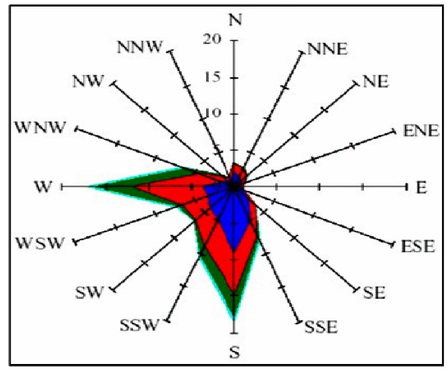
Confidence in the Process and the Outcome

We work in a non-adversarial partnership environment. This is critical for evaluating options for project structuring. Since wind technology and financing options are not our customers core competencies it is often in their best interests to do due diligence. We can assist our customers in identifying experienced consultants who can do independent due diligence. This helps foster a partnership relationship and is generally time and money well spent.

Scott Debenham

Mission

Reduce your electric bills with a proven, reliable and renewable source of power generation – WIND



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Distributed Generation Wind Systems

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